United States Environmental Protection Agency
Office of Water Washington, DC 20460
August 2020

Response to Public Comments for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

INTRODUCTION

This document provides responses to all significant comments submitted on EPA's proposed effluent limitations and guidelines rule for the Steam Electric Power Generation Point Source Category. EPA's proposal was published in the Federal Register on November 22, 2019 (84 FR 64620) and the public comment period closed on January 21, 2020. Submitted comments are available electronically through *http://www.regulations.gov* by searching Docket ID No. EPA-HQ-OW-2009-0819 and in hard copy at the EPA Docket Center Public Reading Room. The telephone number for the Water Docket is (202) 566-2426 and the telephone number for the Public Reading Room is (202) 566-1744. The Water Docket assigned a unique Document Control Number (DCN) to each comment submittal with the following format: EPA-HQ-OW-2009-0819-xxxx, where the four digit number at the end is unique to that comment submittal. Where a commenter submitted more than one file, EPA has included an attachment number, for example EPA-HQ-OW-2009-0819-xxxx-A1 (A2, A3, etc.)

This document is organized into two parts as indicated in the Table of Contents below. To organize the comments and to facilitate EPA's responses, EPA classified comment submittals by topic, available in Part 1 of this document. If a specific comment submittal addressed multiple topics, EPA subdivided the submittal by topic. Comments or portions of comments assigned to specific topics are referred to as "comment excerpts." All of the individual comment excerpts classified to a specific topic are reproduced within the comment code corresponding to that topic. Within a specific comment code, the comment excerpts are often sorted in order of the DCNs. However, comment excerpts may also be ordered within a specific comment code so that similar comment issues are grouped together. EPA's responses to each comment code topic are available in Part 2 of this document. Similar to comment excerpts, EPA's responses are organized by comment code. The Table of Contents provides a list of comment topics covered in Part 1 and Part 2 of this document.

To support the reader in finding and understanding the comments and their responses, EPA has provided the following as part of this document:

- A listing of the major support documents for the rulemaking, referenced throughout the comment responses.
- Comment excerpts by comment topic (located in Part 1).
- Comment responses by comment topic (located in Part 2).
- A list of acronyms used throughout the comment response document.
- A comment submittal index ordered by DCN (and Affiliate Name) with the corresponding list of comment codes covered in the comment submittal (Appendix A).

EPA notes that many commenters raised the same, similar, or related issues. Therefore, the response to a specific code may refer the reader to other responses that provide additional details on a comment topic. While EPA endeavored to be accurate and consistent in assigning comment excerpts to topics, and in referencing other relevant responses, some excerpts may have content that overlaps multiple topics. Accordingly, readers may find it helpful to read this entire document to obtain EPA's response regarding a given general topic. Moreover, in many instances, particular responses presented in this document include references to other portions of the administrative record, including the preamble and other major support documents for the rulemaking (see below). Accordingly, this document, together with the preamble and the rest of the administrative record should be considered collectively as the Agency's response to all of the significant comments submitted on the proposed rule.

Due to the volume of comments received, some responses in this document may not reflect the language in the preamble or final rule in every respect. Where the response is in conflict with the preamble or the final rule, the language in the final preamble and rule controls and should be used for purposes of understanding the scope, requirements, and basis of the final rule. Although portions of the preamble to the final rule are paraphrased in this document where useful to add clarity to responses, the preamble itself remains the definitive statement of the rationale for the final rule.

To locate other documents in the record, the reader should use the final rule record index. For information on the final rule record index and how to use it, see the Steam Record Index User's Guide.

The rule is supported, in part, by the following documents:

- Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental TDD), Document No. EPA-821-R-20-001.

- Supplemental Environmental Assessment for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental EA), Document No. EPA-821-R-20-002.

- Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA Report), Document No. EPA-821-R-20-003.

- Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA), Document No. EPA-821-R-20-004.

- Docket Index for the Revisions to the Steam Electric ELGs.

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ACRONYMS

ACE	Affordable Clean Energy.
BA	Bottom ash
BAT	Best available technology economically achievable, as defined by CWA sections 301(b)(2)(A) and 304(b)(2)(B).
BCA	Benefits and costs analysis.
BMP	Best management practice.
BOD	Biochemical oxygen demand.
BPJ	Best professional judgement.
BPT	The best practicable control technology currently available as defined by sections 301(b)(1) and 304(b)(1) of the CWA.
CAA	Clean Air Act.
CBI	Confidential business information.
CCR	Coal combustion residuals.
CFR	Code of Federal Regulations.
COD	Chemical oxygen demand.
COVID-19	Coronavirus Disease 2019
CP	Chemical precipitation.
CPP	Clean Power Plan.
CSAPR	Cross-State Air Pollution Rule.
CSC	Compact submerged conveyor.
CWA	Clean Water Act.
CWIS	Cooling water intake structures.
CWNS	Clean Watershed Needs Survey.
CWT	Centralized waste treatment.
DBP	Disinfection byproduct.
DCN	Document control number.
DOE	Department of Energy.
EA	Environmental assessment.
EGU	Electric generating unit.
EIA	Energy Information Administration.
EJ	Environmental Justice.
ELG	Effluent limitations guidelines and standards.

EO	Executive order.
EPA	U.S. Environmental Protection Agency.
EPC	Engineering, procurement, construction.
FA	Fly ash.
FDF	Fundamentally Different Factor.
FGD	Flue gas desulfurization.
FOIA	Freedom of Information Act.
GHG	Greenhouse gas.
HRR	High rate recycle.
HRTR	High residence time reduction.
IPM	Integrated Planning Model.
IQ	Intelligence quotient.
kW	Kilowatt.
MATS	Mercury and Air Toxics Standards.
MCL	Maximum contaminant level.
MCLG	Maximum contaminant level goal.
MDL	Method detection limit.
MDS	Mechanical drag system.
ML	Minimum level.
MQC	Minimum quantifiable concentration.
MW	Megawatt.
NAICS	North American Industry Classification System.
ND	Nondectect.
NERC	North American Electric Reliability Corporation.
NGCC	Natural gas combined cycle.
NODA	Notice of Data Availability.
NPDES	National Pollutant Discharge Elimination System.
NRD	Natural resource damages.
NRMRL	National Risk Management Research Laboratory.
NRWQC	National Recommended Water Quality Criteria.
NSPS	New Source Performance Standards.
NWQEI	Non-water quality environmental impact.

O&M	Operation and maintenance.
OAR	Office of Air and Radiation.
ORCR	Office of Resource Conservation and Recovery.
ORP	Oxidation reduction potential.
OW	Office of Water.
PM	Particulate matter.
POC	Pollutant of concern.
POTW	Publicly Owned Treatment Works.
PRB	Powder River Basin.
PSES	Pretreatment Standards for Existing Sources.
PSNS	Pretreatment Standards for New Sources.
PUC	Public Utility Commission.
QL	Quantitation limit.
RCRA	Resource Conservation and Recovery Act of 1976, 42 U.S.C. 6901 et seq.
RFA	Regulatory Flexibility Act.
Rfd	Reference dose.
RGGI	Regional Greenhouse Gas Initiative.
RIA	Regulatory impact analysis.
RO	Reverse osmosis.
S.U.	Standard units.
SBA	Small Business Administration.
SBREFA	Small Business Regulatory Enforcement Fairness Act.
SDWIS	Safe Drinking Water Information System.
T&E	Threatened and endangered species.
TBEL	Technology based effluent limit.
TCLP	Toxicity characteristic leaching procedure.
TDD	Technical Development Document.
TDS	Total dissolved solids.
TMDL	Total Maximum Daily Load.
TSS	Total suspended solids.
TWF	Toxic weighting factor.
TWPE	Toxic weighted pounds equivalent.

VIP	Voluntary incentives program.
WQBEL	Water quality based effluent limit.
WQI	Water quality index.
WTP	Willingness to pay.
ZLD	Zero liquid discharge.

Part 1
COMMENT EXCERPTS BY COMMENT CODE

1 Legal Authority

Commenter Name: Gary Hess
Commenter Affiliation:
Document Control Number: EPA-HQ-OW-2009-0819-8292-A1
Comment Excerpt Number: 2

Comment Excerpt:

I write, however, to emphasize two issues I urge EPA to consider when it evaluates the volume of comments submitted by citizens opposing EPA's proposal:

- The EPA has established a poor record, throughout the course of the current Administration, in assessing such comments. Additionally, the Agency is failing broadly to recognize and comply with the legal requirements governing decision making in notice-and-comment proceedings.
- When agencies such as EPA give insufficient weight to comments seeking governmental action to protect public health, and give excessive weight to comments opposing that action, there are profound and lasting negative consequences.

Since the Trump Administration Took Office in January 2017, Federal Courts Have Found, Repeatedly, that EPA Violated a Statutory Duty, Failed to Meet a Statutory Deadline, or Otherwise Acted Unreasonably; And Those Findings are Relevant to this Action

The Federal courts' findings regarding the poor quality of EPA's recent regulatory activity are relevant to this rulemaking. As EPA's Federal Register notice and related documents indicate, EPA developed this proposal after evaluating and choosing among a variety of assumptions and predictions.[2] However, conducting those evaluations and making those choices are not unique to this action. Those are tasks that EPA performs as a matter of course whenever it adopts rules or issues orders. Consequently, there is a track record showing how well, or poorly, EPA performs them.

EPA is expected to determine what options are legally available to it whenever it considers changing a person's rights or duties. (In addition, EPA determines the breadth of its options mindful that a court may later rule whether EPA made its determination correctly.) Thereafter, EPA is expected to choose the option that it predicts will best advance the public interest among the options legally available to it. Embedded in each step are predictions: predictions by EPA regarding how a court will likely rule on the breadth of the EPA's authority; and predictions by EPA regarding the outcomes that the public will enjoy or suffer depending on which of the various lawful options EPA chooses. Fortunately, the system also provides feedback on EPA's ability to make those predictions; we're able to keep score, and so should EPA.

Obviously, EPA's lack of success in selecting among the options that it thinks are legally available will be best known in the future. Several years may have to pass before the proponents of EPA's recent regulatory actions understand the harm that they've caused. However, we don't have to wait years to gauge EPA's ability to identify what options are legally available to it, and what options are not. Feedback regarding EPA's ability to evaluate competing assumptions and to correctly predict the reactions of reviewing courts is already available, because courts have already ruled on EPA's performance in making those predictions and assumptions. EPA should not ignore that record when it evaluates the comments contending that EPA has made similar errors in this rulemaking.

Consequently, I urge that as EPA proceeds, it -- and most particularly the political appointees who are most likely the advocates for the subject proposal – consider the feedback provided by the Federal courts' assessment of their recent efforts. In particular, when EPA evaluates comments in this proceeding contending that EPA will – due to its reliance on poor predictions, improper assumptions, or misinterpretation of the law -- insufficiently protect public health, the reviewers of those comments should remain mindful that, since January 2017, courts have repeatedly found that EPA has acted unreasonably or otherwise not in accordance with law.

To that end, see:

Clean Air Council v. Pruitt, 862 F.3d 1 (D.C. Cir., 2017)[3] (holding that EPA's June 2017 attempt to stay its previously adopted rules governing methane emissions from oil and natural gas facilities was unreasonable and unauthorized; citing various statements made by EPA in the Federal Register notice announcing the stay, the Court of Appeals found that "An examination of the record demonstrates that each of these statements is inaccurate", id., at 10, and, with respect to other statements made in EPA's Federal Register notice, "even a brief scan of the record demonstrates the inaccuracy of EPA's statements", id., at 12);

Air Alliance Houston v. EPA, 906 F.3d 1049 (D.C. Cir. 2018)[4] (vacating EPA's attempt to delay the effective date of rules to protect first responders and the public from accidents at chemical facilities; finding that EPA "has not engaged in reasoned decision making", id., at 1069; and, after describing EPA's analysis, concluding "This makes a mockery of the statute.", id., at 1064);

South Carolina Coastal Conservation League v. Pruitt, 318 F.Supp.3d 959 (D.S.C., 2018),[5] (granting summary judgment to the plaintiffs in a suit challenging the Trump Administration's "Suspension Rule" that sought to delay the effect of a rule promulgated in 2015 clarifying what types of waters are protected by the Clean Water Act; ruling that EPA and the Corps of Engineers were required to supply a "reasoned analysis" to support their action, the Court found:

"No such 'reasoned analysis' was provided in the promulgation of the Suspension Rule. By refusing to allow public comment and consider the merits of the WOTUS rule and the 1980s regulation, the agencies did not allow a 'meaningful opportunity' to comment. As such, the court finds that the agencies were arbitrary and capricious in promulgating the Suspension Rule. It vacates the Suspension Rule for this reason. To allow the type of administrative evasiveness that the agencies demonstrated in implementing the Suspension Rule would allow government to become 'a matter of the whim and caprice of the bureaucracy.' …. Certainly, different administrations may implement different regulatory priorities, but the [Administrative Procedure Act] 'requires that the pivot from one administration's priorities to those of the next be accomplished with at least some fidelity to law and legal process.' …. The agencies failed to promulgate the Suspension Rule with that required fidelity here. The court cannot countenance such a state of affairs." Id. at 967 [footnote omitted];

and enjoined the Suspension Rule nationwide, id. at 969);

Puget Soundkeeper Alliance v. Wheeler, (W.D. Wash., No. C15-1342-JCC, Nov. 26, 2018)[6] (also addressing the methods used as part of the Trump Administration's efforts to delay the effective date of the rule clarifying the types of waters protected under the CWA; finding that:

"By restricting the content of the comments solicited and considered, the Agencies deprived the public of a meaningful opportunity to comment on relevant and significant issues in violation of the APA's notice and comment requirements. [Cite omitted.] Therefore, the Agencies acted arbitrarily and capriciously when they promulgated the Applicability Date Rule." (id., at 10);

"The practical effect of the Applicability Date Rule was to repeal the CWA's definition of 'waters of the United States' set forth in the already-effective WOTUS Rule and replace it with a new definition. The definition of 'waters of the United States' is integral to the Agencies' enforcement of the CWA, as it defines the jurisdictional scope of the CWA itself. The Agencies refused to consider comments on the merits of the WOTUS Rule, the pre-2015 definition sought to be reinstated, or the scope of a possible future definition of 'waters of the United States.' Thus, the Agencies excluded comments that were relevant and important, and which could not be deferred until a later rule making." (id.); and

"In this case, the Agencies acted arbitrarily and capriciously when they excluded relevant and important comments prior to promulgating the Applicability Date Rule in violation of the APA's notice and comment requirements. The Agencies' failure to comply with the APA is a serious error. See Nat. Res. Def. Council v. E.P.A., 489 F.3d 1364, 1374 (D.C. Cir. 2007) ('The agency's errors could not be more serious insofar as it acted unlawfully, which is more than sufficient reason to vacate the rules.'). This is not a minor procedural error akin to those the Ninth Circuit has found may be cured by remand without vacatur.", id., at 12;

and vacating the Trump Administration's rule nationwide (id., at 13-14));

League of United Latin American Citizens v. Wheeler, 899 F.3d 814 (9th Cir., 2018)[7] (vacating EPA's March 2017 order that sought to maintain a tolerance for the pesticide chlorpyrifos on food, and remanding to EPA with directions to revoke all tolerances and cancel all registrations for chlorpyrifos within 60 days; noting that EPA "does not defend the 2017 Order on the merits.", id., at 817, "The EPA does not defend this suit on the merits", id., at 821; and "The EPA presents no arguments in defense of its decision.", id., at 829; and further holding:

"Here, the EPA's expressed intent to withhold action for years to come is 'unreasonable' as applied here, especially as petitioners' objections concern no factual issues that would require additional time to investigate. The EPA has had over a year to respond to the objections already, with no result.", id., at 828; and

"If Congress's statutory mandates are to mean anything, the time has come to put a stop to this patent evasion.", id., at 816 (emphasis added));

Environmental Law and Policy Center v. U.S. EPA, (N.D. Ohio, No. 3:17CV01514, Apr. 11, 2018)[8] (finding that "Although the CWA requires the U.S. EPA to approve or disapprove a state's § 303(d) list within thirty days, see 33 U.S.C. § 1313(d)(2), the U.S. EPA, in response to Ohio's 2016 impaired waters list, did neither."; and that "the conduct of the U.S. EPA vis-à-vis Ohio's 2016 Integrated Report manifested an apparently obdurate determination not to do its job" (emphasis added); and expressing concern regarding EPA's actions during the litigation, as follows:

"I am concerned, first, that the U.S. EPA did not inform plaintiffs that it was withdrawing its approval of Ohio's 2016 § 303(d) list until the eleventh hour and fifty ninth minute before their motion for summary judgment was to be filed.

I am concerned, second, that the U.S. EPA did not inform me that it was withdrawing its approval of Ohio's 2016 § 303(d) at all, either formally through a court filing or informally by email or otherwise. I only learned about the Agency's action after plaintiffs' counsel notified the Clerk about this significant change in circumstances. Defendants' oversight amplifies the whiff of bad faith arising from the timing of its inexplicably delayed notice to plaintiffs' counsel." (emphasis in original));

Pineros y Campesinos Unidos del Noroeste v. Pruitt, 293 F.Supp.3d 1062 (N.D. Cal., 2018)[9] (granting plaintiffs summary judgment in case opposing EPA's efforts to delay the effective date of rules to protect applicators and the general public from risks caused by restricted use pesticides; declaring that the subject rules have taken effect notwithstanding EPA's delaying efforts; and vacating EPA's actions announced in five separate Federal Register notices to the extent that those actions purported to delay the rules' effective date; finding that "In its opposition brief to Plaintiffs' motion for summary judgment, EPA does not attempt to justify, either substantively or procedurally, its repeated delays of the Pesticide Rule's effective date.", id., at 1066, and further stating that "Plaintiffs have introduced evidence that in November 2017 — mere days after EPA represented to this Court that the Pesticide Rule's implementation schedule was unchanged and that Plaintiff's concerns to the contrary amounted to the 'height of conjecture' — an EPA official informed stakeholders that EPA intended to delay the implementation schedule by 14 months to correspond to the delay in the effective date." id., at 1065);

Community In-Power and Development Association v. Pruitt, 304 F.Supp.3d 212 (D.D.C., 2018)[10] (stating that "the EPA admits that it has violated the Clean Air Act's prescriptions, insofar as the agency has failed to promulgate revised emission standards for the nine source categories of pollutants at issue in this case in a timely fashion.", id., at 215, and setting schedules for EPA to conclude rulemakings governing air emissions from various sources);

State of New York v. Pruitt, (S.D.N.Y., No. 18-CV-406 (JGK), June 12, 2018)[11] (stating that Administrator Pruitt and EPA "admit that they were under a mandatory duty pursuant to the Clean Air Act to issue [federal implementation plans] by August 12, 2017, and that they missed that deadline.", finding that New York and Connecticut "have demonstrated that they have suffered and will continue to suffer harm because of the defendants' failure to promulgate the FIPs", granting summary judgment to those States, and issuing an order requiring the Administrator and EPA to meet various deadlines to come into compliance);

In Re Ozone Designation Litigation, 286 F.Supp.3d 1082 (N.D. Cal., 2018)[12] (finding "There is no dispute as to liability: Defendants admit that the Administrator violated his nondiscretionary duty under the Clean Air Act … to promulgate by October 1, 2017 initial area air quality designations under the 2015 national ambient air quality standards … for ozone.", id., at 1084, and setting a schedule by which the Administrator must do so);

Public Employees for Environmental Responsibility v. U.S. EPA, 314 F.Supp.3d 68 (D.D.C., 2018)[13] (finding that "EPA has failed to demonstrate a viable legal basis for its refusal to conduct any search whatsoever in response to the plaintiff's straightforward FOIA request", id., at 82, and directing EPA to conduct and complete a search for records responsive to that request, to promptly disclose to the plaintiff any non-exempt records responsive to the request, and to produce an explanation for any documents withheld);

Sierra Club v. EPA, 895 F.3d 1 (D.C. Cir., 2018)[14] (addressing environmental groups petitions related to EPA determinations regarding hazardous air emissions from brick and ceramic kilns; finding that "EPA acted unreasonably by concluding that it is 'established' that the acid gas pollutants pose no cancer risk.", id., at 11; finding that "EPA acted unreasonably in finding that the noncarcinogenic health threshold for hydrogen chloride was established", id., at 12; finding that EPA further violated the Clean Air Act by failing to include an ample margin of safety with respect to emission limits that are to protect public health, id., at 12-13; finding that EPA's methodology for calculating Maximum Achievable Control Technology ("MACT") floors was inappropriate in several respects, id., at 13-15; and finding that EPA's determination to provide alternative emission floors for brick plants was "contrary to the statutory requirement of a standard based on the 'best' performing sources", id., at 16);

Association of Irritated Residents v. U.S. EPA, (N.D. Cal., No. 18-CV-01604-YGR, July 24, 2018)[15] (stating, in suit alleging that EPA had failed to act on a State plan to address ozone concentrations in California's San Joaquin Valley, that "EPA concedes that it has failed to fulfill this statutory duty"; finding EPA's request to extend the time for making its determination "excessive", and ordering EPA to act pursuant to the Court's schedule);

In re A Community Voice v. U.S. EPA, 878 F.3d 779 (9th Cir., 2017)[16] (finding that EPA had violated its duty to update lead-based paint and dust-lead hazard standards as mandated by TSCA and the Paint Hazard Act, and ordering EPA to propose and adopt rules under the Court of Appeal's schedule);

Connecticut v. Pruitt, (D. Conn., No. 3:17CV796 (WWE), Feb. 7, 2018)[17] (finding Administrator Pruitt and the EPA in violation of the Clean Air Act for failing to act on a petition filed by Connecticut, and ordering the Administrator and EPA to do so; the State had petitioned EPA to find that an upwind electric generating facility was significantly contributing to ozone problems in the State, and to order that facility to reduce its emissions);

Maryland v. Pruitt, 320 F.Supp.3d 722 (D. Md., 2018)[18] (granting plaintiffs' partial summary judgment in suit challenging EPA's failure to respond to a petition filed by the State under the Clean Air Act, and stating:

"Defendants concede at the outset that they are required by the CAA to either grant or deny a petition like the one filed by Maryland within a specified time period. Defendants also concede that they failed to carry out this nondiscretionary duty.", id., at 726);

Sierra Club v. Pruitt, 293 F.Supp.3d 1050 (N.D. Cal., 2018)[19] (granting summary judgment to plaintiffs in suit challenging EPA's attempts to delay the effective date of rules to protect the public from harms caused by formaldehyde emissions from composite wood products; finding EPA's action purporting to delay the effective date to be beyond EPA's authority and unlawful);

Northwest Environmental Advocates v. U.S. EPA, (D. Or., No. 3:12-CV-01751-AC, Dec. 12, 2018)[20] (finding that EPA had a nondiscretionary duty to review a State-adopted water quality criteria, and failed to do so; and ordering EPA to take remedial action; and rejecting EPA's belated objections to a schedule under which EPA is to establish TMDLs, stating, "The Court finds EPA has failed to establish a basis to change the Court's Order at this late stage of the proceedings. To the extent that EPA could not commit to meeting the April 11, 2019, deadline on account of its inability to affect the State's participation in the formulation of those new TMDLs, EPA knew of that limitation at the time that the Magistrate Judge issued the Findings & Recommendations and could have objected to the timeline then. The Court will not permit EPA to belatedly object to the two-year deadline almost a year after that deadline was established.", p. 15);

Gulf Restoration Network v. U.S. EPA, (E.D. La., No. 18-1632, Feb. 25, 2019) (in suit challenging EPA's approval of state-issued water quality standards, remanding the matter back to EPA after the agency acknowledged that it failed to follow Endangered Species Act requirements);

Blue Water Baltimore v. Wheeler, (D. Md.; No. GLR-17-1253, Mar. 22, 2019) (granting plaintiffs summary judgment after finding that EPA acted arbitrarily and capriciously when it refused to determine that industrial stormwater discharges in the Baltimore area were causing water quality violations and needed to be controlled by CWA permits); and

Sierra Club v. U.S. EPA, (N.D. Cal., No.18-CV-03472-EDL, Dec. 26, 2018)[21] (ordering EPA to provide documents in response to FOIA requests over EPA's objections; and stating "Defendant must devote sufficient resources to FOIA to meet the increasing demand, rather than delaying completion of its responses to proper requests for over four years, as proposed here.").

The above cases illustrate a dismal record that I urge EPA, and any reviewing Court, to consider if EPA proceeds with this proposal. [22]

Among the central issues in this rulemaking are: What confidence should EPA, the public, and the reviewing courts have in the assumptions and legal analysis that EPA offers in support of its proposal? Plainly, EPA is duty bound to evaluate the assumptions and analysis submitted by commenters that differ from the assumptions and analysis that EPA is now proposing. I believe that a fair evaluation of the competing assumptions and analysis should include consideration of the past performance of the entity making that proposal. In this case, the courts' findings in the above cases justify a substantial loss of everyone's confidence in EPA's decision-making ability. Since January 2017, EPA has shown that it was repeatedly unable to correctly identify what options were legally available to it, and repeatedly unable to forecast correctly an event merely months in the future: How would a court rule if the EPA's action were challenged?

If EPA still believes that the volume and content of above cases are not germane, I recommend that it consider the court rulings rejecting EPA's June 2017 attempt to stay the previously adopted rules governing methane emissions from oil and natural gas facilities, vacating EPA's attempt to delay the effective date of rules to protect first responders and the public from accidents at chemical facilities, enjoining EPA's "Suspension Rule" concerning the Clean Water Act's jurisdiction, vacating EPA's March 2017 action seeking to maintain a tolerance for the pesticide chlorpyrifos on food, rejecting EPA's efforts to delay the effective date of rules to protect applicators and the general public from risks caused by restricted use pesticides, and rejecting EPA's attempts to delay the effective date of rules to protect the public from harms caused by formaldehyde emissions from composite wood products, as data points that EPA ought to use as part of its effort to retrospectively review its rulemaking program. See: Executive Order No. 13,777, Enforcing the Regulatory Reform Agenda (Feb. 24, 2017); and Executive Order No. 13,771, Reducing Regulation and Controlling Regulatory Costs (Jan. 30, 2017).

If EPA accepts the premise that it should retrospectively review its past rulemaking to improve its future efforts, the opportunity to do so is here, right now. Among the lessons that EPA should draw from the rules that were vacated in the cases cited above are that: EPA has become poor at promulgating them; EPA tends to undervalue rulemaking comments showing that EPA's proposal was suboptimal, unreasonable or otherwise unlawful; and EPA has difficulty correctly predicting the future, and, in particular, the courts' likely response to its rulemaking efforts.

No one should lose sight of the fact that, although EPA was the losing party in the cases cited above, the decisions found to be unreasonable were made by individuals; people, not an abstraction, were responsible for the actions that were found to be unlawful. Consequently, the solution in this rulemaking will lie in either those people substantially improving their performance (which, to me, seems unlikely), or by having others in EPA give less weight to the opinions of the people responsible for those mistakes, and greater weight to those whose better advice was rejected, if it was sought at all.

It is implausible that EPA's scientists, engineers, lawyers and other career staff lost their skill collectively, simultaneously, and coincidently with the change of Administration in January 2017. Something did change, however: the arrival of the Administration's political appointees. [23] It is the consequences of that change that should be addressed if this rulemaking is going to achieve a result different from the injunctions and remands ordered by the courts in the cases cited above.

Although the unpleasant situation now at EPA has received substantial press coverage (and the EPA staff members reading this comment probably need little reminding), there is a particular article that I request that EPA make part of this rulemaking record and consider in its deliberations: Tollefson J, Science under siege, Nature 559:316-319 (July 19, 2018).[24] When what is likely the world's leading multidisciplinary science journal publishes an article with the subtitle "Uncertainty, hostility and irrelevance are part of daily life for scientists at the US Environmental Protection Agency", EPA's senior managers should neither ignore it nor deny that they need to make substantial changes.

Since the Supreme Court decided Daubert, hundreds of published opinions have identified "the known or potential rate of error" as an appropriate criterion to determine if a court should give any weight at all to testimony offered on a scientific matter.[25] In this rulemaking, analogous criteria should apply when EPA determines what weight it gives the views of the political appointees whose contributions led to the decisions analyzed above.

EPA should also recognize that the knowledge that the public gained, and that EPA should gain, from the agency's failed rulemakings did not come cheaply; neither EPA's rulemaking, nor the litigation proving that the outcome of those efforts was unlawful, was inexpensive. EPA should not now compound the problem in this rulemaking by squandering that knowledge, or by refusing to change its culture of decision-making in the face of that knowledge.

I also urge that EPA agree that the errors for which it is responsible in the above cases were not symmetrical. Its errors did not occasionally benefit regulated industries, while sometimes overly protect public health and the environment. EPA's performance has not been that of an imperfect, but unbiased, umpire, sometimes miscalling balls and strikes, but not intentionally favoring one side. Rather, EPA's errors are not random; their pattern reveals a purpose. In each of the above cases, EPA sought to reduce the health and environmental benefits that the public has secured for itself under current law, and EPA used an unlawful method to do so.[26]

EPA should evaluate the comments supporting its proposal, as well as the comments opposing its proposal, in light of past performance. EPA should, in particular, consider the harm to the public when governmental agencies such as EPA gave insufficient weight to comments supporting action to protect public health, and unwisely relied on comments opposing that action.

The processes by which the Federal Government and the States determine how best to serve the public involve participants who are now highly polarized.[27] Those polarized participants include the officials who make the decisions, as well as interested parties who are often repeat players. The polarization of those parties has created obstacles to good governmental decision making, but there are some consequences of polarization and repeat play that are helpful: they provide information regarding past performance that EPA should not ignore in this proceeding.

I believe that the following statements regarding the comments that EPA will receive in this rulemaking are uncontroversial:

1. Many of the comments in this rulemaking will be from repeat players -- e.g., regulated companies, industry groups, public health organizations, environmental groups, and other

interest groups – with previous experience in administrative proceedings or the legislative process;

2. those comments will be of a type typically submitted by repeat players: i.e., the commenter offers its prediction that, if the agency adopts Option A, the public will be better served than if the agency adopts Option B, and the commenter provides analysis supporting its prediction; and
3. the predictions will differ, substantially and unsurprisingly, depending upon whether the commenter is a regulated company or industry group, on the one hand, or a public health organization or environmental group, on the other.

Said another way, many of the comments received will be from interested parties with a history of giving government officials predictions regarding how best to advance the public interest, and offering those predictions for the purpose of influencing governmental decisions.[28]

Obviously, the weight that any government official will give to the differing predictions submitted will vary. Collectively, however, an administrative agency's or legislator's response to competing analyses is far from unpredictable. Administrations and legislators have track records. In fact, it is a government official's predictability that allows interest groups to make and use scorecards and rankings of those officials, to identify those officials mostly likely to be receptive to the group's analyses, and to identify those most likely to be skeptical of them. [29]

A quick scan of those scorecards and rankings confirms the conclusion that virtually any participant in this rulemaking has already reached: predictions given to agencies and legislatures are heard by different audiences depending on whether the administration or legislature is Republican- or Democratic- controlled; and those differences have consequences. All should expect that analyses of the kind offered by the proponents of EPA's current proposal (or an even more lenient alternative) will be found to be more persuasive, and will receive greater weight, by officials in States with Republican administrations and Republican-controlled legislatures. Likewise, we should be unsurprised that predictions indicating that such a proposal is too lenient will be viewed more skeptically and given lesser weight by the officials in those States.[30]

To me, that officials in Red States and Blue States weigh predictions regarding regulatory activity differently seems undeniable, particularly in the area of public health interventions and the area of environmental protection. Those are two areas in which the polarization among the States is most evident.

Whether the differences between Red States' and Blue States' methods for evaluating predictions regarding public health and environmental protection has gotten too large may be debated. However, the fact that there are differences should not be ignored. The choices that each State made when it determined to rely on a prediction that appeared to be persuasive, and rejected or gave less weight to conflicting predictions because they seemed inferior, when coupled with the subsequent outcomes to the State's citizens, provide evidence by which we can determine whose predictions were, in fact, more accurate. After all, if a government generally gives greater weight to the predictions that turn out to be most accurate, and discounts the predictions that are less so, we should expect its citizens to enjoy some kind of observable benefit. Likewise, if a government habitually rejects the more accurate predictions, and relies on poorer predictions instead, we should expect that its citizens will bear poorer outcomes.

Accordingly, if there are substantial differences in the public health outcomes of Americans, and those differences can be predicted by living in a Red State versus a Blue State, those differences suggest that one of those groups of States is better at recognizing accurate predictions, and acting upon them, than the other group. Further, if there are substantial differences in the public health outcomes of Americans, and those differences can be predicted by living in a Red State versus a Blue State, the practices of the more successful States should be emulated, not ignored.

Simply put, when evaluating the conflicting predictions in the comments in this proceeding, I urge that EPA not ignore useful evidence for identifying those predictions which are reliable, and those which are not: past performance.[31] EPA should not blindly guess which predictor will do a better job of predicting actions that will benefit the public. Identifying those actions and selecting among them is EPA's, and each State's, core responsibility, each of them are repeat players, and their past performance can be compared.

From the scientific literature, we now have studies that answer the two important questions referenced above: Can knowing which political party governs a state help predict the public health and welfare outcomes of the people living there?; and, if so, which party is associated with the better outcomes? And the answers are: yes; and Democratic.

Unquestionably, the repeat players supporting this proposal -- as well as their allied conservative interest groups -- have enjoyed much success, particularly in Red States, the areas where legislators and administration officials find their predictions to be most persuasive. But the more critical question is: What happened to the citizens in those States as a result of their governmental officials' reliance on those predictions: Did the public at large share in that success, as those interest groups surely predicted as they sought to influence those officials? Likewise, what has happened to the citizens in Blue States, the jurisdictions more skeptical of conservative interest groups' rosy predictions? [32] The answers to those questions will inform EPA regarding how much, and upon whom, it should rely when evaluating the conflicting predictions in this rulemaking. Fortunately, that information is available to EPA, and ignoring that information would be unreasonable.

Accordingly, I urge that EPA consider the following studies:

Fenelon A, Geographic divergence in mortality in the United States, *Population and Development Review* 39(4):611-634 (2013)[33] (reviewing analyses of mortality rates among the various States; finding that the gaps between the well- and poor- performing States are widening; and stating:

"Along with varying mortality levels, regions within the US also have vastly different experiences in terms of environmental exposures, disease control, medical treatment and care, and behavioral risk …. Since the mid-twentieth century, the sections of the US with particularly high mortality have become increasingly concentrated in space and clustered in the South. The standard South US census region includes all states south of the Mason–Dixon line and westward to Texas and Oklahoma. The most disadvantaged region of the South is the so-called Central South, containing Alabama, Kentucky, Mississippi, and Tennessee. This region is distinctive for experiencing a large health and mortality disadvantage as well as relatively high poverty …. …. In the early to mid-2000s, adult mortality rates in many southern states were 30-40 percent higher than top performers in other regions, particularly the Pacific Coast, Upper Midwest, and New England. This excess mortality translates into 3–4 fewer expected years of life at age 50 for the states that are worst off.", id., at 611-612 (cites and footnote omitted);

"The public health and epidemiological literatures contain a multitude of studies demonstrating poorer health and mortality outcomes in the southern US, a pattern that is observed with respect to many measures of health and well-being …. The large literature on the 'stroke belt' indicates the extent to which specific cardiovascular diseases are especially concentrated in this region …. Although the southern disadvantage characterizes most states in the South census region, the phenomenon is particularly focused in the Central South: Alabama, Kentucky, Mississippi, and Tennessee.", id., at 612-613 (cites omitted);

"Gaps in adult mortality between the southern states and better-off states in the Northeast, Midwest, and West have widened considerably.", id., at 613;

"Although the prevalence of smoking has declined in all states, southern states, particularly Kentucky, have maintained high levels of smoking while other states, especially those in the West, have kept smoking prevalence relatively low over the past several decades …."; id., at 615 (cite omitted);

"New England and Middle Atlantic states exhibit mortality declines that are 75– 90 percent larger over this period compared to the Central South.", id., at 621;

"Obesity may be another piece of this puzzle, given that the impact of widespread obesity has been larger in southern states ….", id., at 626 (cite omitted);

"Conclusion There has been an increasing concentration of health and mortality disadvantage in the American South since the mid-twentieth century. States with the least favorable mortality trajectories during this period were located almost exclusively in the South, while states in the Northeast, Upper Midwest, and West performed relatively well. The poorest-performing southern states were Alabama, Kentucky, Louisiana, Mississippi, and Tennessee. This process reflects a wider trend of diverging mortality experience among regions within the US, with gaps between the South and more-advantaged parts of the country growing to more than 30 percent in the mid-2000s. Declines in all-cause mortality between 1965 and 2004 were rather small in southern states; slowdowns occurred first for men and later for women, a trend also observed at the national level …. In contrast to the Healthy People 2020 goal of eliminating health and mortality disparities based on geographic location, the past 40 years have seen a substantial widening of geographic disparities in mortality.", id., at 627-628 (cite omitted); and "During the period considered here, in which the South fell behind much of the rest of the United States, the

US as a whole also fell behind much of the rest of the developed world. …. The slowed progress against mortality in the southern United States is not unlike the unfavorable health and mortality experience of Eastern Europe over the past three decades …", id., at 629 (cite omitted));

James W, Cossman J, Wolf J, Persistence of death in the United States: The remarkably different mortality patterns between America's Heartland and Dixieland, Demographic Research 39:897-910 (2018)[34] (addressing mortality rates among the various States; concluding that the gap between well- and poor performing States continues to grow; and stating:

"Findings support the hypothesis that persistently high mortality places are disproportionately concentrated in the rural South, particularly the East South Central division of Kentucky, Tennessee, Mississippi, and Alabama.", id., at 897;

"The divergence between the southern rate and the urban reference category increases in each time period. While the disparity was only about 50 deaths per 100,000 in the late 1960s, it has increased to an alarming 100 deaths per 100,000 in the mid-2010s.", id., at 902;

"While the rural [East South Central census division] has always been at a mortality disadvantage, it has been exacerbated in recent years. …. …. For decades, urban America has improved its mortality faster than other parts of the country, decreasing its collective mortality rate by 5% annually. Rural America registers a slightly slower rate of improvement of 4.5%. However, when examining rural divisions, it is evident that the rural US mortality penalty is fueled by conditions in the South. In particular, the rural WSC and rural ESC divisions lag considerably behind in mortality improvement, at 3.3% and 2.9% respectively.", id., at 903; and

"We conclude by answering the original question; what place has it the worst and how bad is it? The rural parts of the South Central states have it the worst, by a landslide.", id., at 906);

Mokdad AH, Ballestros K, Echko M, Glenn S, Olsen HE, Mullany E, Lee A, Khan AR, Ahmadi A, Ferrari AJ, Kasaeian A, The state of US health, 1990-2016: Burden of diseases, injuries, and risk factors among US states, JAMA 319(14):1444-1472 (2018)[35] (assessing the varying prevalence of disease and differing life expectancies among the States; finding that "There are wide differences in the burden of disease at the state level.", id., at 1444; noting that the disparities are increasing; and identifying high- and low-performing States:

"Previous studies have reported on health disparities in US states and counties. These studies showed that health disparities have increased with time. ....

Several studies have shown large variations in risk factors by state and county, and these variations have contributed to differences in health outcomes.", id., at 1445;

"Life Expectancy and HALE

Life expectancy and HALE ["healthy life expectancy'] at birth for both sexes combined for the United States, all 50 states, and for Washington, DC are shown in Table 3. Hawaii had the highest life expectancy at birth in 2016 (81.3 years [95% UI, 80.6 to 81.9]), while Mississippi had the lowest (74.7 years [95% UI, 73.5 to 76.1]; a 6.6-year difference). Other states with high life expectancy were California (80.9 years [95% UI, 79.9 to 81.9]), Connecticut (80.8 years [95% UI, 79.7 to 81.8]), Minnesota (80.8 years [95% UI, 80.0 to 81.6]), New York (80.5 years [95% UI, 79.4 to 81.6]), Massachusetts (80.4 years [95% UI, 79.6 to 81.1]), Colorado (80.2 years [95% UI, 79.4 to 80.9]), New Jersey (80.2 years [95%UI,79.3 to 80.9]), and Washington (80.2 years [95% UI, 79.5 to 80.8]). Other states with low life expectancy were West Virginia (75.3 years [95% UI, 74.4 to 76.0]), Alabama (75.4years [95% UI, 74.1 to 76.7]), Louisiana (75.6 years [95% UI, 74.9 to 76.4]), Oklahoma (75.7 years [95% UI, 75.0 to 76.4]), Arkansas (75.8 years [95% UI, 74.9 to 76.8]), and Kentucky (75.8 years [95% UI, 74.9 to 76.6]). In 2016, Minnesota had the highest HALE at birth with 70.3 years, while West Virginia had the lowest at 63.8 years, a 6.5-year difference.", id., at 1449-1450;

"Table 6 presents the age-standardized death rates, age-standardized YLL ["years of life lost'] rates, and age-standardized YLD ["years lived with disability'] rates in 1990 and 2016 and their ranks by state. The 3 measurements varied widely between the states in 2016, ranging from 767.6 deaths per 100000 in Mississippi to 465.8 deaths per 100000 in Hawaii, from 17775.9 YLLs per 100000 in Mississippi to 9901.8 YLLs per 100000 in Minnesota, and from 13090.6 YLDs per 100000 in West Virginia to 10582.8 YLDs per 100000 in Minnesota. A notable improvement was observed in Washington, DC (decreases from 1042.7 deaths per 100000 to 603.3 deaths per 100000, from 29536.9 YLLs per 100000 to 13635.9 YLLs per 100000, and from 12230.8 YLDs per 100000 to 11421.1 YLDs per 100000) and in California (decreases from 719.1 deaths per 100000 to 491.7 deaths per 100000, from 15903.4 YLLS per 100000 to 9987.0 YLLs per 100000, and from 11170.5 YLDs per 100000 to 10990.4 YLDs per 100000). …. The age-standardized death rates and age-standardized YLL rates declined in all states, but the level of decline for deaths ranged from 6.3% in Oklahoma to 42.1% in Washington, DC and the level of decline for YLLs ranged from 4.0% for Oklahoma to 53.8% for Washington, DC. Age-standardized YLD rates increased by 4.4% for West Virginia and declined by 6.6% for Washington, DC.", id., at 1450-1451; and

"The largest reductions in probability of death for ages 20 to 55 years were observed in New York (3.5) and California (2.5) and the highest increases were observed in West Virginia (2.6) and Oklahoma (2.0) (Figure 4). In 21 states, the probability of death has actually increased from 1990 to 2016 ….", id., at 1456);

Elo IT, Hendi AS, Ho JY, Vierboom YC, Preston SH, Trends in non-Hispanic white mortality in the United States by metropolitan-nonmetropolitan status and region, 1990– 2016, Population and Development Review 45(3):549 (2019)[36] (examining differing – and widening -- mortality rates among the States; and stating:

"Mortality improvements in Appalachia and the South, particularly the East South Central Division, have lagged behind other regions (Fenelon 2013; Wang et al. 2013), a pattern that has been partly linked to behavioral risk factors such as smoking and obesity (Fenelon 2013; Singh and Siahpush 2014; Dwyer-Lindgren et al. 2016; Dwyer-Lindgren et al. 2017; Mokdad et al. 2017; Roth et al. 2017).";

"Table 2 presents changes in life expectancy between 1990 and 2016 by metrononmetro status. ….. It is clear from Table 2 that the United States has experienced growing geographic inequality in life expectancy gains for white men and women over this period. This divergence has been driven by more rapid increases in life expectancy in large central metros and slower improvements elsewhere. White male life expectancy increased 5.09 years in large central metros, compared to 3.45 years in large metro suburbs, 2.81 years in small/medium metros, and 2.25 years in nonmetro areas. Large central metros are now among the areas with the highest white male life expectancy in the country. This ascendance is particularly noteworthy because large central metros had the lowest life expectancy levels in 1990–1992. The gain in large central metros was 2.3 times greater (5.09/2.25) than that in nonmetro areas, which had the second lowest life expectancy levels in 1990–1992.

Among white women, life expectancy differences by metro-nonmetro status were relatively small in 1990–1992. However, by 2014–2016, substantial variation emerged, with the largest gains recorded in large central metros (2.98 years), followed by large metro suburbs (2.23 years), small/medium metros (1.24 years), and nonmetro areas (0.20 years) (Table 2). These differences are particularly striking for large central metros compared to nonmetros, with gains in white female life expectancy that were 14.9 times greater (2.98/0.20) in large central metros than in nonmetro areas.

…. Between 2009–2011 and 2014–2016, large central metros and large metro suburbs continued to experience gains in life expectancy, but small/medium metros and nonmetros experienced life expectancy declines. Thus, while the metrononmetro gradient widened between 1990–1992 and 2009–2011 due to quicker gains among large central metros, the gradient has since widened due to a combination of gains in large metros and their suburbs and declines in small/medium metros and nonmetro areas.";

"... the Middle Atlantic and Pacific regions stand out as having particularly rapid life expectancy gains for white men in large central metros, on the order of 7.13 and 6.11 years, respectively. White men in nonmetro areas of the Appalachian, East South Central, and West South Central regions experienced the smallest gains, amounting to 1.42–1.80 years.

A similar pattern is observed for white women, with the largest gains occurring in large central metros in the Middle Atlantic (4.66 years) and Pacific (4.00 years) regions. Nonmetro areas experienced the smallest gains in female life expectancy, especially in the East North Central, West North Central, and South Atlantic regions, with actual declines in life expectancy observed in nonmetro areas of the Appalachian, East South Central, and West South Central regions.

In all 40 areas, white men's life expectancy gains outpaced white women's life expectancy gains. If we compare the best-performing region/metro category/sex combination to the worst-performing combination, men in large central metros in the Middle Atlantic gained 7.13 years of life expectancy during this period whereas women in nonmetros in the West South Central and East South Central regions lost nearly a year in life expectancy between 1990–1992 and 2014–2016.

…. ... large central metros outperformed nonmetros within the Appalachian and East South Central regions." and

"Over the last quarter century, we have witnessed growing geographic inequalities in mortality in the United States. Two notable features of the last 25 years are the sizable increase in life expectancy in large central metros and the slow improvement or decline, especially among women, in nonmetro areas. For the United States as a whole, white male life expectancy at birth in large central metros increased by 5.09 years between 1990–1992 and 2014–2016; the comparable figure for white women was 2.98 years. In contrast, nonmetro areas experienced the smallest life expectancy gains: 2.25 years among white men and only 0.20 years among white women. This pattern of larger increases in life expectancy in large central metros and small or negligible increases or even declines in nonmetro areas was pervasive in all 10 regions of the country examined in these analyses.");

Crimmins EM, Zhang YS, Aging populations, mortality, and life expectancy, Annual Review of Sociology 45:69-85 (2019) (finding:

"In recent years, urban-metropolitan areas experienced larger increases in life expectancy than those in nonmetropolitan counties, contributing to widening urban– rural disparities in life expectancy (Singh & Siahpush 2014).

Regions of the country have also experienced different trends. Places with high mortality rates are concentrated in the central southern states, including Alabama, Kentucky, Mississippi, and Tennessee; this southern disadvantage has been growing over time (Fenelon 2013a). Wang et al. (2013) examine changes in life expectancy by county from 1985 to 2010, finding that some counties in New York, Virginia, California, and Colorado gained more than nine years in life expectancy for men and more than six years for women, whereas the counties that experienced decreases in life expectancy were concentrated in Oklahoma, Kentucky, Mississippi, and Alabama. …. The counties without gains in life expectancy are also concentrated in southern and rural states.

…. From 1980 to 2014, 160 counties experienced significant increases in cancer mortality; the highest rates of increase were in Kentucky and other southern states (Mokdad et al. 2017). Counties in Kentucky, West Virginia, Ohio, Indiana, and eastern Oklahoma have experienced the greatest increases in mortality from drug-use disorders in recent decades (Dwyer-Lindgren et al. 2018).");

Wang H, Schumacher AE, Levitz CE, Mokdad AH, Murray CJ. Left behind: Widening disparities for males and females in US county life expectancy, 1985–2010, Population Health Metrics 11(1):8 (2013) (analyzing the geographic disparities in life expectancy, and concluding:

"Some general patterns are evident. In all time periods, the lowest life expectancies are seen in the South, the Mississippi basin, West Virginia, Kentucky, and selected counties in the West and Midwest that have large Native American reservation populations.", id., at 3; and

"Ten of the worst-performing counties for females (with declines in life expectancy) were in Oklahoma, and five were in Kentucky. For males, the worst performers were in Kentucky, Oklahoma, Mississippi, and Alabama.", id., at 5);

Heisler EJ, The US Infant Mortality Rate: International Comparisons, Underlying Factors, and Federal Programs, Congressional Research Service, Report to Congress (2012) (describing the variation in infant mortality rates ("IMRs") among the States, and finding:

"Geographic Variation in U.S. Infant Mortality

There is large variation in IMRs among U.S. states. ….

…. Infant mortality rates are generally highest in the southern states, including Mississippi, Alabama, and Louisiana. The higher IMRs in these states may be explained, in part, by demographic and health system characteristics of these states. For example, southern states have high poverty and uninsurance rates. The opposite is generally true in states with low IMRs, such as those in the New England and the Pacific Northwest.", id., at 9 (footnotes omitted); and

"The U.S. IMR also varies geographically. In general, southern states have the highest IMRs and states in the West and in New England have the lowest.", id., at 29);

Roth GA, Johnson CO, Abate KH, Abd-Allah F, Ahmed M, Alam K, Alam T, AlvisGuzman N, Ansari H, Ärnlöv J, Atey TM, The burden of cardiovascular diseases among US states, 1990-2016, JAMA Cardiology 3(5):375-389 (2018) (addressing the large variation in prevalence of cardiovascular disease – and in the rate of change in cardiovascular disease prevalence -- among the States:

"Cardiovascular disease (CVD) is the leading cause of death in the United States, but regional variation within the United States is large.", id., at 375;

"Cardiovascular disease (CVD) was the leading cause of death in the United States in 2016, accounting for more than 900000 deaths. Despite large declines in CVD mortality in the late 20th century attributed to advances in public health and health care, improvements in US life expectancy have slowed for some groups, and CVD mortality is no longer improving. The strongest signal for this alarming trend in US health is identified subnationally at the state and county level, where levels of risk exposure and health vary widely.", id., at 376 (footnotes omitted);

"RESULTS Between 1990 and 2016, age-standardized CVD DALYs ["disability adjusted life-years'] for all states decreased. Several states had large rises in their relative rank ordering for total CVD DALYs among states, including Arkansas, Oklahoma, Alabama, Kentucky, Missouri, Indiana, Kansas, Alaska, and Iowa. The rate of decline varied widely across states ....", id., at 375; [37]

"Several states had large rises in their relative rank ordering for total CVD DALYs among states, including Arkansas, Oklahoma, Alabama, Kentucky, Missouri, Indiana, Kansas, Alaska, and Iowa (Figure 1).", id., at 377;

"Change in Total CVD Burden, 1990-2016

The age-standardized rate of CVD DALYs decreased significantly in all states between 1990 and 2016, but there was wide regional variation in the amount of this decline …. The largest percentage change occurred in the District of Columbia, New Hampshire, and New York. The rate of decline varied by sex, with a slower decline for women than men in all states …. The slowest decline was observed for women in Oklahoma, Arkansas, and Alabama. Total CVD burden increased for both men and women from 2010 to 2016 in Indiana, Kentucky, Michigan, Mississippi, Missouri, New Mexico, and South Dakota.

Geographic Variation in Total and Cause-Specific CVD Burden in 2016

There was wide geographic variation in the age-standardized CVD burden among US states in 2016, with the greatest burden concentrated in a band of states extending from the Gulf Coast to West Virginia. The highest rate of CVD DALYs was in Mississippi (4982 age-standardized DALYs per 100000 persons; 95% UI, 4475- 5487), followed by Arkansas, Oklahoma, Louisiana, Alabama, Tennessee, Kentucky, West Virginia, South Carolina, and Georgia (Table). Notably, several states outside this region had levels of CVD DALYs nearly as high, including Indiana, Missouri, Ohio, Michigan, North Carolina, Nevada, and Texas. The lowest rate of CVD DALYs was in Minnesota (2352 age-standardized DALYs per 100000 persons; 95% UI, 2148-2552), followed by Colorado and areas of New England and the Pacific Northwest, including Massachusetts, New Hampshire, Washington, Connecticut, Vermont, and Oregon.", id., at 378;

"States with the highest burden of CVD in 1990, such as Kentucky, West Virginia, Alabama, Arkansas, Louisiana, Tennessee, and Oklahoma, are only now achieving the 1990 levels of CVD burden in Massachusetts, Connecticut, and New Jersey. Mississippi continues to lag as the state with the largest CVD burden in the United States. These findings support the idea that tremendous gains in cardiovascular health are possible even in states with lower socioeconomic levels but that relative disparities between states have changed very little. These relative disparities may be of particular concern for Alabama, Mississippi, Oklahoma, and Tennessee, given their recent decision to not expand their respective Medicaid systems.", id., at 383 (footnotes omitted); and

"We found that CVD burden has improved for all states, but the rate of decline varies widely and is strongly associated with an index of socioeconomic level. For 12 states, CVD burden has increased since 2010.", id., at 387);

Fang J, Yang Q, Hong Y, Loustalot F, Status of cardiovascular health among adult Americans in the 50 States and the District of Columbia, 2009, Journal of the American Heart Association 1(6):e005371 (2012)[38] (reporting, at Figure 2, an "adjusted prevalence ratio of ideal cardiovascular health' for each State; with, by my reckoning, each of the 18 worst performing States being Red States);

Flavin P, State Medicaid expansion and citizens' quality of life, Social Science Quarterly 99(2):616-625 (2018) (reporting measurements of subjective well-being of residents of States that expanded their Medicaid program, compared to residents of States that did not expand the program, after the Supreme Court's 2012 decision in National Federation of Independent Business v. Sebelius; as follows:

"Objectives. The U.S. Supreme Court's 2012 ruling on the Affordable Care Act was a federal exogenous shock that presented all states with the decision to continue their Medicaid program in its current form or expand it to include thousands of newly eligible recipients. This article takes advantage of this exogenous shock to evaluate the impact of Medicaid expansion on citizens' quality of life. Methods. I evaluate changes from 2010 to 2014 in low-income citizens' subjective well-being (SWB) using Gallup-Healthways survey data and a difference-in-differences estimation strategy. Results. Average levels of SWB increased among low-income citizens in states that expanded Medicaid eligibility compared to states that did not. …. Conclusions. The empirical findings suggest that the expansion of Medicaid has important implications for the well-being of low-income Americans and, more broadly, contribute to the growing literature on how government policy choices can concretely impact the quality of life that citizens experience.", id., at 616;

"Specifically, using a difference-in-differences estimation strategy, I compare changes in subjective well-being (SWB) among low-income citizens in states that did and did not expand Medicaid in 2014 (the first year federal money funded the expansion). After accounting for changes in state economic conditions, I find consistent evidence that SWB increased among low-income citizens in states that expanded Medicaid eligibility compared to states that did not. To address concerns about spuriousness, I also conduct a series of placebo tests and demonstrate that the expansion had no effect on the SWB of middle- or high-income citizens who are unlikely to directly benefit from more generous Medicaid eligibility requirements. Together, these findings suggest that the expansion of Medicaid can have important effects on the well-being of low-income Americans and, more broadly, contribute to the growing literature on how government policy choices concretely impact citizens' quality of life. ….

…. … because of the Supreme Court's ruling that states have the power to choose to expand or not without risking their existing federal funding, there is now significant variation in Medicaid eligibility across states. This variation allows, from a policy analysis standpoint, the chance to evaluate the real-world effects of state government policy choices.", id., at 617;

"Similarly, early analysis of the direct effects of Medicaid expansion under the ACA also finds that citizens express higher levels of self-reported health and are less likely to have their activities limited by poor health in states that expanded Medicaid compared to people living in states that did not expand the program (Sommers et al., 2015). In sum, across a wide array of health indicators, there is evidence that Medicaid expansion has positive effects for health outcomes among citizens.", id., at 618; and

"As the analysis above documents, citizens with low incomes reported a greater boost in SWB in states that decided to expand Medicaid eligibility when compared to low-income citizens living in states that chose not to expand.", id., at 623);

Grumbach JM, From backwaters to major policymakers: Policy polarization in the States, 1970–2014, Perspectives on Politics 16(2):416-435 (2018) (noting the sharp polarization of health and welfare policies among the States, addressing the differing percentages of persons covered by health insurance among them, and the consequences for residents of States with low rates of coverage:

"party control increasingly predicts socioeconomic outcomes in the polarized area of health care", id., at 416;

"Health and welfare policy has sharply polarized in recent years, and I find that party control of state government increasingly predicts rates of health insurance coverage.", id., at 417;

"But does this policy polarization matter for the lives of these states' residents? Does it matter for socioeconomic outcomes that there is polarization in 14 issue areas, such as tax and health policy, but non-polarization in criminal justice and education? In the next section I provide evidence that it does. In the polarized area of health policy, party control of state government increasingly predicts rates of health coverage. ….

The Socioeconomic Consequences of Policy Polarization

The polarization of policy carries major socioeconomic consequences for residents. In the polarized areas of health and environmental policy, party control of state government increasingly predicts rates of health coverage and carbon intensity of a state's energy supply, respectively.", id., at 423-424;

"The health policy agendas of the national Democratic and Republican parties have been distinct since at least the 1930s. Health policy in the states has been similarly polarized for decades, as Democratic states tended to have more generous Medicaid eligibility and benefits. As the role of states in health policy expanded with the development of state prescription drug benefits for seniors, as well as federal grants for the State Children's Health Program (1998) and Medicaid expansion under the Affordable Care Act (2014), state health policies increasingly varied -- and this variation was increasingly related to party control of government.", id., at 425; and

"… party control of government is increasingly associated with health insurance coverage in more recent years. Whereas prior to 2000, party control does not predict change in the uninsured rate, after 2000 unified Republican control is associated with a 0.75 percentage-point increase in the uninsured rate and unified Democratic control is associated with a 0.75 percentage-point decrease in the uninsured rate. These differences in coverage are of considerable social consequence. Health policy scholars, for instance, 'estimate the number of deaths attributable to the lack of Medicaid expansion in opt-out states at between 7,115 and 17,104.'", id., at 426 (footnote omitted));

Van Dyke ME, Komro KA, Shah MP, Livingston MD, Kramer MR, State-level minimum wage and heart disease death rates in the United States, 1980–2015: A novel application of marginal structural modeling, Preventive Medicine 112:97-103 (2018) (addressing the association between a State's minimum wage and its death rate due to heart disease; reviewing past studies regarding the association between a State's minimum wage and infant mortality; and finding:

"This study examined the association between state-level minimum wage increases above the federal minimum wage and heart disease death rates from 1980 to 2015 among 'working age' individuals aged 35–64 years in the US. …. In models of 'working age' adults (35–64 years old), a \$1 increase in the state-level minimum wage above the federal minimum wage was on average associated with ~6 fewer heart disease deaths per 100,000 (95% CI: −10.4, −1.99), or a state-level heart disease death rate that was 3.5% lower per year. In contrast, for older adults (65+ years old) a \$1 increase was on average associated with a 1.1% lower state level heart disease death rate per year (b = −28.9 per 100,000, 95% CI: −71.1, 13.3).";

"A study examining the association between state minimum wage laws in the US and low birth weight and infant mortality from 1980 to 2011 found that every dollar increase in the state-level minimum wage above the federal minimum wage was linked with a 1–2% decrease in low birth weight and a 4% decrease in infant mortality (Komro et al., 2016). Another study spanning 25 years found that increases in the state minimum wage were associated with increases in birth weight, increases in prenatal care use, and declines in smoking during pregnancy (Wehby et al., 2016). A simulation study of the impact of a hypothetical increase in the minimum wage in New York City on premature mortality found that a \$15 minimum wage may avert 4 to 8% of premature deaths, with most of the avoidable deaths being among lower-income communities consisting of primarily racial minorities (Tsao et al., 2016).";

"This ecologic study aims to describe the association between state-level minimum wage increases above the federal minimum wage and heart disease death rates from 1980 to 2015 in the US.";

"Region-specific descriptive summaries of state-level minimum wage, socioeconomic measures, and heart disease death rates for 1980 and 2015 are provided in Table 1 and Fig. 1. In 1980, average minimum wage values (in 2015 dollars) were similar across US regions at \$8.94–\$8.95. However, in 2015, there was greater variation -- Northeastern states had the highest average minimum wage value at \$8.40, and Southern states had the lowest average minimum wage value at \$7.61.";

"… we see that each \$1 increase in the minimum wage is associated with a significant 3.5% decline in heart disease deaths for working age adults, and with a non-significant 1.1% decline for those 65 and older.";

"In the current study, increases in the state-level minimum wage above the federal value were associated with a reduction in heart disease death rates among individuals aged 35–64 years. The inverse associations between state-level minimum wage increases above the federal minimum wage and state-level heart disease death rates are consistent with research documenting the importance of economic policy for health (Leigh, 2016; Wehby et al., 2016), and more specifically of minimum wage policy for health (Bullinger, 2017; Komro et al., 2016; Tsao et al., 2016; Wehby et al., 2016).";

"Additionally, Kuroki (2017) observed an increase in life satisfaction among workers with less than a high-school diploma as state minimum wages increased from 2005 to 2010, and Lenhart (2017b) found a reduction in smoking, drinking, and body weight following an increase in the minimum wage specifically among lower educated individuals from 1989 to 2015."; and

"5. Conclusion

Inter-state variation in social and economic policies represent opportunities for leveraging natural experiments to understand population health consequences. In this study examining the association between the state-level minimum wage and heart disease death rates in the US among individuals aged 35–64 years from 1980 to 2015, increases in the state-level minimum wage above the federal value were associated with a reduction in heart disease death rates. This association persisted in time-lag models and was largely absent in a negative control population, adults over 65 years of age. The study of intended and unintended consequences of social and economic policy is complex, but the findings from this study are consistent with positive health consequences of increases in the minimum wage among working age individuals in the US. Moreover, this study provides an example of the utility of marginal structural modeling vs. conventional regression methods when time-varying confounding is a potential concern. This contributes to a small but growing body of literature characterizing population health consequences of a higher minimum wage.");

Olives C, Myerson R, Mokdad AH, Murray CJ, Lim SS, Prevalence, awareness, treatment, and control of hypertension in United States counties, 2001–2009, PloS one 8(4):e60308 (2013) (analyzing the geographic disparity in the prevalence of hypertension, and finding:

"Total hypertension prevalence exhibited strong geographic trends, with the heaviest burden localized to southeastern states (Figure 1). .... These trends were even more pronounced when considering prevalence of uncontrolled hypertension (Figure 1), where counties with elevated burden were almost entirely localized to southeastern states, with the exception of a few counties in the Four Corners area and in South Dakota.", id., at 5; and

"we found that in certain high-prevalence counties in the south, almost 50% of individuals reported taking antihypertensive medication in 2009.", id., at 6);

Arnett DK, Divided States of America: Regional variation in cardiovascular health, Journal of the American Heart Association 1:e006114 (2012) (reporting age-standardized scores of individual cardiovascular health metrics by state);

Blackley D, Zheng S, Ketchum W, Implementing a weighted spatial smoothing algorithm to identify a lung cancer belt in the United States, Cancer Epidemiology 36(5):436-438 (2012) (describing the location of a "lung cancer belt" within the United States, and the consequences for those Americans living within it:

"Upon generating a county-level map of the continental United States (Fig. 1), we observed an area of high lung and bronchus (hereafter, lung) cancer mortality rates, primarily in the southeastern United States.", id., at 436; and

"Fig. 2 depicts a multi-state area of high lung cancer mortality, comprising 724 counties and forming an arc that was not evident in the unsmoothed data. This area, which we define as the lung cancer belt, includes nearly all of Arkansas, Kentucky and Tennessee, as well as portions of 16 other states. Heavily affected regions include much of the Ohio Valley, Central Appalachia, the Tennessee Valley, the Ozarks, the Mississippi Delta and the northern Gulf Coast. All counties within the lung cancer belt had a smoothed age-adjusted lung cancer mortality rate at or above 64 deaths per 100000 compared to a rate of 51.6 deaths per 100000 for the entire United States during the same time period.", id., at 437);

Cunningham SA, Patel SA, Beckles GL, Geiss LS, Mehta N, Xie H, Imperatore G, County-level contextual factors associated with diabetes incidence in the United States, Annals of Epidemiology 28(1):20-25 (2018)[39] (describing a "diabetes belt", "concentrated primarily in 644 counties within 15 southern states", with a prevalence of diabetes that is 40% higher compared to the average of all other U.S. counties);

Barker LE, Thompson TJ, Kirtland KA, Boyle JP, Geiss LS, McCauley MM, Albright AL, Bayesian small area estimates of diabetes incidence by United States county, 2009, Journal of Data Science 11(1):269-280 (2013) [40] (with similar findings);

Barker LE, Kirtland KA, Gregg EW, Geiss LS, Thompson TJ, Geographic distribution of diagnosed diabetes in the US: A diabetes belt, American Journal of Preventive Medicine 40(4):434-439 (2011) (describing America's "diabetes belt", as well as the Nation's "stroke belt", and the difference in the prevalence of the disease in it, as follows:

"The American "stroke belt," defined in terms of a contiguous group of states with high age-adjusted stroke mortality rates, was first identified in the mid-1960s. The states that define the stroke belt are Alabama, Arkansas, Georgia, Indiana, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia.", id., at 434; and

"Figure 2 displays a map of the 644 counties that define the diabetes belt. This belt includes portions of the states of Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia, as well as the entire state of Mississippi. The prevalence of diabetes in the diabetes belt was 11.7% (95% CI = 11.4%, 12.0%). The prevalence of diabetes in the rest of the country was 8.5% (95% CI = 8.3%, 8.6%).", id., at 436-437);

Fenelon A, Boudreaux M, Life and death in the American city: Men's life expectancy in 25 major American cities from 1990 to 2015, Demography 56(6):2349-2375 (2019) (examining differing improvements in life expectancy among U.S. cities; identifying high performing cities; and comparing their performance compared to life expectancy nationwide, as follows:

"We examine changes in men's life expectancy at birth for the 25 largest U.S. cities from 1990 to 2015, using mortality data with city of residence identifiers. We reveal remarkable increases in life expectancy for several U.S. cities. Men's life expectancy increased by 13.7 years in San Francisco and Washington, DC, and by 11.8 years in New York between 1990 and 2015, during which overall U.S. life expectancy increased by just 4.8 years.", id., at 2349;

"Life Expectancy by City, 1988–2015

Men's life expectancy at birth by city in each five-year period is shown in Table 2. Cities are sorted by the number of years of life expectancy gained between the early period (1988–1992) and the late period (2011–2015). The largest gains occurred in San Francisco, Washington, DC, and New York City. San Francisco and Washington, DC, each gained 13.7 years between the early and late periods, whereas life expectancy rose by only 4.8 years for men nationwide. …. Other cities that exhibited gains in life expectancy substantially above the national average include Los Angeles, Chicago, and Boston. Each gained between 9 and 10 years of life expectancy between the early and late period.

The improvement in men's life expectancy in San Francisco, Washington, DC, and New York City is particularly remarkable given the 23-year time span. Gains in each city amounted to more than half a year per year during the period. As shown in Fig. 1, it took 71 years for U.S. men's life expectancy to increase by 13.7 years, the number of years gained since 1990 in San Francisco and Washington, DC (Xu et al. 2016).", id., at 2355-56;

"Three cities stand out in their improvement in life expectancy from 1990 to the present: men in New York City, Washington, DC, and San Francisco gained more than 11 years of life expectancy in less than 25 years. Men's life expectancy in these cities increased by more than one-half year per year during this period, with the most rapid gains occurring during the late 1990s. Between the five-year periods of 1993–1997 and 1998–2002, life expectancy increased by 5.3 years in San Francisco, 4.6 years in Washington, DC, and 4 years in New York City. It has taken 71 years for U.S. men's life expectancy to increase by the same number of years gained in Washington, DC, and San Francisco since 1990. Slightly behind these top performers are other successful cases: specifically, Los Angeles, Chicago, and Boston each gained 9–10 years of life expectancy during this period. These gains are particularly significant when placed in the context of U.S. men's life expectancy as a whole, which increased by fewer than 5 years from 1988–1992 to 2011–2015.", id., at 2367; and

"The widening urban/rural gap in health and mortality is also manifested in the growing regional divergence in mortality outcomes (Fenelon 2013); specifically, the southern states have fallen increasingly far behind the Northeast and West Coast (Population Reference Bureau 2018). The surging life expectancy of many large cities, particularly those on the East and West Coasts, are not isolated trends but are instead reflections of broader processes of geographic inequality that have unfolded over the past three to four decades.", id., at 2368);

Goodwin JS, Kuo YF, Brown D, Juurlink D, Raji M, Association of chronic opioid use with presidential voting patterns in US counties in 2016, JAMA Network Open 1(2):e180450 (2018)[41] (analyzing the geographically uneven use of opioids; calculating the association between a county's Republican presidential vote and opioid use within its jurisdiction; and finding:

"The correlation between a county's Republican presidential vote and the adjusted rate of Medicare Part D recipients receiving prescriptions for prolonged opioid use was 0.42 ($P < .001$). In the 693 counties with adjusted rates of opioid prescription significantly higher than the mean county rate, the mean (SE) Republican presidential vote was 59.96% (1.73%), vs 38.67% (1.15%) in the 638 counties with significantly lower rates.", p. 1;

"In examining the maps showing the geographic distribution of the opioid epidemic, several observers have noted the similarity to the results of the 2016 presidential election. [Cites omitted.] Counties and states with the highest opioid use were often areas carried by the Republican candidate in the election.", p. 2;

"Counties with the highest rates were predominately concentrated in the South and Appalachian areas, as well as Michigan and some western states. The second map shows the percentage of the presidential vote for the Republican candidate for each county, also ordered by quintile. The 2 maps share some similar patterns. The correlation coefficient between the 2 rates at the county level was 0.32 (P < .001).", p. 3;

"The presidential vote was one of the largest differences between counties with high and low rates of opioid use, with the former voting for the Republican candidate at a mean (SE) rate of 59.96% (1.73%) and the latter voting for the Republican candidate at a mean (SE) rate of 38.67% (1.15%).", p. 4; and

"Republican support explained 18% of the variance in county rates of opioid use in 3100 counties in the United States, with counties whose opioid prescription rates were above average having a higher mean (SE) Republican vote (59.96% [1.73%]) than counties with prescription rates below average (38.67% [1.15%]). ….

The findings of this study add to the emerging literature on the relationship between health status and support of Donald Trump in the 2016 election. …. Similarly, Bor reported that a 2016 Republican presidential vote at the county level was strongly and negatively correlated with change in life expectancy between 2008 and 2016", p. 8 (footnote omitted);

Haffajee RL, Lin LA, Bohnert AS, Goldstick JE, Characteristics of US counties with high opioid overdose mortality and low capacity to deliver medications for opioid use disorder, JAMA Network Open 2(6):e196373 (2019)[42] (similarly finding that "Opioid highrisk counties also had … a lower percentage democratic vote in the 2016 presidential election.");

Rolheiser LA, Cordes J, Subramanian SV, Opioid prescribing rates by Congressional Districts, United States, 2016, American Journal of Public Health 108(9):1214-1219 (2018) (similarly analyzing the geographically uneven rates at which opioids are prescribed, and identifying the Congressional districts where opioids are highly prescribed, and the districts where they are not:

"Results. High prescribing rate districts were concentrated in the South, Appalachia, and the rural West. Low-rate districts were concentrated in urban centers.", id., at 1214;

"Districts with the 10 highest rates were overwhelmingly contained in the Southeastern states, whereas districts with the 10 lowest rates were entirely contained in California, New York City, and Virginia (Table 1). Interestingly, the state of Virginia contained both a top and bottom 10 prescribing rate district. However, these extremes within the state may be expected, as the low-rate district contains Arlington County, which is near Washington, DC, whereas the high-rate district covers the far western part of the state along the border with West Virginia.", id., at 1215;

"… there was a concentration of high prescribing rates throughout the South and along Appalachia. These areas have been highlighted as the most at-risk regions in terms of opioid-related mortality.", id., at 1215 (footnote omitted);

"Major urban districts like San Francisco and Los Angeles, California; Chicago, Illinois; Atlanta, Georgia; New York City; and Boston, Massachusetts, displayed rates well below the average.", id., at 1216;

"An examination of actual state rates (not district rates averaged at the state level) using the previously defined high–high, high–low, low–high, and low–low categories once again highlighted the Southeastern hotspot. High–high districts contained district rates above the third quartile of 80.80 and state rates above the third quartile of 80.55 (Figure 2). These districts were predominately in the South, with the exception of Michigan and Indiana …. Low–low districts contained district rates below the first quartile of 49.4 and state rates below the first quartile of 58.65. The majority of low–low districts were contained in New York City and the Los Angeles area.", id., at 1216; and

"… at-risk districts were concentrated in the Southeastern states with clear rural versus urban variation." id., at 1218);

Brandenburg MD, Mark A, Prescription opioids are associated with population mortality in US Deep South middle-age Non-Hispanic Whites: An ecological time series study, Frontiers in Public Health 7:252 (2019)[43] (finding that:

"Between 1990 and 2016, the top 10 states with increasing probability of death between the ages of 20 and 55 years were all in the South. These states were: Alabama, Arkansas, Kentucky, Louisiana, Mississippi, New Mexico, Oklahoma, South Carolina, Tennessee, and West Virginia.");

Knopov A, Sherman RJ, Raifman JR, Larson E, Siegel MB, Household gun ownership and youth suicide rates at the State level, 2005–2015, American Journal of Preventive Medicine 56(3):335-342 (2019) (reporting suicide rates among teenagers, by state; the four with the highest suicide rate are Red States; the seven with the lowest rate are Blue States);

Bleyer A, Siegel SE, Thomas CR, Increasing firearm deaths in the youngest Americans: Ecologic correlation with firearm prevalence, medRxiv 19009191 (2019)[44] (finding:

"Prior to 2004, the childhood firearm death rate did not increase during the Federal Assault Weapons Ban. Since then, the steadily increasing rate of sales and concomitant availability of, and access to, firearms in the U.S. has been associated with a dramatic increase in fatal firearm accidents in young children."; and

"Multilple comparisons have found states with more restrictive firearm legislation to have lower pediatric, unintentional, suicide, and overall firearm-related fatality rates, and more slowly rising suicide rates.");

Goyal MK, Badolato GM, Patel SJ, Iqbal SF, Parikh K, McCarter R, State gun laws and pediatric firearm-related mortality, Pediatrics 144(2):e20183283 (2019)[45] (noting that "~7 US children die of firearm related injuries daily", and reporting the results of a study seeking to determine if there is an association between stricter firearm legislation at the state level and lower pediatric firearm-related mortality:

"RESULTS: A total of 21 241 children died of firearm-related injuries during the 5- year period. States with stricter gun laws had lower rates of firearm-related pediatric mortality (adjusted incident rate ratio 0.96 [0.93–0.99]). States with laws requiring universal background checks for firearm purchase in effect for ≥5 years had lower pediatric firearm-related mortality rates (adjusted incident rate ratio 0.65 [0.46–0.90]).

CONCLUSIONS: In this 5-year analysis, states with stricter gun laws and laws requiring universal background checks for firearm purchase had lower firearm related pediatric mortality rates.";

"In our study, which was specific to children, we found that states with laws requiring universal background checks for firearm purchases had lower firearm-related mortality. The presence of these laws was associated with a >35% lower rate of firearm-related mortality, even after adjustment for socioeconomic factors and gun ownership."); and concluding that

"Our findings reveal an important association between firearm legislation and pediatric firearm-related mortality.");

Fox AM, Himmelstein G, Khalid H, Howell EA, Funding for abstinence-only education and adolescent pregnancy prevention: Does state ideology affect outcomes?, American Journal of Public Health 109(3):497-504 (2019) (examining the relationship between abstinence-only education funding and adolescent birthrates over time, and finding:

"Results: Federal abstinence-only funding had no effect on adolescent birthrates overall but displayed a perverse effect, increasing adolescent birthrates in conservative states. Adolescent pregnancy–prevention and sexuality education funding eclipsed this effect, reducing adolescent birthrates in those states.";

"Specifically, we estimated that conservative states received $692 million in federal abstinence funding between 1998 and 2016 (Table A). In 2008 alone, conservative states received more than $71 million in abstinence funding, which amounts to $4.52 per pupil. With an average effect of raising births by 0.20 (0.30 + –0.06) per 1000, we estimate that the change in the birthrate from this single year of abstinence funding amounted to a change in the birthrate of 1.08 per 1000, or 1080 additional births, to adolescents than would have otherwise been the case."; and

"... we found conservative states to have experienced an increase in births following infusions of abstinence funding. Moreover, in these same states, adolescent pregnancy–prevention funding was associated with a decrease in adolescent births. Thus, ironically, the states that have most favored abstinence education and eschewed comprehensive sexuality education have seen the largest effects from these policies (with abstinence funding increasing births and comprehensive sexuality education funding decreasing births).

Support for comprehensive sexuality education is not inconsistent with the notion that adolescents should delay sexual debut until they are emotionally prepared, as other research has suggested. However, our results suggest that efforts to encourage abstinence in the absence of providing more comprehensive information can be detrimental, particularly in conservative states, where birthrates have historically been the highest.");

Cavazos-Rehg PA, Krauss MJ, Spitznagel EL, Iguchi M, Schootman M, Cottler L, Grucza RA, Bierut LJ, Associations between sexuality education in schools and adolescent birthrates: A state-level longitudinal model, Archives of Pediatrics & Adolescent Medicine 166(2):134-140 (2012) (examining the correlation between politically conservative States and high adolescent birthrates, and stating:

"States with higher religiosity rankings and greater political conservatism had higher adolescent birthrates.", id., at 134; and

"States with the highest conservative values paradoxically have the highest rate of adolescent births across these states ….", id., at 139);

Herian MN, Tay L, Hamm JA, Diener E, Social capital, ideology, and health in the United States, Social Science & Medicine 105:30-37 (2014) (reviewing prior analyses, and stating:

"Notably, the analyses demonstrate that the presence of a more liberal government is related to a higher rate of reported health, a lower rate of reported smoking, lower BMI, and fewer numbers of days with poor health. In short, it appears that the presence of a liberal government – more elected Democrats who favor socially directed policies -- is associated with improved health and reductions in health risks.", id., at 34; and

"At the same time, results provide further evidence that the existence of liberal governments help promote the health of citizens in a state ….", id., at 35.

The poor performance of the governmental officials in Red States is, of course, not confined to their inability to predict actions[46] that would have improved the infant mortality rates, the rates of disease, and the life spans of the Americans in their jurisdictions. Those officials are also responsible for poor predictions that have led to inferior economic outcomes for their States. Consequently, when EPA weighs the predictions in support of its proposal, I urge that EPA also consider:

McCarty N, Poole KT, Rosenthal H, Polarized America: The Dance of Ideology and Unequal Riches (MIT Press) (2nd edition) (2016) (observing that “high per capita income states are now blue (Democratic) and low per capita income states are red (Republican)”, p. 13); and

Gilligan J, Why Some Politicians Are More Dangerous Than Others (John Wiley & Sons) (2011) (quantifying the two major parties’ relative performance on a variety of issues for which data is available, and concluding:

“But what the data presented here show is that, with, regard to most issues, we do not need to speculate about the future, for we already know what the past has shown us - namely, that it is Republican policies that have repeatedly, regularly, and with remarkable consistency brought us large increases in the rate and duration of unemployment, in the frequency, depth, and duration of recessions and depressions, in socio-economic inequalities in wealth and income, and in rates of suicide, homicide, and (since the mid-1970s) imprisonment and capital punishment; and it is Democratic policies that have brought us equally large decreases in all of those destructive phenomena (even in imprisonment and capital punishment, as the contrast between the Red and Blue States shows).”, at 186).

Comparing Presidential administrations’ performance provides further confirmation of the parties’ differing abilities to predict and deploy actions that benefit the general public, and to predict and avoid actions that do not. Consequently, when determining what weight should be given to the predictions – whether offered by commenters or by EPA’s current managers -- that support this rulemaking, I urge that EPA also consider the results reported in the peer-reviewed literature below:

Dorling D, Commentary: All the Presidents’ children, International Journal of Epidemiology 43(3):827-829 (2014):

"All else taken into account, some 3% more infants die each year when a Republican president is the resident of the White House as compared with when a Democrat is incumbent. Democrat presidents may not be messiahs, but Republicans ones, it transpires, are worse.", id., at 827;

“Put another way, Rodriguez et al.’s paper finds that for babies conceived during the incumbency of a Republican president, some 3% fewer are likely to see their first birthday than are babies conceived during Democratic tenure.”, id.;

“It was reported that infant mortality rates in the USA were rising absolutely for the first time since at least the 1950s in 2005, during the Bush administration’s tenure. It was in 2010 that the first overall fall in life expectancy for all of the USA was reported. Those falls in US life expectancy had occurred 2 years earlier, at the end of the Bush era in 2008.”, id. (footnotes omitted); and

“It takes one Democrat period of office to reduce the level [of infant deaths] again, to reduce it below that which would be expected given all the usual trends and factors. But what would happen if there were Democrat mandate after Democrat mandate with no intervening Republican backsliding?”, id., at 828;

Rodriguez JM, Bound J, Geronimus AT, US infant mortality and the President's party, International Journal of Epidemiology 43(3):818-826 (2013):

"Background Infant mortality rates in the US exceed those in all other developed countries and in many less developed countries, suggesting political factors may contribute.

Methods Annual time series on overall, White and Black infant mortality rates in the US were analysed over the 1965–2010 time period to ascertain whether infant mortality rates varied across presidential administrations. ….

Results Across all nine presidential administrations, infant mortality rates were below trend when the President was a Democrat and above trend when the President was a Republican. This was true for overall, neonatal and post-neonatal mortality. Regression estimates show that, relative to trend, Republican administrations were characterized by infant mortality rates that were, on average, 3% higher than Democratic administrations. In proportional terms, effect size is similar for US Whites and Blacks. US Black rates are more than twice as high as White, implying substantially larger absolute effects for Blacks.

Conclusions We found a robust, quantitatively important association between net of trend US infant mortality rates and the party affiliation of the president.", id., at 818;

"Researchers have reported within-country associations between the political party at the helm and temporal patterns of suicide rates, finding suicide rates are higher under more conservative regimes.", id., at 819 [footnotes omitted.];

"relative to trend, infant mortality rates are, on average, 3% higher during Republican administrations.", id., at 822;

"We have described a quantitatively important, robust association between net-of-trend US infant mortality rates and the party affiliation of the president. Relative to trend, national and race-specific infant, neonatal and post-neonatal mortality rates decrease under Democratic administrations and increase under Republican administrations.", id., at 822;

"Infant mortality rates are about 3% higher during a typical Republican-president year compared with a typical Democratic-president year.", id., at 824; and

"The current paper adds to the extant record on infant mortality and disparities in infant mortality rates by demonstrating a powerful, robust association between variations in US infant mortality rates over the past half-century and the inclusion of a political variable: the political party of the president.", id., at 825;

Rodriguez JM, The politics hypothesis and racial disparities in infants' health in the United States, SSM-Population Health 8:100440 (2019)[47] (examining the relationship between the political party of the President and a variety of health indicators for infants: overall infant mortality rates (IMR); whites' infant mortality rates (WIMR), black infant mortality rates (BIMR); low birthweight (LBW); and preterm birth (PB) rates; finding a "drastic difference" between the two parties, in which Republican administrations have underperformed Democratic administrations; and reporting:

“3. Results

Table 1 shows a drastic difference between the political party of presidents across de-trended IMR-relevant social determinants of health indicators. There is a general underperformance of Republican (vs. Democratic) presidents at improving the social determinants of health. All medians and means of de-trended overall infant mortality rates (IMR), whites' (WIMR), blacks’ (BIMR), low birthweight (LBW) and preterm birth (PB) rates are negative — i.e., decrease relative to trend — under Democratic presidents and are positive — i.e., increase relative to trend — under Republican presidents.

…. For instance, [ordinary least squares, “OLS”] linear regression estimates show that, net of trend, the average socially-conservative Republican president (average DWN=0.70) is associated with .29 (IMR), .25 (WMR), and .50 (BIM) more annual infant deaths per 1,000 live births compared to the average socially-liberal Democratic president (average DWN=–.56).”;

“The president's party is the most important predictor of IMR and WIMR, and the third most important of BIMR (after LBW and rurality). [Least angle regression, “LAR”] best-fitting standardized models show that, net of trend, IMR, WIMR and BIMR are on average .17, .15, and .25 respectively higher in a typical Republican president-year compared to a typical Democrat-president year (Tables S2a–S2c, Appendix). With 28 Republican-president years between 1965 and 2010, Republican presidents are associated with a total slowdown of the IMR, WIMR and BIMR equivalent to 4.76, 4.20, and 7.0 infant deaths per 1,000 births respectively.

[Seemingly Unrelated Regressions, “SUR”] analyses corroborate Republican administrations underperform Democratic ones in IMR, WIMR, and BIMR. Effects on BIMR are also noticeably larger than on WIMR under Republican administrations, thus promoting racial disparities in health. Estimates from Model 6 show that, net of trend, Democratic presidents would have saved 1 extra infant life per 1,000 live births for every 5–6 years of Republican administrations — i.e., approximately 20,000 infant lives in the study period. Had Republican presidents had the record of Democratic presidents for IMR, most (if not all) IMR differences between the U.S. and the rest of the developed world would possibly have never existed.”;

“A similar scenario arises for WIMR and BIMR, which were, net of trend, .17 and .29 units higher respectively, during a typical Republican-president-year vs. a typical Democratic-president-year. The racial gap in IMR therefore increased by about 1 infant death per 1,000 live births for every 8 years of Republican administration. Net of trend, observed total increase in the black-white IMR gap between 1965 and 2010 was 7.6 units, of which 3.5 (46%) could be attributed to the 28 years of Republican administrations. Republican presidents may have been the single most important factor affecting national IMRs and racial disparities in infant mortality in the U.S. during the last half century.”; and

"Net of trend, the economic, social and racial conservatism incorporated by the Republican Party since the political Realignment has worsened overall and race specific IMRs and increased racial disparities in IMRs.");

Lee BX, Wexler BE, Gilligan J, Political correlates of violent death rates in the US, 1900–2010: Longitudinal and cross-sectional analyses, Aggression and Violent Behavior 19(6):721-728 (2014):

"Results: The party of the president was significantly associated with annual changes in suicide and homicide rates, unemployment rates, and GDP ($p < 0.001$ to $p < 0.05$, depending on the measure and time lag), with higher violent death and unemployment increases being associated with Republican presidencies and higher GDP with Democratic ones. …. Suicide and homicide rates were higher in states that voted for the Republican candidate for presidency than in states that voted for the Democratic candidate ($p < 0.0001$ and $p < 0.07$). Conclusions: Violent deaths were associated with an increase under Republican presidents and a decrease under Democratic presidents, [and] were higher in states that vote for the Republican than for the Democratic presidential candidates ....", id., at 721;

"Suicide, homicide, and combined suicide/homicide rates from 1900 to 2010 were found to be associated with an increase under Republican presidents and a decrease under Democratic ones with statistical significance …. …. In other words, the two parties were almost mirror images of each other, with the suicide and homicide rates showing an increase during Republican presidencies to the same degree as they showed a decrease during Democratic presidencies …. The cumulative differences in unemployment were also near mirror images of each other, in the same direction as the violent death rates. Cross-sectional analyses were consistent with the national longitudinal data linking political party and violent death rates. Suicide and homicide rates were significantly higher in Republican dominated states than in Democrat-dominated ones as determined by the presidential voting patterns in the years 2000, 2004, and 2008 ….", id., at 725;

"No previous study had yet integrated these variables – economic measures, the political party in power (conservative or liberal), and rates of lethal violence (both suicide and homicide) -- in an overarching empirical synthesis over time and across space. This article endeavored to accomplish this by comparing the track records of the two major U.S. political parties over more than one hundred years in terms of changes in national suicide and homicide rates and to link them to core policy orientations. The hypothesis was that the approaches of the two major parties of the U.S. government lead to different violent death rates and that this difference would be detectable statistically. The results answered in the affirmative.", id., at 726; and

"5. Conclusion

Suicide and homicide are major public health problems. Rates of both were associated with an increase under Republican presidents and a decrease under Democratic presidents, and increase alongside increasing unemployment and falling national GDP.", id., at 728; and

Potrafke N, Government ideology and economic policy-making in the United States - a survey, Public Choice 174(1-2):145-207 (2018) (concurring with the often-found conclusion that "Parties do matter at the state level.", id., at 201; but also focusing analysis on the comparative performance of Republican versus Democratic presidential administrations; and finding:

"Many studies conclude that parties do matter in the United States. Democratic presidents generate, for example, higher rates of economic growth than Republican presidents ….", id., at 145;

"Economic outcomes have differed under Democratic and Republican US presidents (and unified governments such as a Democratic president and Democratic-dominated Congress) since the end of the Second World War. Various early studies have shown that Gross National Product (GNP), Gross Domestic Product (GDP) or real GNP/GDP or personal income growth were higher under Democratic than Republican presidents, especially during the first two years of a presidential term (Hibbs 1987; Alesina and Sachs 1988; Haynes and Stone 1990; Alesina and Rosenthal 1995; Alesina et al. 1997; Blomberg and Hess 2003; Verstyuk 2004; Krause 2005; Grier 2008; Bartels 2016; Pastor and Veronesi 2017). In a similar vein, the unemployment rate was lower under Democratic than Republican presidents (Hibbs 1986, 1987; Alesina and Sachs 1988; Haynes and Stone 1990; Belke 1996; Alesina et al. 1997; Blomberg and Hess 2003; Verstyuk 2004). …. A fascinating descriptive study showing that economic performance was better under Democratic than Republican presidents is Blinder and Watson (2016). The authors focus on the gap in GDP growth under Democratic and Republican presidents: over the 1949–2012 period, annual GDP growth was on average 1.79 percentage points higher under Democratic than Republican presidents. [Footnote omitted.] Other measures of real outcome variables giving rise to the same conclusion are nonfarm business output and industrial production and employment, and corporate profits. Stock market returns were higher under Democratic than Republican presidents (Santa-Clara and Valkanov 2003; Pastor and Veronesi 2017).

Income inequality also escalated under Republican governments: 'on average, the real incomes of middle-class families have grown twice as fast under Democrats as they have under Republicans, while the real incomes of working poor families have grown ten times as fast under Democrats as they have under Republicans' (Bartels 2016, p. 4). The incomes of black Americans increased faster under Democratic than Republican presidents (Hajnal and Horowitz 2014). The share of the top 1% of the income distribution grew to a larger extent under Republican than Democratic presidents (Schinke 2014).", id., at 147; and

"Democratic and Republican governments had different policies at the national and state levels of government in the United States. Economic performance as measured, for example, by annual GDP growth was better under Democratic than Republican US presidents since the 1950s, a difference that was also true under divided government (when the president's party did not also control a majority in Congress).", id., at 200-201.)

Let's recall that EPA is proposing to substantially revise the regulations that govern two of the largest sources of wastewater from steam electric power generating facilities,[48] an industry category that, along with its benefits, is the cause of massive harm to public health and the environment.[49] Evidently, at the time of the proposal's publication, the proponents believed that the proposal, if adopted, would be beneficial, based upon their predictions of its future effects. However, EPA's confidence in their predictions must be reevaluated as part of this proceeding; that's the purpose of the legally required notice-and comment process. When conducting that reevaluation, I urge that EPA – and particularly the proposal's proponents – remain mindful that: the proposal's alleged merits are predictions; that its proponents include many whose record of predicting the consequences of governmental action is miserable; and that the cost to the public from their erroneous predictions has been enormous. EPA should absolutely not judge the proposal's merits by its consistency with its proponents' theories or with Republican Party orthodoxy. As EPA determines whether to proceed with or withdraw this proposal, the results obtained in the laboratory of real life – including the harm to Americans due to the misguided governmental decisions reported in the literature cited above – will provide much better evidence than the proponents' hypotheses.

EPA may, of course, disagree with much of the above, finding instead that the conclusions reached by the researchers above are simply untrue, or that those conclusions in no way reduce EPA's confidence in the skill of the predictors advocating for this proposal, or that the harm to Americans described above is otherwise inconsequential. If so, I urge that EPA state its findings in this rulemaking.

2 For example, by my rough count: EPA's Benefit and Cost Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. EPA-821-R-19-011, uses the word "assume" or related words over 140 times, and uses the word "predicted" or related words over twenty times; EPA's Supplemental Environmental Assessment for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. EPA-821-R-19-010, uses the word "assume" or related words over sixty times; and EPA's Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. EPA-821-R-19-009, uses the word "assume" or related words over thirty times.
3 Available at https://www.cadc.uscourts.gov/internet/opinions.nsf/a86b20d79beb893e85258152005ca1b2/$file/17-1145-1682465.pdf
4 Available at
https://www.cadc.uscourts.gov/internet/opinions.nsf/D635BFF007DFAA56852582EC00509B00/$file/17- 1155-1746106.pdf
5 Available at https://elr.info/litigation/48/20147/south-carolina-coastal-conservation-league-v-pruitt
6 Available at https://elr.info/litigation/49/20197/puget-soundkeeper-alliance-v-wheeler
7 Available at http://cdn.ca9.uscourts.gov/datastore/opinions/2018/08/09/17-71636.pdf
8 Available at https://www.leagle.com/decision/infdco20180411e19
9 Available at https://elr.info/litigation/48/20046/pineros-y-campesinos-unidos-del-noroeste-v-pruitt
10 Available at https://ecf.dcd.uscourts.gov/cgi-bin/show_public_doc?2016cv1074-42
11 Available at https://www.leagle.com/decision/infdco20180626742
12 Available at https://casetext.com/case/in-re-ozone-designation-litig-1
13 Available at https://ecf.dcd.uscourts.gov/cgi-bin/show_public_doc?2017cv0652-25
14 Available at
https://www.cadc.uscourts.gov/internet/opinions.nsf/0/B42E4D7405452F66852582C200525ACE/$file/
15- 1487.pdf 15 Available at https://www.leagle.com/decision/infdco20180725928
16 Available at http://cdn.ca9.uscourts.gov/datastore/opinions/2017/12/27/16-72816.pdf
17 Available at https://www.gpo.gov/fdsys/pkg/USCOURTS-ctd-3_17-cv-00796/pdf/USCOURTS-ctd-3_17- cv-00796-0.pdf
18 Available at
http://www2.mdd.uscourts.gov/Opinions/Opinions/Pruitt%20Memo%20and%20order%20re%20MSJ%20FOR%20WEBSITE.pdf

19 Available at https://elr.info/litigation/48/20027/sierra-club-v-pruitt
20 Available at https://law.justia.com/cases/federal/districtcourts/oregon/ordce/3:2012cv01751/109177/190/
21 Available at https://elr.info/litigation/49/20008/sierra-club-v-united-states-environmental-protectionagency
22 EPA may disagree with my opinion regarding the quality of its decision making. After considering the Courts' opinions cited above, if EPA concludes that its performance since January 2017 has been satisfactory, and EPA intends to maintain that level of performance in the future, I urge that EPA make those findings in its response to comments in this rulemaking.
23 See, report of The Center for Public Integrity available at: https://www.publicintegrity.org/2017/11/09/21274/most-46-political-appointees-working-epa-previouslyworked-climate-change-doubters
24 Available at https://www.nature.com/articles/d41586-018-05706-9 . Noting that the journal's representatives conducted dozens of interviews with current and former staffers, Tollefson writes: "What most troubles many EPA scientists is the Trump administration's systematic and unprecedented effort to undermine the way in which science is used by the agency. Scientists there say they and their work have been largely ignored by senior EPA leadership."; and, offers an observation that seems particularly germane to this rulemaking: "By bypassing EPA scientists and ignoring their findings, [Administrator Pruitt's] team ran the risk of weakening the EPA's defence in the many lawsuits that states and environmental groups were filing against the agency."
25 See Daubert v. Merrell Dow Pharmaceuticals, Inc., 509 U.S. 579, 593 (1993), and citing cases.
26 I also urge that EPA accept that, although the decisions held to be erroneous in the above cases were vacated, the costs borne by the public due to those decisions (including the time and money consumed by the Federal courts to adjudicate the suits, and by EPA in their fruitless defense) are gone forever. Whether the harm to EPA's reputation from its recent record of unlawful actions, and the harm to the reputation of the senior managers in the Agency responsible for those actions, is reversible is unclear.
27 Hopefully, my contention is not in dispute, at least with respect to the issues being addressed in the subject rulemaking. If additional information is needed, please see empirical analyses at Karol D, Red, Green, and Blue: The Partisan Divide on Environmental Issues (Cambridge University Press) (2019)
28 Accordingly, such parties have a track record for making predictions that, at least theoretically, could be analyzed to determine if that party is a good predictor, or not.
29 See, e.g.: The U.S. Chamber of Commerce's scores, at https://www.uschamber.com/how-theyvoted/2018#all ;The American Conservative Union's ratings of Federal and State legislators, at http://acuratings.conservative.org/ ; Americans for Prosperity's Scorecard, at https://afpscorecard.org/ ; FreedomWorks's Scorecard, at http://congress.freedomworks.org/ ; Heritage Action's Scorecard, at https://heritageaction.com/scorecard ; National Taxpayers Union's congressional ratings scorecard, at https://www.ntu.org/ratecongress/ ; as well as the League of Conservation Voters' Scorecard, at http://scorecard.lcv.org/; and the various State legislative scorecards identified at the Ballotpedia website, at https://ballotpedia.org/State_legislative_scorecards .
30 Likewise, we should expect the opposite in a Democratic-controlled State.
31 Common sense is probably enough to show that knowing a forecaster's past performance helps a decision maker decide how much weight to give that forecast. If more is needed, please see: Colson AR, Cooke RM, Expert elicitation: Using the classical model to validate experts' judgments, Review of Environmental Economics and Policy 12(1):113-132 (2018) (describing the "classical model" for aggregating experts' judgments, in which the weight given each expert's prediction is determined by that expert's past performance; "This recent work on the classical model's out-of sample performance further demonstrates the validity of performance-based weighting of experts.", p. 129; "Thus, for decisions or policies with a large potential impact on society, we would argue that the classical model and its validated assessments are the best tool for incorporating expert judgments when they are needed.", p. 132); Hanea AM, Burgman M, Hemming V, IDEA for Uncertainty Quantification, in Dias LC, et al., Elicitation: The Science and Art of Structuring Judgement (2018), pp. 95-117 ("These signals illustrate one of the most important lessons of empirical studies over the last decade: an expert's performance on technical questions may be predicted to some extent by the history of their performance on similar questions previously." p. 109); and Mellers B, Tetlock P, Arkes HR, Forecasting tournaments, epistemic humility and attitude depolarization, Cognition 118:19-26 (2019) ("Without measurement of forecasting accuracy, learning can't take place." p. 3; "We agree that attitude polarization makes politics dysfunctional, creating gridlock, but it does not follow that each side in a polarized debate is equally wrong.").
32 For the purpose of my comment, a "Red State" is a State with a Cook Partisan Voting Index ("PVI") of "R+1" or higher, and a "Blue State" is a State with a PVI of "D+1" or higher. See, https://en.wikipedia.org/wiki/Cook_Partisan_Voting_Index . Accordingly, among the States whose performance is addressed in the literature that I am asking EPA to consider: Oklahoma, West Virginia, Arkansas, Kentucky,

Alabama, South Dakota, Tennessee, Kansas, Louisiana, Alaska, Indiana, Mississippi, Missouri, South Carolina, Texas, and Iowa are each considered to be a Red State; and Hawaii, Vermont, Massachusetts, California, New York, Washington, New Jersey, Connecticut, Oregon, Minnesota, Colorado, and Michigan are each a Blue State.
33 Available at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4109895/ .
34 Available at https://www.demographic-research.org/volumes/vol39/33/39-33.pdf .
35 Available at https://jamanetwork.com/journals/jama/fullarticle/2678018 .
36 Available at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC6771562/pdf/PADR-45-549.pdf
37 Note that a rise in a State's relative rank order for CVD DALYs is an undesirable change.
38 Available at https://www.ahajournals.org/doi/pdf/10.1161/JAHA.112.005371 .
39 Available at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5807217/pdf/nihms926530.pdf .
40 Available at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4537395/pdf/nihms713807.pdf .
41 Available at https://jamanetwork.com/journals/jamanetworkopen/fullarticle/2685627
42 Available at https://jamanetwork.com/journals/jamanetworkopen/fullarticle/2736933
43 Available at https://www.frontiersin.org/articles/10.3389/fpubh.2019.00252/full
44 Available at https://www.medrxiv.org/content/medrxiv/early/2019/10/18/19009191.full.pdf
45 Available at https://pediatrics.aappublications.org/content/pediatrics/144/2/e20183283.full.pdf
46 Actions that were correctly predicted by governmental officials in Blue States, as the above literature shows.
47 Available at https://www.sciencedirect.com/science/article/pii/S2352827319300916
48 See, 84 FR, at 64622
49 See, generally: EPA's Benefit and Cost Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. EPA-821-R-19-011; EPA's Supplemental Environmental Assessment for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. EPA-821-R-19-010; the literature cited therein; and Burney JA, The downstream air pollution impacts of the transition from coal to natural gas in the United States, *Nature Sustainability* 6:1-9 (2020) (finding that, between 2005 and 2016, "the shutdown of coal-fired units saved an estimated 26,610 (5%–95% confidence intervals (CI), 2,725–49,680) lives and 570 million (249–878 million) bushels of corn, soybeans and wheat in their immediate vicinities; these estimates increase when pollution transport-related spillovers are included.").

Commenter Name: Patti Hershey
Commenter Affiliation: Lower Colorado River Authority (LCRA)
Document Control Number: EPA-HQ-OW-2009-0819-8317-A1
Comment Excerpt Number: 1

Comment Excerpt:

I. The Proposed Rule is Consistent with EPA Clean Water Act Authority and Appropriately Excludes Regulation of Wastewaters That Do Not Directly or Indirectly Discharge to Waters of the U.S.

The Clean Water Act (CWA) provides EPA with the authority to regulate facilities that are discharging effluent into Waters of the U.S. (WOTUS). As such, the Proposed Rule would apply to FGD wastewater and BA transport water only when the FGD and/or BA transport water is discharged either "directly" to surface water or "indirectly" to a POTW. LCRA agrees that EPA's ELG authority is limited to wastewater that discharges directly to surface water or indirectly to POTWs.

EPA recognized in its 2015 final ELG rule that ELGs do not apply to wastewaters that are reused in plant processes rather than discharged to a WOTUS or to a POTW:

The final rule does not establish an anti-circumvention provision that would have required internal monitoring to demonstrate compliance with certain numeric limitations and standards. Some public commenters argued that the proposed provision was unduly restrictive, and they stated that EPA already has authority to accomplish the goal of this particular provision, which is to ensure that wastestreams are being treated rather than simply diluted. EPA agrees with these commenters and thus decided that existing rules, along with the guidance in Section XVI.A.4 of this preamble and TDD Section 14, provide appropriate flexibility to steam electric power plants to combine wastestreams with similar pollutants and treatability, while adequately addressing EPA's concern that plants meet the effluent limitations and standards in this rule through treatment and control strategies, rather than through dilution. Furthermore, some commenters raised concerns that the proposed provision would be a disincentive for plants to internally re-use the treated wastewater within the plant, particularly when the reuse eliminates the discharge of the wastewater. For example, they stated that some steam electric power plants might opt to use a wet scrubber's FGD wastewater as reagent make-up for a new dry scrubber in an integrated design which would essentially evaporate the wet FGD wastewater. EPA notes that plants that internally reuse wastestreams for which EPA is establishing numeric limitations and standards (e.g., FGD wastewater) in a way that completely prevents discharge of that wastestream would not be subject to the numeric limitations and standards because they do not discharge the wastewater. EPA is aware of at least one plant that elected to take such an approach as an alternative to meeting NPDES permit limitations by installing wastewater treatment technology. See DCN SE06338. In general, EPA supports such approaches because they result in further progress towards achieving the pollutant discharge elimination goal of the CWA. Moreover, such approaches are favored because they reduce overall water intake needs.

80 Fed.Reg. 67838, 67862 (Nov. 3, 2015).

LCRA concurs with EPA's 2015 decision to not require monitoring at internal points, and to exempt from the ELGs wastestreams that will not be discharged either directly to WOTUS or indirectly to POTWs. LCRA agrees that power plants should be encouraged to recycle and/or reuse ELG wastestreams, including FGD wastewater and BA transport water in plant processes, and not discharge them. LCRA supports the Proposed Rule on this issue as the Proposed Rule is consistent with and does not change EPA's 2015 determination.

Commenter Name: Angie Rosser
Commenter Affiliation: West Virginia Rivers Coalition (WV Rivers), et al.
Document Control Number: EPA-HQ-OW-2009-0819-8321-A1
Comment Excerpt Number: 3

Comment Excerpt:

Additionally, WV Rivers is opposed to the lack of opportunity for the public to participate in this rule changing process. One online “public hearing” is not adequate to satisfy the requirement of public participation. Many rural residents in WV do not have access to internet in their homes and the nearest library may be an hour away, and therefor were excluded from the public process. We request public hearings to occur within the communities impacted by EPA's proposal.

Furthermore, the public comment period is inadequate. The comment period fell over a holiday when many people take several weeks off to travel and spend time with family. WV Rivers requests a 30-day extension to the comment period to account for the comment period falling during the busiest holiday season of the year.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 8

Comment Excerpt:

In the proposed rule, USEPA explains the authority it has as follows:

"The CWA also authorizes the EPA to promulgate nationally applicable pretreatment standards that control pollutant discharges from sources that discharge wastewater indirectly to waters of the U.S., through sewers flowing to POTWs, as outlined in section 307(b) and (c) of the CWA, 33 U.S.C. 1317(b) and (c). The EPA establishes national pretreatment standards for those pollutants in wastewater from indirect dischargers that pass through, interfere with, or are otherwise incompatible with POTW operations." 84 Fed. Reg. 64,623.

In these first two sentences USEPA is quoting or paraphrasing its role directly from the CWA; however, USEPA then goes on to say in the next sentence: "Pretreatment standards are designed to ensure that wastewaters from direct and indirect industrial dischargers are subject to similar levels of treatment. See CWA 301(b), 33 U.S.C. 131 l(b)." Id. This statement is not found in the provision cited and it's not at all clear to CWLP how USEPA draws that conclusion from the language in the provision cited.

As USEPA also explains in its description of the legal authority for pretreatment requirements: "In addition, POTWs are required to implement local treatment limitations applicable to their industrial indirect dischargers to satisfy any local requirements. See 40 C.F .R. 403.5" 84 Fed. Reg. 64,623. A review of the standard cited in 40 C.F.R. §403.5 will reveal this provision lays out the same standard articulated as the CWA, to prevent pass-through and interference at an individual POTW. CWLP can find no reference in the CWA or accompanying regulations that the goal of the PSES is to provide "similar levels of treatment" by PSES as BAT. "Pass through and interference" are quite different standards than the goal of elimination of discharges applicable to direct dischargers under the CWA. However, USEPA goes on to reiterate its conclusion that "[c]ategorical pretreatment standards are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BPT and BAT." 84 Fed. Reg.

64,624. Again, USEPA provides no citation for this link and or regulatory basis for the lack of independent consideration of technologies for pretreatment technologies.

Notably, USEPA has a regulatory definition for the terms "pass through" and "interference"[2] as used in the CW A and these regulatory definitions are not cited in the proposed rule and its explanation of legal authority to establish the PSES. See 40 C.F.R. §§403.3 (k) and (p). USEPA's definition of pass-through in 40 C.F.R. §403.3(p) states that "[t]he term Pass Through means a Discharge which exits the POTW into waters of the United States in quantities or concentrations which alone, or in conjunction with a discharge or discharges from other sources, is a cause of a violation of any requirement of the POTW's NPDES permit (including an increase in the magnitude or duration of the violation)."

Instead of referencing these definitions in explaining its interpretation of the PSES requirements of the CWA and in order to bolster the tenuous link it presents, USEPA turns to legislative history for support and states "Legislative history indicates that Congress intended for the combination of pretreatment and treatment by the POTW to achieve the level of treatment that would be required if the industrial source were discharging to a water of the U.S. (citation omitted)." While USEPA does not quote the precise reference from the legislative history, the need to rely on it reveals the questionable foundation for its position. CWLP believes that interpretation taken by USEPA in this proposal, even if long held, is inconsistent with the plain language of the statute and contrary to USEPA's own regulatory definitions. But even taking this justification as fact, CWLP believes that the intent of Congress in 1977 is clearly met by the factors at play at its facility and it's POTW. These factors include that CWLP is unable to precisely detennine the removal efficiency of the receiving POTW because the levels of pollutants (in this case selenium) leaving the POTW are very often too low to detect and the ELG limits for all parameters of the FGD ELG would be met by the POTW s discharge to the Sangamon River if they were applicable.[3]

[2] 40 C.F.R. 403.3(k) "The term Interference means a Discharge which, alone or in conjunction with a discharge or discharges from other sources, both: (1) Inhibits or disrupts the POTW, its treatment processes or operations, or its sludge processes, use or disposal; and (2) Therefore is a cause of a violation of any requirement of the POTW's NP DES permit (including an increase in the magnitude or duration of a violation) or of the prevention of sewage sludge use or disposal in compliance with the following statutory provisions and regulations or permits issued thereunder (or more stringent State or local regulations): Section 405 of the Clean Water Act, the Solid Waste Disposal Act (SWDA) (including title II, more commonly referred to as the Resource Conservation and Recovery Act (RCRA), and including State regulations contained in any State sludge management plan prepared pursuant to subtitle D of the SWDA), the Clean Air Act, the Toxic Substances Control Act, and the Marine Protection, Research and Sanctuaries Act."

[3] Section 301(n) of the CWA also gives USEPA the authority to vary the timelines in 301(b) or the requirements in 307(b) if a facility can demonstrate fundamentally different factors. CWLP believes that the factors applicable to its facility are fundamentally different than other facilities and fundamentally different to the factors considered by USEPA in this rulemaking.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 21

Comment Excerpt:

Pass Through and Interference

In USEPA's "Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Stearn Electric Power Generating Point Source Category," EPA-821-R-19-009 (November 2019) the drafters stated:

"As part of establishing pretreatment standards for existing sources (PSES) for a pollutant, the EPA examines whether the pollutant 'passes through' a POTW to waters of the U.S. or interferes with the POTW operation or sludge disposal practices. In determining whether a pollutant passes through POTW s for these purposes, the EPA compared the percentage of a pollutant removed by well-operated POTW s performing secondary treatment to the percentage removed by the BAT technology basis. A pollutant is determined to pass through POTWs when the median percentage removed by well-operated POTWs is less than the median percentage removed by the BAT technology basis. Pretreatment standards are established for those pollutants regulated under BAT that pass through POTWs." p. 8-7.

CWLP has already discussed its disagreement with this interpretation of the statutory obligation placed on the Agency by the plain language of the CWA and regulation. This elaboration in the Technical Support Document further illustrates this disagreement. It seems an arbitrary and capricious interpretation of the term "pass through" in the CWA to conclude as USEPA does here that any percent removal at a POTW performing secondary treatment of any amount no matter how tiny less than the percentage removal assumed for the 'Best Available Technology Economically Achievable' is passing through a POTW. This interpretation seems to be at odds with the common sense meaning of the terminology pass through and interference and when applied in this context CWLP finds this interpretation arbitrary and unreasonable.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 134

Comment Excerpt:

XXV. Legacy Wastewater and Combustion Residual Leachate are Properly Excluded from This Rulemaking. Until EPA Completes a Rulemaking to Address Those Waste Streams, the 1982 ELGs Apply.

A. New ELGs Properly Apply Only to Wastewater Generated After their Applicability Date.

As it did in the 2015 rule, EPA proposes to apply the ELGs for BATW and FGD wastewater to wastewater generated after the date on which the new ELGs become applicable. UWAG supports this approach, which is entirely consistent with the CWA's language, structure, and policy.

The statute explicitly requires EPA to consider a number of specific factors when selecting BAT technologies for a given industrial category or class of point sources, including the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, and the cost of achieving such effluent reduction. CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B). It also expressly authorizes EPA to consider "such other factors as the Administrator deems appropriate." Id.

Each of these factors counsels in favor of dealing separately with "legacy" wastewaters generated before the applicability date of new ELGs. By definition, such wastewater has been managed consistent with prior ELGs, which may authorize or even (in the case of low volume wastes) encourage commingling for treatment. The treatment technologies on which EPA based prior ELGs (such as surface impoundments, which are highly effective at removing suspended solids but which typically require large areas and long retention times to achieve optimal results) made it functionally impossible to discharge within a short amount of time after wastewater generation. Thus, the "age of equipment and facilities involved," the "process employed," and the "engineering aspects" of control measures all must be taken into consideration when deciding whether some additional treatment is required.

Consideration of the ELGs under which the wastewater was held and treated also is an important factor that the CWA authorizes EPA to consider, pursuant to its authority under "other factors that the Administrator deems appropriate." The CWA's technology-based provisions were designed to provide clear, consistent, nationally applicable effluent limitations for wastewater discharges from a given category or class of industrial sources based on the technology EPA determined was the "best available" for wastewater produced by those sources.[265] Although the limits apply to effluent discharges, the language and structure of the technology-based provisions make it clear that EPA must consider the attributes of the industrial source of those discharges. In this case, the source of the discharges comprises one or more treatment systems that were built and managed in order to achieve the 1982 ELGs. In determining whether and how to further regulate wastewater from those sources, assuming further regulation is lawful,[266] it will be entirely appropriate—indeed, essential—to consider the extent of reduction already achieved, the age of the equipment employed, process issues, engineering aspects, and, of course, cost.

[265] See, e.g., Senate Report 92-414, to Accompany S. 2770, at 8 (Oct. 28, 1971), *reprinted in* Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: October 18, 1972 (1972) ("In order to carry out the objective of this legislation, a two-phase program for applying effluent limits is created … the second based on best available technology…. In Phase II … communities and industries will be required to apply, . . . the best available technology."); Remarks of the Hon. John D. Dingell on Administration Efforts to Amend S. 2770 in Conference, at E 4883 (May 9, 1972), reprinted in Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: October 18, 1972 (1972) ("My colleague, HENRY S. REUSS, and I, joined by more than 40 other Members of the House, a few weeks ago sought to have the House adopt the 20th century concept of the Senate bill (S. 2770)" to address pollution through the use of best available technology); Submission of the Conference Report (S. Rept. 92-1236) on S. 2770 to the Senate - Senate Consideration of, and Agreement to the Conference Report, at S. 16873-4 (Oct. 4, 1972), reprinted in

Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: Oct. 18, 1972 (1972) ("In determining the 'best available technology' for a particular category or class of point sources, the Administrator is directed to consider the cost of achieving effluent reduction. The Conferees intend that the factors described in section 304(b) be considered only within classes or categories of point sources and that such factors not be considered at the time of the application of an effluent limitation to an individual point source within such a category or class."); Hearings before the House Public Works Committee, on H.R. 11895 and H.R. 11896, at 290 (Dec. 7-10, 1971), reprinted in Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: Oct. 18, 1972 (1972) ("S. 2770 eliminates over a period of time the concept of water quality standards and instead depends completely on effluent limitations based on the best available technology or better.

[266] It is far from clear that EPA possesses authority to retroactively apply new ELGs to wastewater generated and managed pursuant to prior ELGs. Such an approach undermines the clarity and advance notice the CWA's technology-based provisions were intended to provide to dischargers. As EPA and various courts have recognized, Congress understood that technology-based limits might, in some cases, force existing dischargers to cease operating rather than bear the substantial costs of retrofitting the necessary technologies. See Conference Report and Debates at 231 (Oct. 4, 1972), reprinted in Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: Oct. 18, 1972 (1972) ("If the owner or operator of a given point source determines that he would rather go out of business than meet the 1977 requirements, the managers clearly expect that any discharge issued in the interim would reflect the fact that all discharges not in compliance with such 'best practicable control technology currently available' would cease by June 30, 1977."); H.R. 11896 Together with Debate and Report at 450, reprinted in Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: Oct. 18, 1972 (1972) ("We all know that the economy is in terrible condition. We know that there is a high rate of unemployment and that there are many depressed areas throughout the Nation. It is precisely these areas which contain the most small businesses whose existence would be jeopardized by inability to pay the cost of controlling their pollution, and it is to these industries that this section is directed. No one in Congress wishes to legislate so irresponsibly that we drive out of business those who sincerely wish to abide by the new pollution laws but who, because of a bad state of the economy, will be forced to close."); Hearings before the Subcommittee on Environmental Pollution of the Committee on Environment and Public Works, U.S. Senate, Ninety-Fifth Congress, First Sess., at 505-506 (June 28-30 and July 1, 1977), reprinted in Covington & Burling. *Clean Water Act of 1977* (1977) ("We have contended that currently available control technologies are not practicable, because there is no economically feasible process available for BOD reduction. By applying enough resources, to be sure, there is at least the theoretical possibility of obtaining the result demanded by EPA. But the cost increase resulting therefrom would surely reduce demand for our product and could possibly put the entire line and thus the manufacturing plant out of business."). But imposing more stringent ELGs on wastewater already generated by the source affords no such choice. Wastewater retained in the treatment system designed to meet prior ELGs cannot be held indefinitely in most cases. It must be discharged, even if the facility in question shuts down and has no further revenue to fund expensive additional technology. In other words, facilities that chose to continue operations after adoption of the 1982 ELGs made that choice knowing they would have to meet the 1982 ELGs for any wastewater they generated and retained in the technologies they built to meet those ELGs, even after they ceased operations. But they did not know, and could not have anticipated, that they would have new and more stringent ELGs for that wastewater. EPA has not considered nor, to UWAG's knowledge, has any court addressed this issue.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 135

Comment Excerpt:

B. EPA's Decision to Exclude Legacy Wastewater and Combustion Residual Leachate from this Rulemaking Is Appropriate Because the Agency Needs to Collect Important Information Before It Can Proceed with Any Rulemaking on Those Waste Streams.

As EPA notes in the preamble to its Proposal, the Fifth Circuit in *SWEPCo* vacated and remanded the BAT ELGs for legacy wastewater and leachate that EPA adopted in 2015. UWAG supports EPA's decision not to take action on legacy and leachate wastewater in this rulemaking. 84 Fed. Reg. at 64,625. Addressing legacy wastewater and leachate in this rulemaking is impractical for several reasons.

With regard to legacy wastewater, as EPA has acknowledged, the Agency lacks sufficient information to characterize legacy wastewater and leachate, which is a necessary first step in deciding whether to pursue further regulation, whether candidate technologies are available, how those will perform, and what they will cost.[267] This step is complicated by the fact that legacy wastewaters often are commingled for treatment in ways that vary widely from facility to facility. Commingling wastewater for treatment is both entirely lawful and generally more cost effective. But the nature of the resulting effluent and the availability, performance, and cost of additional technologies may be affected as a result.

The effluent characterization EPA performed to support the 2015 ELG rule focused on the characteristics of individual waste streams, such as fly ash transport water, BATW, and FGD wastewater. 2015 TDD at 10-22 – 10-23 (fly ash transport water and BATW average effluent characterization), 10-10 – 10-11 (FGD wastewater average effluent characterization). EPA did not collect a complete picture of the combined waste streams, nor did it evaluate all of the relevant factors regarding the availability, performance, and cost of technologies for treating those combined wastewaters, much less the economic impact of imposing additional ELGs on legacy wastewater in light of the other costs imposed by the ELG rule.[268] Thus, if EPA pursues further rulemaking, it must first collect and evaluate the necessary data, and that will take time.

Time is also needed to develop the necessary information for legacy wastewaters that are managed separately and not commingled. Although wastewater characterization may not be needed, EPA has not collected and considered all of the relevant information that the statute requires the Agency to consider before making a technology selection and setting limits.

In *SWEPCo*, the Court took EPA to task for concluding that effluent limits based on surface impoundments reflected BAT because the Agency lacked sufficient information to characterize legacy wastewaters that are commingled. The Court did not suggest that EPA had adequate data to characterize commingled legacy wastewater or to support a statutorily valid determination that a specific technology qualifies as BAT for legacy wastewater regardless of whether or not it is commingled. Rather, it found that EPA's decision to move forward with setting BAT based on surface impoundments was arbitrary in light of other record evidence indicating that EPA viewed surface impoundments as outdated and other technologies as both better performers and theoretically available. *SWEPCo*, 920 F.3d at 1019-22. The Court stressed that its decision did not direct EPA's choice of technology. Id. at 1020.

EPA also needs substantial information to support any BAT determination for leachate. Although EPA collected some leachate characterization data and identified potential technologies during the 2015 rulemaking, it has not prepared any fine-tuned assessment of cost or economic impact. This is particularly important for leachate because, for the first time, EPA's 2015 rule applied technology-based ELGs developed for steam electric plants to leachate from combustion residual landfills that are not located at permitted steam electric plants. 40 C.F.R. § 423.11(r). Such non-adjoining landfills may lack both the land and the infrastructure needed to support additional technologies.

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[267] See 78 Fed. Reg. at 34,461 ("EPA does not have the data to demonstrate that the technologies identified above represent BAT for legacy FGD wastewater. As such, EPA is not proposing BAT requirements associated with discharges of legacy FGD wastewater generated prior to the date established by the permitting authority…."); 80 Fed. Reg. at 67,855 n.29 ("Although EPA identified fewer than ten plants that use chemical precipitation to treat wastewater that contains, among other things, ash transport water, EPA does not have any data to characterize the effluent from these systems.").

[268] Id. at 34,444 (stating that EPA's field sampling program was conducted at "17 different steam electric plants in the United States and Italy to collect wastewater characterization data … associated with FGD wastewater, fly ash and bottom ash wastewater, and wastewater from gasification and carbon capture processes" but not mentioning combined wastewaters; see generally EPA, *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* EPA-821-R-13-002, EPA-HQ-OW-2009-0819-2257 (Apr. 2013) at 4-19 – 4-39 (illustrating the specific, individual wastewaters EPA evaluated that do not include combined wastewaters); id. at 4-42 (illustrating that EPA did not evaluate low volume waste sources, which plants typically combine with other plant wastewaters, for new or additional ELGs).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 136

Comment Excerpt:

C. EPA Should Not Delay the BATW and FGD Wastewater ELGs While it Collects Necessary Information for Legacy and Leachate Wastewater, but EPA's Analysis of the Economic Impact of Any Further ELGs for Legacy and Leachate Wastewaters Must Account for the Cumulative Impacts of All ELG Requirements.

It is important to settle the regulation of BATW and FGD wastewater now, rather than to delay those decisions while EPA evaluates legacy wastewater and leachate issues. Companies need the certainty of EPA's final decision on BATW and FGD wastewater. For BATW and FGD wastewater, facilities need to harmonize, to the extent possible, ELG retrofits with ongoing changes necessitated by the CCR rule. Delay on evaluating ELGs for legacy wastewater and leachate will make that impossible.

That said, in developing any further technology requirements for coal-fired steam electric plants, it is essential that EPA consider the cumulative economic impacts of adding those requirements to the ELGs imposed for the same facilities. The fragmented timing of EPA's rulemaking, driven by the Agency's appropriate decision to reconsider the 2015 ELGs for two waste streams and the Fifth Circuit's decision vacating the 2015 ELGs for legacy wastewater and leachate, makes this difficult but not less essential. That is how EPA has properly approached the issue in every other ELG rulemaking, including the 2015 ELG rulemaking for steam electric plants, and that is how it should continue to address the issue.

Nothing in the *SWEPCo* decision precludes this approach or authorizes a piecemeal assessment of costs and economic impact. There, the Court held that the CWA's technology based provisions do not allow EPA to decide whether or not to regulate a given waste stream based on the amount of reduction achieved by technologies applied to other waste streams or the relative environmental benefits of one source of reduction versus another. 920 F.3d at 1026-27. Nothing in the Court's decision suggests that EPA must, or even may, consider costs and economic impacts piecemeal, on a waste stream-by-waste stream basis. That issue never arose during in the *SWEPCo* case because EPA never analyzed, much less offered any conclusion about, whether the cost of imposing additional technology requirements was economically achievable. Considering costs and economic impacts piecemeal would be counterfactual, arbitrary, and inconsistent with EPA's longstanding practice.

Commenter Name: Josh Shapiro, Brian E. Frosh, Kwame Raoul, Dana Nessel, and Thomas J. Donovan, Jr.
Commenter Affiliation: Attorneys General of Maryland, Pennsylvania, Illinois, Michigan, and Vermont
Document Control Number: EPA-HQ-OW-2009-0819-8323-A1
Comment Excerpt Number: 2

Comment Excerpt:

Although federal law generally allows states to regulate the activities at issue more stringently than federal law, EPA's proposed rollbacks and deadline extensions will harm our interests in multiple respects. Groundwater and surface waters within our respective borders are interconnected
to upstream out-of-state waters, and thus vulnerable to pollution discharged outside our boundaries. Leaking and overflowing coal ash impoundments have contaminated groundwater and surface waters alike. Effluent limitation guidelines, for their part, are meant to protect the quality of surface waters, including those that flow downstream into our states. Our states thus rely on federal regulation to ensure a stable nationwide regulatory floor protecting against pollution

crossing our borders. Further, state law may pose impediments to regulating more stringently than EPA, so that the agency's actions, in practical terms, serve not just as a regulatory floor but also as a regulatory ceiling.

Commenter Name: Josh Shapiro, Brian E. Frosh, Kwame Raoul, Dana Nessel, and Thomas J. Donovan, Jr.
Commenter Affiliation: Attorneys General of Maryland, Pennsylvania, Illinois, Michigan, and Vermont
Document Control Number: EPA-HQ-OW-2009-0819-8323-A1
Comment Excerpt Number: 5

Comment Excerpt:

III. THE ELG PROPOSAL SUFFERS FROM MULTIPLE FLAWS.
Vigorous implementation of the Clean Water Act's National Pollutant Discharge Elimination System (NPDES) permitting program ensures that discharges to navigable waters comply with permits that take into account the capabilities of treatment technologies, impacts on water quality, and the Act's overall goal of protecting the nation's waters. More specifically, federal effluent limitation guidelines provide a stable regulatory floor that guides nationwide permitting and enforcement and protects our surface waters.

This regulatory floor is important to our states. The minimum nationwide standards required by the Clean Water Act protect our waters against upstream, out-of-state pollution that we cannot regulate directly. Although pollutants discharged in one state can travel downstream to the waters of another, states typically cannot apply their own water pollution laws to polluters outside their boundaries. See generally International Paper Co. v. Ouelette, 479 U.S. 481, 491-97 (1987). Robust effluent limitation guidelines protect our states by ensuring that upstream, out-of-state point source discharges are subject at least to minimum standards applicable nationwide. A strong federal regulatory floor empowers us to protect our surface waters without fear that other states will undermine these efforts. And although federal law may permit states to regulate more stringently than EPA, there may be state-law or other impediments to doing so, causing EPA's actions to serve not just as a regulatory floor but also as a regulatory ceiling.

Against that backdrop, we are broadly concerned that EPA is unduly weakening, or delaying implementation of, effluent limitation guidelines applicable to the steam electric generating sector. Here, we write to emphasize two particular aspects of the ELG Proposal that constitute unjustifiable subsidies to dirty and uneconomical coal-fired power plants, by means of carve-outs from generally applicable effluent limitation guidelines. Neither of these carve-outs rests on any distinction in the harms caused by the pollutants at issue, and both should be withdrawn.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 1

Comment Excerpt:

1. EPA's lopsided fixation on cost as justification to set laxer effluent limitations guidelines contravenes the Clean Water Act and is irrational, even by EPA's own logic.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 5

Comment Excerpt:

II. EPA's Lopsided Fixation on Cost as Justification to Set Laxer Effluent Limitations Guidelines Contravenes the Clean Water Act and Is Irrational, Even by EPA's Own Logic.

As discussed above, for a technology to qualify as the BAT under the Clean Water Act, the technology must be the "best available technology economically achievable . . . which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[44] Thus, EPA must determine that each BAT not only makes "reasonable further progress" toward eliminating the discharge of all pollutants, but that the technology is "best" at doing so. In addition to examining each BAT's effects on water pollution, the agency must consider a host of other statutory factors, including cost and non-water quality environmental effects. [45]

Examining each proposed BAT individually, as opposed to examining a bundle of proposed BATs together, is critical to honoring the Clean Water Act. The text of the Clean Water Act makes clear that the agency is to analyze the BAT factors in "the assessment of best available technology,"[46] so failure to examine these factors for each BAT violates the statute. Analyzing the effects of a bundle of BAT limitations may offer insights into an overall regulatory approach, but such a method only informs the assessment of an overall regulation, not the "assessment of best available technology." Thus, the statute's text requires that EPA consider the BAT factors with respect to each, individual BAT.

Not only is analyzing each BAT individually statutorily required; doing so is functionally necessary. Unless the agency considers the statutory factors for each BAT individually, the agency cannot be sure each BAT is valid. A simple example illustrates this point. Imagine that EPA proposed three different BATs, each for a different subcategory of power plants. Imagine further that two of the subcategory BATs make "reasonable further progress" toward reducing water pollution, but the third BAT significantly worsens water pollution. If EPA analyzes each

BAT individually, EPA will determine that the third BAT fails to make progress toward eliminating water pollution, and therefore does not qualify as BAT. But if the agency merely assesses the water pollution impact of all three BATs together without breaking out the effects of each, the agency may miss the shortcomings of the third BAT. If the other two BATs yield positive enough effects, they will mask the third BAT's negative effects. With this after-the-fact bundled analysis, the agency would fail to consider all of the countervailing factors in determining each BAT and fail to communicate each BAT's effects to the public. Accordingly, such an approach could lead to setting invalid BATs.

Because the Proposed Rule replaces the 2015 Rule, EPA must examine how each BAT affects the statutorily mandated factors relative to the 2015 regulation.[47] Thus, for any BAT the agency changes, EPA must consider not only cost relative to the 2015 Rule, but also whether the proposed BAT is the "best" for making "reasonable" progress toward total elimination of pollution, after accounting for any negative water and non-water quality effects relative to the 2015 Rule. Throughout the Proposed Rule, however, EPA focuses almost exclusively on cost to regulated industry while neglecting other statutory BAT factors. EPA discusses cost effects at the individual BAT level, but does not consider factors like effects on health or the environment at the same level. Rather, the agency only considers such effects when evaluating entire regulatory options, each of which bundles together multiple BATs. Thus, EPA provides no evidence that the agency analyzed the necessary factors for each individual BAT, nor does the agency provide the public with the necessary information to understand the effects of each BAT. As a result, the public cannot ascertain whether each proposed BAT is indeed "best" at making "reasonable further progress" toward eliminating the discharge of all pollutants.

Furthermore, EPA contradicts its own cost justifications. The agency repeatedly casts its cost concerns in terms of coal plant retirements, but elsewhere, EPA acknowledges that regulation has little effect on these retirements. These flaws are detailed here.

44 33 U.S.C. § 1311(b)(2)(A).
45 Id. § 1314(b)(2)(B).
46 Id.
47 Agencies must give a "reasoned explanation" for why they are changing policy. F.C.C. v. Fox Television Stations,
Inc., 556 U.S. 502, 515 (2009); Encino Motorcars, LLC v. Navarro, 136 S. Ct. 2117, 2126 (2016). Furthermore, preexisting policy must be built into the baseline of economic analyses. See OFFICE OF MGMT. & BUDGET, CIRCULAR A-4 at 15 (2003) (saying the baseline for economic analyses of regulations must be the agency's "best assessment of the way the world would look absent the proposed action"); EPA, GUIDELINES FOR PREPARING ECONOMIC ANALYSES at 5-1 (explaining that a baseline is "the best assessment of the world absent the proposed
regulation or policy action").

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Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 11

Comment Excerpt:

For all of its subcategory BAT limitations, EPA violates the Clean Water Act. The agency also engages in an impermissibly lopsided analysis that emphasizes the Proposed Rule's effects on compliance costs while neglecting forgone benefits.

Commenter Name: Bethany Davis Noll
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Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 13

Comment Excerpt:

4. EPA's Cost-Benefit Analysis of Regulatory Options Does Not Cure Its Failure to Consider Factors for Each BAT

Although EPA considers the health and environmental effects of four different regulatory alternatives,[74] this consideration does not cure the agency's failure to consider the statutorily mandatory factors associated with setting the BAT. As discussed above, the Clean Water Act requires EPA to consider a list of factors when setting each BAT. Rather than consider those required factors, in the Proposed Rule, EPA neglects health and environmental effects when setting individual BAT limitations and then combines these different BAT limitations together in four different regulatory alternatives. Only then does EPA examine the health or environmental effects of each option. This approach is insufficient, because the effects of some BAT limitations may mask the effects of others.

In choosing each BAT, EPA should evaluate not only a technology's effects on compliance costs relative to the 2015 Rule, but also the technology's health and environmental protections relative to the 2015 Rule. Without doing so, EPA has no way of knowing whether a particular technology is in fact the "best" for making "reasonable" progress toward eliminating pollutants, as the Clean Water Act requires. Under EPA's current approach, it is impossible to know which BAT changes are driving the results—positive or negative—for each regulatory alternative. EPA gives no indication that the agency analyzed each BAT individually, nor does the agency provide the public with the means to do so.

This approach not only defies EPA's statutory obligation, but also could lead to harmful policy outcomes. Bundling several BAT limitations together and examining them only after the fact could disguise low-performing BAT standards. One technology might fail to make any progress toward eliminating pollution, or worse still, could exacerbate pollution, and thus should not qualify as BAT. If EPA considered the environmental effects of each BAT individually, EPA could weed out low-performing BAT limitations and ensure that each BAT is indeed "best." But such harmful effects might not stand out if masked by other more effective BAT standards combined in the same regulatory option. In fact, as discussed further in Part IV, it seems likely that all of the health and environmental effects of the various BAT/PSES changes to the Proposed Rule are being masked by effects caused by the voluntary incentives program. Because EPA could so easily evaluate BAT/PSES individually, and such an analysis is necessary to evaluate each BAT limitation accurately, the agency's failure to do so is arbitrary and capricious.

For all of the above reasons, EPA's lopsided fixation on cost in setting BAT/PSES limitations guidelines violates the Clean Water Act as well as the reasoned decision making required by the Administrative Procedure Act.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 3

Comment Excerpt:

A. The Best Available Technology Is the Most Stringent Pollution Control That Is Available and Economically Achievable.

BAT represents the best available technology that is economically achievable:[15] a stringent treatment standard that has been held to represent "a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges,"[16] including "requir[ing] the elimination of discharges of all pollutants" if "such elimination is technologically and economically achievable."[17] A technology is "available" if it is in use in the industry, even if only by the best-performing plant in the industry, or if it can be demonstrated to be available through pilot studies or its use in other industries.[18] A technology is economically achievable if the costs can be reasonably borne by the industry as a whole.[19] And as discussed below, EPA is precluded from basing its determination of BAT on a cost-benefit analysis.

1. *A treatment technology is "available" even if only in use at a single plant in the industry or can be demonstrated through pilot studies or use in another industry.*

Congress intended BAT to be "technology-forcing," i.e., to drive the development and adoption of increasingly more effective pollution controls in order to "result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[20] Courts have thus recognized that Congress intended for EPA to look to the best-performing facilities in the relevant class to determine technological availability.[21] A technology need not even be in commercial use to be available, so long as the technology has been studied and demonstrated, such as through the use of pilot studies.[22] EPA may also conclude that a technology is available if it is in use in another industry, so long as it shows that that technology is transferable to the industry class for which it is establishing BAT.[23] This contrasts with the less-stringent BPT guidelines, which are based on the average of the best-performing plants.[24] In considering available technologies, EPA must consider technologies that lead to zero liquid discharges, in light of the statutory goal of eliminating water pollution.[25] Congress intended BAT to "push[] industries toward the goal of zero discharge as quickly as possible."[26]

[15] 33 U.S.C. § 1311(b)(2)(B).
[16] EPA v. Nat'l Crushed Stone Ass'n, 449 U.S. 64, 74 (1980).
[17] 33 U.S.C. § 1311(b)(2)(A).

[18] See Chem. Mfrs. Ass'n v. EPA, 870 F.2d 177, 226 (5th Cir. 1989); Am. Petroleum Inst. v. EPA, 858 F.2d 261, 265 (5th Cir. 1988); Kennecott v. EPA, 780 F.2d 445, 448 (4th Cir. 1985).
[19] Waterkeeper All., Inc. v. EPA, 399 F.3d 486, 516 (2d Cir. 2005); Rybachek v. EPA, 904 F.2d 1276, 1290-91 (9th Cir. 1990).
[20] 33 U.S.C. § 1311(b)(2)(A); see also Nat. Res. Def. Council v. EPA, 808 F.3d 556, 563-64 (2d Cir. 2015) ("Congress designed this standard to be technology-forcing, meaning it should force agencies and permit applicants to adopt technologies that achieve the greatest reductions in pollution."); Nat. Res. Def. Council v. EPA, 822 F.2d 104, 123 (D.C. Cir. 1987) (stating that "the most salient characteristic of this [CWA] statutory scheme, articulated time and again by its architects and embedded in the statutory language, is that it is technology-forcing").
[21] Chem. Mfrs. Ass'n v. EPA, 870 F.2d 177, 226 (5th Cir. 1989) ("Congress intended these [BAT] limitations to be based on the performance of the single best-performing plant in an industrial field."); see also Nat. Res. Def. Council v. EPA, 863 F.2d 1420, 1426 (9th Cir. 1988); Kennecott, 780 F.2d at 448 ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible."); cf. Riverkeeper, Inc. v. EPA, 475 F.3d 83, 107-08 (2d Cir. 2007) ("The statutory directive requiring facilities to adopt the best technology cannot be construed to permit a facility to take measures that produce second-best results . . . especially given the technology-forcing imperative behind the Act. . . .") (citations omitted), rev'd on other grounds sub nom. Entergy Corp. v. Riverkeeper, Inc., 556 U.S. 208 (2009).
[22] See Am. Petroleum Inst., 858 F.2d at 265 (stating that under BAT, "a process is deemed 'available' even if it is not in use at all"); FMC Corp. v. Train, 539 F.2d 973, 983-84 (4th Cir. 1976) (finding EPA justified in setting BAT for chemical oxygen demand based on performance data from a single pilot plant).
[23] Kennecott, 780 F.2d at 453 ("[p]rogress would be slowed if EPA were invariably limited to treatment schemes already in force at the plants which are the subject of the rulemaking."); see also Reynolds Metals Co. v. EPA, 760 F.2d 549, 562 (4th Cir. 1985).
[24] Chem. Mfrs. Ass'n, 870 F.2d at 207-08.
[25] NRDC, 822 F.2d at 123.
[26] Kennecott, 780 F.2d at 448.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 4

Comment Excerpt:

2. A treatment technology is economically achievable if the cost of adopting the technology can be reasonably borne by the industry, and EPA is precluded from basing its BAT determination on a cost-benefit analysis.

A technology is economically achievable if the "costs can be reasonably borne by the industry."[27] Congress determined that investments in pollution controls are warranted to the greatest degree possible, and therefore the inquiry is not whether the costs of a given control are "worth it" in EPA's estimation. Instead, EPA's determination of economic achievability must be guided by the Supreme Court's holding that BAT limits "represent[] a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges."[28] EPA determines BAT for categories of sources, rather than on a plant-by-plant basis,[29] and therefore considers costs to the industry as a whole.[30] While EPA must take into account the cost of achieving BAT,[31] EPA must set BAT limits based on the use of the best available technology.[32] In developing BAT guidelines, costs are to be given even less importance than in developing the less stringent BPT guidelines. Congress underscored this by including a requirement to balance costs against benefits in promulgating BPT guidelines, but omitting any cost-benefit analysis from the development of BAT guidelines.[33]

"[I]n assessing BAT, total cost is no longer to be considered in comparison to effluent reduction benefits."[34] As the D.C. Circuit has explained, Congress affirmatively rejected amendments which would have required cost-benefit balancing for BAT.[35] "Congress uses specific language when intending that an agency engage in cost-benefit analysis," and it did not allow cost-benefit analysis here.[36]

For decades, courts have rebuffed industry attempts to introduce cost-benefit analysis as a basis for EPA decision-making in the BAT process.[37] Thus, at least seven circuit courts of appeal have affirmed, in accord with the Supreme Court's decisive pronouncement in *Nat'l Crushed Stone*, that EPA cannot base BAT guidelines on cost-benefit analysis. Subsequently, in *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009), the Supreme Court affirmed that only certain Clean Water Act standards "authorize cost-benefit analysis," and that the BAT standard does not fall within this group.[38] This analysis is consistent with the long line of cases over the past forty years that have held cost-benefit analysis is not permitted in BAT standard-setting, including the Supreme Court's ruling in *National Crushed Stone*.[39]

Congress declined to premise BAT standards on cost-benefit analysis for sound policy reasons. The sponsors of the 1972 Clean Water Act amendments recognized that the costs of pollution controls are more easily quantified than the benefits; Congress understood that while the cost of compliance are "readily quantifiable," "[s]ome economic benefits can be calculated with reasonable accuracy," but many more benefits are "difficult to calculate."[40] As the costs are more easily quantified and monetized than the benefits, any cost-benefit analysis will be biased toward emphasizing costs over benefits.

[27] Waterkeeper All., Inc. v. EPA, 399 F.3d 486, 516 (2d Cir. 2005); Rybachek v. EPA, 904 F.2d 1276, 1290-91 (9th Cir. 1990) (discussing this standard).
[28] *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980).
[29] *E.I DuPont de Nemours & Co. v. Train*, 430 U.S. at 127.
[30] See *Am. Iron & Steel Institute v. EPA*, 526 F.2d 1027, 1051 (3d Cir. 1975) (cost must be considered "on a class or category basis, rather than [on] a plant-by-plant basis").
[31] 33 U.S.C. § 1314(b)(2)(B).
[32] See A*m. Iron & Steel Inst. v. EPA*, 526 F.2d at 1051; *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 204 (5th Cir. 1989).
[33] Compare 33 U.S.C. § 1314(b)(1)(B) with 33 U.S.C. § 1314(b)(2)(B).
[34] E*PA v. Nat'l Crushed Stone*, 449 U.S. 64, 71 (1980); see also *Am. Iron & Steel*, 526 F.2d at 1051-52 ("With respect to the [BAT] standards," Congress intended "that there should be no cost-benefit analysis.").
[35] See *Weyerhaeuser v. Costle*, 590 F.2d 1011, 1046 (D.C. Cir. 1978).
[36] A*m. Textile Mfrs. Inst., Inc. v. Donovan*, 452 U.S. 490, 511 (1981); see also id. at 511 n.30 (reaffirming Nat'l Crushed Stone).
[37] *See, e.g., Am. Iron & Steel Inst. v. EPA*, 526 F.2d at 1052 n.54 ("a cost-benefit analysis is not required at all" for BAT); *CPC Int'l, Inc. v. Train*, 540 F.2d 1329, 1341-42 (8th Cir. 1976) (BAT guidelines are "governed by a standard of reasonableness without the necessity of a thorough cost-benefit analysis"); *Reynolds Metals Co. v. EPA*, 760 F.2d 549, 565 (4th Cir. 1985) ("no balancing is required" for BAT); *Rybachek v. EPA*, 904 F.2d 1276, 1290-91 (9th Cir. 1990) (EPA "need not compare [control] cost with the benefits of effluent reduction"); *BP Exploration & Oil, Inc. v. EPA*, 66 F.3d 784, 799-800 (6th Cir. 1995) (rejecting industry demand for cost-

benefit analysis because BAT "does not require cost-benefit analysis" and "EPA need only find … that the cost of the technology is reasonable"); *Tex. Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) (underlining that "BAT is the CWA's most stringent standard" and must be set based not on cost-benefit analysis but on "the performance of the single, best-performing plant in an industrial field"); *Waterkeeper Alliance v. EPA*, 399 F.3d 486, 516 (2d Cir. 2005) (BAT can be set to the level which can "reasonably be borne by a given industry"); Am. Paper Inst. v. Train, 543 F.2d 328, 348 (D.C. Cir. 1976) ("Section 304(b)(2)(B) mandates no such [cost-benefit] balancing for the 1983 limitations"); *Ass'n of Pac. Fisheries v. EPA*, 615 F.2d 794, 805 (9th Cir. 1980) ("The conspicuous absence of the comparative language contained in section 304(b)(1)(B) leads us to the conclusion that Congress did not intend the Agency or this court to engage in marginal cost-benefit comparisons [for BAT].").
[38] 556 U.S. at 219-222.
[39] See id. at 222.
[40] S. Rep. 92-414 (1972), in 1972 U.S.C.C.A.N. 3668, 3713-14.

Commenter Name: Thomas Cmar
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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 5

Comment Excerpt:

III. THE PROPOSED RULE IS UNLAWFUL AND INCONSISTENT WITH THEFIFTH CIRCUIT'S RECENT DECISION IN SOUTHWESTERN ELECTRICPOWER COMPANY.

On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit in *Southwestern Electric Co. v. U.S. Environmental Protection Agency,* Case No. 15-60821, ruled in favor of environmental petitioners' legal challenges to the legacy wastewater and leachate provisions of the 2015 ELG Rule and vacated those provisions.[41] The 2019 Proposal is inconsistent with the Fifth Circuit's decision in at least three ways, as set forth below.

A. *Southwestern Electric* Held That Surface Impoundments Are Not BAT For Legacy Wastewater and Leachate, And The Same Reasoning Applies To Other Power Plant Wastestreams.

As the *Southwestern Electric* court noted, "[s]team-electric power plants generate most of the electricity used in our nation and, sadly, an unhealthy share of the pollution discharged into our nation's waters."[42] Noting that the steam-electric ELGs had not been updated since 1982, the court observed that EPA's description of those regulations as "out of date" was a "charitable understatement."[43] Specifically, the court found that the 1982 ELGs were from a "bygone era" in that they allowed coal-burning power plants to manage toxic wastewater in surface impoundments, "which are essentially pits where wastewater sits, solids (sometimes) settle out, and toxins leach into groundwater."[44] Relying on EPA's own findings from the 2015 ELG Rule, the court found that impoundments were "largely ineffective" and that regulations based on impoundments "are relics of the past" that "do not adequately control the pollutants (toxic metals and other[s]) discharged by this industry, nor do they reflect relevant process and technology advances that have occurred in the last 30-plus years."[45]

The *Southwestern Electric* court vacated the legacy wastewater and leachate provisions of the 2015 ELG Rule because EPA had purported to determine that surface impoundments were BAT for those wastestreams. In so holding, the court reaffirmed the well-established law, explained in detail in Section II - Legal Background above, that ELGs are required to be technology-forcing and establish effluent limitations for all wastestreams based on the best-performing plant in the industrial field and the most effective technologies at eliminating discharges of pollutants that are available and achievable for that industry.[46] The court emphatically rejected EPA's determination that surface impoundments are BAT for legacy wastewater or leachate, in light of EPA's findings that they are "a technology the [2015 ELG Rule] condemns as anachronistic and ineffective at eliminating pollution discharge. In other words, EPA asks us to believe that impoundments are both archaic and cutting-edge at the same time. That we cannot do."[47] Comparing surface impoundments to personal computers, the court described EPA's selection of surface impoundments as BAT in 2015 as, "[i]t was as if Apple unveiled the new iMac, and it was a Commodore 64."[48] This is even more true in 2020, because as explained below, EPA's record demonstrates that power plant wastewater treatment technology has only further improved in the last five years.

Although the Fifth Circuit's decision in *Southwestern Electric* was limited to the legacy wastewater and leachate provisions of the 2015 ELG Rule, its reasoning for why surface impoundments are not BAT is equally applicable to any power plant wastestream, given the overwhelming record that EPA itself has developed that surface impoundments are not effective at reducing discharges of pollutants to surface water, have caused widespread groundwater contamination, and that modern, more effective, and affordable alternatives are available to the industry. Overall, as the Fifth Circuit found with respect to legacy wastewater, "the record fails to explain why impoundments are BAT, if that term is to have any meaning."[49] In the 2019 Proposal, EPA does not attempt to reconsider any of these findings from 2015, nor would it have any legitimate basis to do so. Thus, the Fifth Circuit's reasoning for why surface impoundments are not BAT applies with equal force to this rulemaking as it did to the provisions of the 2015 ELG Rule that were at issue in *Southwestern Electric*. Accordingly, any attempt by EPA to determine that surface impoundments are BAT in this rulemaking would be arbitrary, capricious, and contrary to law.

[41] 920 F.3d 999 (5th Cir. 2019).
[42] Id. at 1003.
[43] Id. (citing 80 Fed. Reg. 67,838 (Nov. 3, 2015)).
[44] Id. (citing 80 Fed. Reg. at 67,840, 67,851).
[45] Id. at 1003-04, 1007, 1015, 1017-19, 1025-26 (citing 80 Fed. Reg. at 67,840); See also 80 Fed. Reg. at 67,851 ("[P]ollutants that are present mostly in soluble (dissolved) form, such as selenium, boron, and magnesium, are not effectively and reliably removed by gravity in surface impoundments."); 78 Fed. Reg. 34,432, 34,459 (June 7, 2013) ("For metals present in both soluble and particulate forms (such as mercury), surface impoundments will not effectively remove the dissolved fraction.").
[46] See generally Sw. Elec. Power Co., 920 F.3d at 1004-07, 1015-33.
[47] Id. at 1017. See also id. ("[T]he final rule describes impoundments as an outdated and ineffective pollution control technology, and yet the same rule chooses to freeze impoundments in place as BAT for legacy wastewater. That is inconsistent with the 'technology-forcing' mandate of the [Clean Water Act]."); id. at 1016 ("[H]aving rejected impoundments as BAT because they would not achieve 'reasonable further progress' toward eliminating pollution from those streams, EPA turned around and chose impoundments as BAT for each of those same streams generated before the compliance date. That paradoxical action signals arbitrary and capricious agency action."); id. at 1019 ("Far from demonstrating that impoundments are the 'best available technology economically achievable' for

treating legacy wastewater, the evidence recounted in the final rule shows that impoundments are demonstrably ineffective at doing so and demonstrably inferior to other available technologies. In light of this record, we cannot accept that an outdated, ineffective and inferior technology is BAT when applied to legacy wastewater."); id. at 1029-30 (noting that allowing surface impoundments to be the sole means for managing leachate "has resulted in numerous documented cases of drinking water pollution," and concluding that EPA's failure to require more stringent treatment technologies for leachate was a "kind of regulation-by-inertia [that] is inconsistent with the 'technology-forcing' mandate of the [Clean Water Act].").

[48] Id. at 1004.

[49] Id. at 1018 n.20.

Commenter Name: Thomas Cmar
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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 6

Comment Excerpt:

B. The 2019 Proposal Is Directly Contrary To Southwestern Electric By Proposing That Surface Impoundments Are BAT For Subcategories of the Industry.

Remarkably, in the face of the Fifth Circuit's emphatic rejection of surface impoundments in *Southwestern Electric*, EPA nevertheless proposes to once again determine that they are BAT for FGD wastewater for major subcategories of the steam-electric power industry. Specifically, as discussed in more detail below, EPA proposes to determine that surface impoundments are BAT for FGD wastewater, in all of the regulatory options that it considered for this proposed rulemaking, for a newly-created subcategory of boilers whose owners say they will retire by 2028. See Section X.B - Retirement Subcategory. EPA also proposes to determine under its preferred Option 2 that surface impoundments are BAT for FGD wastewater for another newly-created subcategory of so-called "low utilization" boilers. See Section X.D - Low Utilization Subcategory.

EPA's proposed determination that surface impoundments are BAT for any subcategories of the industry is directly contrary to *Southwestern Electric*. As discussed above, the Fifth Circuit emphatically rejected the proposition that surface impoundments – which it described as "relics of the past" from a "bygone era" – are BAT for legacy wastewater and leachate, and this reasoning applies with equal force to the other power plant wastestreams at issue in this rulemaking.

EPA's flimsy attempt to reconcile with Southwestern Electric its determination that surface impoundments can be BAT for subcategories of the industry is arbitrary and capricious. EPA states in the preamble to the 2019 Proposal that the Fifth Circuit "left open the possibility that surface impoundments could be used as the basis for BAT effluent limitations so long as the Agency identifies a statutory factor, such as cost, in its rationale for selecting surface impoundments."[50] This statement grossly mischaracterizes the Fifth Circuit's opinion, which was based on well-established law (discussed above in Section II - Legal Background) on the BAT standard that EPA fails to adhere to in the 2019 Proposal. Specifically, as the Fifth Circuit recognized, a lawful BAT determination must be "'technology-forcing, meaning it should force agencies and permit applicants to adopt technologies that achieve the greatest reductions in pollution.'"[51] Further, a lawful BAT determination must "'be based on the single-best performing plant in an industrial field' . . . 'not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible.'"[52]

And while EPA is correct that it is required to consider cost in making a BAT determination, any sort of balancing of costs against benefits is not permitted.[53] Rather, EPA must set BAT at a level that is affordable to the industry as a whole, but that requires industry to invest in pollution controls reflecting "'a commitment of the maximum resources economically possible to the ultimate goal of eliminating all pollutant discharges,' which was the intent of Congress in enacting BAT standards in the first place."[54] Applying these standards to EPA's record, the Fifth Circuit concluded that surface impoundments do not represent the technology in use at the best performing plant in the industrial field in light of their well-documented lack of effectiveness and the availability and affordability of superior alternatives.[55]

EPA's suggestion in the preamble to the 2019 Proposal that it is free to disregard the Fifth Circuit's analysis of the record – which again, as to surface impoundments, has not changed in any material respect since 2015 – simply because it is now more explicitly invoking cost as a factor than it did in the 2015 ELG Rule, is completely meritless in light of the Fifth Circuit's detailed findings of the failure of surface impoundments to meet the BAT standard. *Southwestern Electric* reaffirmed and relied on over forty years of precedent concerning how EPA may consider cost consistent with the BAT standard, and EPA's statements about cost in the preamble to the 2019 Proposal are contrary to that well-established law, as well as arbitrary and capricious.

[50] 84 Fed. Reg. 64,620, 64,639 (Nov. 22, 2019).
[51] *Sw. Elec. Power Co.,* 920 F.3d at 1005 (quoting Nat. Res. Def. Council v. EPA, 808 F.3d 556, 563-64 (2d Cir. 2015)). See also id. ("The D.C. Circuit accurately described this aspect of the Act's scheme as 'technology-forcing,' meaning it seeks to 'press development of new, more efficient and effective [pollution-control] technologies.'") (quoting *Nat. Res. Def. Council v. EPA*, 822 F.2d 104, 123 (D.C. Cir. 1987)).
[52] Id. at 1018 (quoting *Tex. Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) (internal quotation marks omitted) & *Kennecott v. EPA*, 780 F.2d 445, 448 (4th Cir. 1985)). See also id. at 1025 (emphasizing that BAT cannot merely be set as the average of best-performing plants, but must be based on the single best-performing plant in the industrial field).
[53] Id. at 1007.
[54] Id. at 1030 (quoting *EPA v. Nat'l Crushed Stone Ass'n,* 449 U.S. 64, 74 (1980)).
[55] Id. at 1015-22, 1025-26, 1029-33.

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
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Comment Excerpt:

C. The 2019 Proposal Is Arbitrary and Capricious Because It Moves Forward With Changes That Weaken the 2015 ELG Rule And Are Not Legally Required While Failing To Address A Court Order To Strengthen the Rule.

The 2019 Proposal is also inconsistent with *Southwestern Electric*, and therefore arbitrary and capricious, because it proposes to make changes to weaken the 2015 ELG Rule while failing to respond to the Fifth Circuit's order that the legacy wastewater and leachate provisions of the Rule must be strengthened in order to comply with the CWA. The 2019 Proposal mentions the *Southwestern Electric* vacatur only in passing, stating only that "EPA plans to address this vacatur in a subsequent action."[56] EPA has yet to provide any timeframe for taking action in response to *Southwestern Electric*, seeking instead to prioritize this rulemaking over timely compliance with the Fifth Circuit's order.

By contrast, none of the changes in the 2019 Proposal are legally required, resulting instead from EPA's voluntary decision in 2017 to reconsider portions of the 2015 ELG Rule in response to petitions for reconsideration from the Utility Water Act Group and the U.S. Small Business Administration. However, as a coalition of public health and environmental advocates explained in comments submitted to EPA in July 2017 on the proposed Postponement Rule, those reconsideration petitions were lacking in merit and provided no basis for EPA to reconsider the 2015 ELG Rule.[57] This is only underscored by the fact that the 2019 Proposal does not directly discuss any of the primary issues set forth in the reconsideration petitions, nor even discuss the substance of those petitions.[58] And although the Fifth Circuit agreed to stay litigation of industry claims challenging the 2015 ELG Rule pending this rulemaking, neither EPA nor the court has ever found those industry claims to have any merit – unlike the deficiencies in the legacy wastewater and leachate provisions that were adjudicated in *Southwestern Electric*. Nevertheless, EPA has chosen to move forward with the 2019 Proposal over seven months after the Fifth Circuit issued a decision in *Southwestern Electric*, without also proposing to address the Fifth Circuit's vacatur of the 2015 ELG Rule's legacy wastewater and leachate provisions.

This is arbitrary and capricious. EPA is not free to ignore court orders simply because the agency might prefer, for political or other reasons, not to respond to them in a timely manner. As the D.C. Circuit has noted, "a reasonable time for agency action is typically counted in weeks or months, not years."[59] Although it is not uncommon for agencies to take a year or more to respond to a court order, under the circumstances here it is patently unreasonable – and contrary to EPA's mission to protect public health and the environment – for the agency to delay commencement of a court-ordered rulemaking to strengthen provisions of the 2015 ELG Rule in favor of a discretionary rulemaking that is not legally required, is contrary to the CWA in numerous respects as discussed in detail throughout these comments, and whose primary purpose is to benefit private industry at the expense of health and environmental benefits to the broader public.

[56] 84 Fed. Reg. at 64,625.
[57] Comments of Sierra Club et al., Docket ID No. EPA-HQ-OW-2009-0819-6654 (July 6, 2017).
[58] See Utility Water Act Group petition for reconsideration of 2015 ELG Rule (Mar. 24, 2017), Docket ID No. EPA-HQ-OW-2009-0819-6478; U.S. Small Business Administration petition for reconsideration of 2015 ELG Rule (Apr. 5, 2017), Docket ID No. EPA-HQ-OW-2009-0819-6481.
[59] In re: *Am. Rivers & Idaho Rivers United*, 372 F.3d 413, 419 (D.C. Cir. 2004).

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 26

Comment Excerpt:

Finally, EPA's statements in the 2019 Proposal that the statutory factors of process changes and cost justify it not selecting wet closed-loop systems as BAT for bottom ash transport water[106] are without merit. As discussed above in Sections II – Legal Background and III – Southwestern Electric, EPA must set BAT at a level that is affordable to the industry as a whole, but that requires industry to invest in pollution controls reflecting "'a commitment of the maximum resources economically possible to the ultimate goal of eliminating all pollutant discharges,' which was the intent of Congress in enacting BAT standards in the first place."[107] And while EPA is correct that it is required to consider cost in making a BAT determination, any sort of balancing of costs against benefits is not permitted.[108] Similarly, while EPA can consider process changes as a factor in making a BAT determination, consideration of that single factor (or any other single BAT factor) on its own cannot eclipse the over-arching goal of the BAT standard, which is to be "technology-forcing, meaning it should force agencies and permit applicants to adopt technologies that achieve the greatest reductions in pollution."[109] EPA's suggestion that individual BAT factors might allow it to ignore the requirements of the overall standard is without any support in the CWA or the decades of case law interpreting BAT.

[106] 84 Fed. Reg. at 64,635.
[107] *Sw. Elec. Power Co. v. EPA*, 920 F.3d 999, 1030 (5th Cir. 2019) (quoting *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980)).
[108] Id. at 1007.
[109] *Nat. Res. Def. Council v. EPA*, 808 F.3d 556, 563-64 (2d Cir. 2015); see also *Nat. Res. Def. Council, Inc. v. EPA*, 822 F.2d 104, 123 (D.C. Cir. 1987) (stating that "the most salient characteristic of this [CWA] statutory scheme, articulated time and again by its architects and embedded in the statutory language, is that it is technology-forcing").

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 45

Comment Excerpt:

VII. EPA CANNOT WEAKEN THE BEST AVAILABLE TECHNOLOGY REQUIREMENTS FOR FGD WASTEWATER

As explained above, the record makes clear that a zero-discharge standard is BAT for FGD wastewater. EPA concedes that membrane filtration and other zero-discharge technologies are economically feasible and actually in use in the industry, and therefore "available." If the Clean Water Act's BAT mandate has any meaning, EPA must require EGUs to eliminate the discharge of FGD wastewater through the use of economically and technically achievable membrane technology.[167]

[167] See Section VI – Zero Discharge FGD.

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 64

Comment Excerpt:

B. The Clean Water Act Prohibits EPA from Extending The Compliance Date for Revised Effluent Limitations Guidelines by Eight Years Following The Final Rule.

Assuming that EPA finalizes the proposed revisions to the ELG in 2020, facilities taking advantage of the VIP will have eight years to meet the effluent limitations applicable to such facilities. This extension violates the plain language of the Clean Water Act.

The Act requires dischargers of specified toxic pollutants to achieve "compliance with [BAT] effluent limitations . . . as expeditiously as practicable but in no case later than three years after the date such limitations are promulgated . . . ."[223] EPA thus proposes to authorize a discharger of FGD wastewater to blow by this statutory requirement by five years in exchange for asserting that the facility will meet more stringent requirements than might otherwise apply. The statute plainly prohibits that approach.[224]

EPA will no doubt respond to this comment by claiming that the three-year deadline for ELG compliance only applies to the first set of BAT limitations for toxic pollutants from an industry. That argument relies on the fact that the compliance deadline provision in section 301(b)(2)(C) of the Act also states that compliance must be achieved "in no case later than March 31, 1989," an interpretation accepted by the U.S. Court of Appeals for the Fifth Circuit in litigation over EPA's rule delaying the compliance dates of the 2015 ELGs.[225] However, that decision was legally erroneous and, even it were correctly decided on the law, does not properly apply to the facts of the present regulation.

The plain text of section 301(b)(2)(C) specifies that compliance must be achieved no later than three years following the promulgation of toxic pollutant BAT limitations and there is nothing ambiguous about that language. That the same section also contains a provision – establishing March 1989 as the presumptive outside date for initial limitations – does not render the otherwise-applicable three-year language (or, for that matter, the otherwise-applicable "as expeditiously as practicable" language) unclear. To the contrary, it underscores that Congress viewed compliance with BAT limitations on toxic pollutants as an urgent priority, to be met quickly after such limitations were promulgated. Moreover, section 301(d) reinforces this approach, demanding that effluent limitations be reviewed and updated as appropriate every five years, "pursuant to the procedure established under" section 301(b)(2);[226] this provision reveals Congressional intent to continually and promptly move industries toward better pollution controls and, by incorporating the procedures of subsection (b), directs EPA to follow the compliance deadlines for BAT limitations on toxic discharges in subsection (b)(2)(C), minus the outdated reference to March 1989.

Even if one were to accept – which we do not – the interpretation that the three-year deadline for BAT limitations on toxic discharges only apply to the initial promulgation of such limitations, the limitations established by this rulemaking for FGD wastewater qualify as such initial limits. In the 1982 steam electric ELG rule, EPA expressly "reserv[ed] effluent limitations for four types of wastewaters for future rulemaking," including "[f]lue gas desulfurization waters," not setting any effluent limitations at all specific to those wastestreams.[227]

The legislative history of the Act supports this interpretation as well. Although Congress initially set a March 31, 1989 deadline for compliance with BAT effluent limitations, with the intention that EPA would promulgate ELGs setting forth those BAT limits before the deadline, Congress also amended section 309 of the Act to allow EPA to address issues involving compliance with BAT limits through enforcement discretion.[228] Based on this legislative history, the U.S. Court of Appeals for the Fifth Circuit held that EPA lacks discretion to extend compliance deadlines for BAT limits beyond the three-year outer bound set forth in the statute.[229]

Finally, in a separate subsection of section 301, Congress spoke directly to the notion of providing an extended compliance date for more aggressive control technologies, further establishing that EPA lacks the authority to invent a compliance date of its own choosing for the VIP. Subsection (k) specifies that a facility that, among other things, installs "an innovative control technique that has a substantial likelihood for enabling the facility to comply with the applicable effluent limitation by achieving a significantly greater effluent reduction than that required by the applicable effluent reduction and moves toward the national goal of eliminating the discharge of all pollutants," may receive a compliance date "no later than two years after the date for compliance with such effluent limitation which would otherwise be applicable . . . if it is also determined that such innovative system has the potential for industrywide application."[230] This provision plainly provides that Congress intended that, should EPA believe the promotion of advanced controls warrants additional compliance time, the agency both must make certain findings in order to do so and must limit the supplemental time to two years at most.[231] In the case of the VIP, EPA has done neither. Therefore, the plain language of the Clean Water Act forbids EPA's proposed VIP.

[223] 33 U.S.C. § 1311(b)(2)(C).
[224] We acknowledge that the 2015 ELG Rule also allowed extensions of the compliance deadline up to December 31, 2023. 80 Fed. Reg. at 67,854. But EPA's having done something previously does not make it lawful. Moreover, unlike the proposal, the 2015 ELG Rule at least required compliance for all effluent limitations "as soon as possible" on or after the three-year deadline. Id. it lawful. Moreover, unlike the proposal, the 2015 ELG Rule at least required compliance for all effluent limitations "as soon as possible" on or after the three-year deadline. Id.
[225] See *Clean Water Action v. EPA*, 936 F.3d 308, 316-17 (5th Cir. 2019) (accepting EPA argument that deadlines only apply to initial promulgation).
[226] 33 U.S.C. § 1311(d).
[227] 47 Fed. Reg. 52,290, 52,291 (Nov. 19, 1982).
[228] See 33 U.S.C. § 1319(a)(5)(A) ("Any [enforcement] order issued . . . shall specify a time for compliance . . . not to exceed a time the Administrator determines to be reasonable in the case of a violation of a final deadline, taking into account the seriousness of the violation and any good faith efforts to comply with applicable requirements."); see also H.Rep. No. 99-1004, at 115-16 (1986) (Conf. Rep.) ("If dischargers in an entire category are unable to meet the March 31, 1989, deadline provided in the conference substitute as a result of the Administrator's failure to promulgate effluent limitations in sufficient time to allow for compliance by such date, non-compliance resulting from the Administrator's delay can be dealt with under EPA's current post-1984 deadline enforcement policy.").
[229] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 242 (5th Cir. 1989).

[230] 33 U.S.C. § 1311(k).
[231] E.g., 53 Fed. Reg. 18,764, 18,784 (May 24, 1988) (utilizing subsection (k) in the ore mining and dressing ELG).

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 78

Comment Excerpt:

X. EPA HAS NOT JUSTIFIED ANY NEW SUBCATEGORIES FOR THE INDUSTRY.

A. EPA's Authority to Create Industry Subcategories Is Constrained by the Clean Water Act.

EPA has limited authority to create industry subcategories when promulgating industry-wide ELGs. Because EPA would exceed that authority by creating the three new subcategories that it has proposed in the rule, EPA must eliminate those subcategories from the final rule.

The Clean Water Act requires EPA to determine the best available technology (BAT) for controlling pollution from "categories or classes" of industries.[275] Although the Act does not explicitly authorize EPA's creation of industry *sub*categories, courts have upheld EPA's decision to do so when based on consideration of the same statutory factors that EPA must consider in determining BAT.[276] Those factors are the "age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate."[277] In determining BAT for a category or subcategory of industry dischargers, EPA must consider *all* of these factors; EPA "is not free to ignore any individual factor entirely."[278]

EPA is not required to create subcategories for groups of plants unless "they are so fundamentally different from other plants" in the same industry that they cannot achieve the same effluent limitations.[279] As the Court of Appeals for the Fifth Circuit has explained, EPA's "task is to establish numerical standards limiting effluent pollution;" "[i]f plants can meet the same limitation, they need not be subcategorized simply because they are different."[280] This presumption against subcategorization is consistent with the Clean Water Act's emphasis on uniformity.[281]

[275] 33 U.S.C. § 1314(b)(2).
[276] See, e.g., *Chem. Mfrs. Ass'n v. Nat. Res. Def. Council, Inc.*, 470 U.S. 116, 130-31 (1985); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 214-15 (5th Cir. 1989).
[277] 33 U.S.C. § 1314(b)(2)(B).
[278] T*ex. Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 934 (5th Cir. 1998).
[279] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 214-15.
[280] Id. (internal quotations omitted).
[281] See *E. I. du Pont de Nemours & Co. v. Train*, 430 U.S. 112, 133-36 (1977) (holding that Section 301 of

the Act authorizes EPA to achieve the "statutory goal" of setting "uniform" effluent limitations for categories of plants rather than plant-by-plant limitations); see also *Nat. Res. Def. Council, Inc. v. Train*, 510 F.2d 692, 709-10 (D.C. Cir. 1974) (explaining that Congress intended ELG requirements to "safeguard against industrial pressures by establishing a uniform 'minimal level of control imposed on all sources within a category or class'").

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Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 2

Comment Excerpt:

I. BACKGROUND

In this proposal, EPA once more seeks to subject communities and their clean water to more pollution and risks from the primitive operation of the worst functioning coal-fired plants. EPA is acting as though it is entirely ignorant of how communities, states, and utilities are reacting to EPA's failures. In determining the best available technology to reduce pollution, EPA would allow utilities not to operate existing and installed pollution control systems. EPA's proposal directly contravenes the Clean Water Act, backslides on existing permit requirements, and discards available technologies that utilities are using today.

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Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 9

Comment Excerpt:

II EPA'S PROPOSAL TO WEAKEN THE EFFLUENT LIMITATIONS GUIDELINES VIOLATES THE BAT STANDARD.

The Clean Water Act's central mechanism for achieving its ambitious goal of eliminating all pollution is the promulgation and imposition of increasingly stringent effluent limits. EPA's attempt to backslide by weakening the existing effluent limits violates the Clean Water Act and the BAT standard.

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Comment Excerpt Number: 15

Comment Excerpt:

These proposals are directly contrary to the requirements of the Act, which requires forward progress.

"Few laws have shouldered a weightier burden" than the Clean Water Act, [2] which established that "it is the national goal that the discharge of pollutants into navigable waters be eliminated[.]"[3] To that end, the Act requires EPA to set "effluent limitation guidelines," which are "technology-based rather than harm based."[4] EPA's effluent limits under the BAT standard must "result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[5]

Because the "best available technology" standard is dynamically tied to the best performing facility, the Act anticipates revisions, when appropriate, to become only more stringent. Those revisions, like all BAT standards, must "result in reasonable further progress" toward the elimination of all discharges.

Thus, the text of the Act requires that when EPA finalizes a rule setting BAT in 2020, it must make reasonable further progress beyond the limits set in the 2015 Rule and towards eliminating pollution from waters of the United States. While EPA has delayed some of the compliance dates in the 2015 ELG rule, it is beyond question that the rule was finalized,[6] and established BAT for various categories of point sources. BAT analysis requires each new ELG to result in reasonable further progress in comparison to the prior standard.

Backsliding to a less stringent "best available technology" standard is not progress, because allowing more pollution cannot be forward movement toward the elimination of all pollution from waters of the US. A less stringent standard certainly is not further progress toward that goal, because it does not extend or accelerate that movement toward zero discharge. To achieve reasonable further progress, each new BAT standard must bring us closer to zero discharge, covering at least as many pollutants with at least the same level of stringency as the prior standard.

2 *Sw. Elec. Power Co. v. EPA*, 920 F.3d 999, 1004 (5th Cir. 2019).
3 33 U.S.C. § 1251(a)(1).
4 *Tex. Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 927 (5th Cir. 1998).
5 33 U.S.C. § 1311(b)(2)(A).
6 That EPA styles its current proposal as a "reconsideration" is irrelevant. Regulated industry petitioned for reconsideration of the 2015 ELGs in 2017 "pursuant to 5 U.S.C. § 553(e) for a rulemaking to reconsider the [2015 ELGs]." The Administrative Procedure Act provides, "Each agency shall give an interested person the right to petition for the issuance, amendment, or repeal of a rule." 5 U.S.C. § 553(e). "[T]his provision simply establishes the right to petition an agency to initiate a new rulemaking, including a rulemaking to amend or rescind a final rule prescribed by an agency, that requires full notice and comment." *NRDC v. Abraham*, 355 F.3d 179, 203 (2d Cir. 2004) (emphasis original). The APA "makes no distinction . . . between initial agency action and subsequent agency action undoing or revising that action." *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42 (1983). For this reason, the Fifth Circuit considered EPA's 2017 "delay rule" a new rulemaking, subject to the same standard of review as any other rulemaking. *Clean Water Action v. EPA*, 936 F.3d 308, 312–13 (5th Cir. 2019). A "reconsideration" is a new rulemaking, and it does not affect the finality of prior rulemakings.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
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Comment Excerpt:

Weakening effluent limitations is antithetical to the plain language and clear intent of the Clean Water Act. "After all, BAT is supposed to be the CWA's most stringent standard for setting discharge limits for existing sources."[7] The CWA requires EPA to progressively tighten pollution limits over time with BAT:[8] "BAT is the gold standard for controlling water pollution from existing sources. By requiring BAT, the Act forces implementation of increasingly stringent pollution control methods."[9] As the Supreme Court has explained, "a BAT must achieve 'reasonable further progress' towards the Act's goal of eliminating pollution[.]"[10] By tripling the amount of selenium pollution allowed by the ELG, allowing unnecessary bottom ash wastewater discharges, allowing higher mercury discharges and unlimited selenium and nitrate/nitrite discharges from a so-called "high flow" facility, and proposing to allow primitive, poorly-performing unlined impoundments as BAT for certain facilities, EPA proposes to go backward instead of forward. "EPA has contravened the plain language of the CWA, which defines BAT as the technology that 'will result in reasonable further progress' toward pollutant discharge elimination."[11]

[7] *Sw. Elec. Power Co.*, 920 F3d at 1016.
[8] 33 USC § 1311(b).
[9] *Sw. Elec. Power Co.*, 920 F.3d at 1004 ("The Act therefore mandates a system in which, as available pollution control technology advances, pollution-discharge limits will tighten."); *see also, EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 69 (1980) (the Act "provides for increasingly stringent effluent limitations") (citing 33 U.S.C. § 1311(b)); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 196 (5th Cir. 1989), *decision clarified on reh'g*, 885 F.2d 253 (5th Cir. 1989) (the Act requires compliance with "technology-based pollutant-effluent limitations that, in time, will become more stringent") (citing 33 U.S.C. §§ 1311(b), 1314(b)).
[10] *Sw. Elec. Power Co.*, 920 F.3d at 1006 (quoting Nat'l Crushed Stone, 449 U.S. at 75, 101 S.Ct. 295). 11 Sw. Elec. Power Co., 920 F.3d at 1016.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 17

Comment Excerpt:

III FGD WASTEWATER

a. The BAT Standard Does Not Allow EPA to Use a "Voluntary Incentive Program" to Avoid Requiring the Best Available Technology.

EPA has no authority to substitute a "voluntary incentive program" for the requirements of the BAT standard. Where, as here, a technology such as membrane filtration is significantly more effective at eliminating pollution and is affordable for the industry, the Clean Water Act requires that EPA use it as the best available technology to set nationwide effluent limits for the industry. There is no basis in the statute for EPA's proposal to allow polluters to decide whether or not to comply with effluent limits based on membrane filtration.

Indeed, by doing so, EPA is purporting to let utilities themselves create new subcategories within the industry: those that choose to comply with the less-protective Option 2 standard, and those that choose to comply with the more-protective VIP standard. This approach is directly contrary to the Clean Water Act, which mandates that industry comply with effluent limits set by EPA based on the single best-performing facility. To make compliance voluntary undermines BAT and the entire structure of the Clean Water Act.

The current proposal is particularly problematic because EPA is saying that a better technology is affordable for the industry, yet is refusing to mandate it.

...

EPA cannot make compliance voluntary when, as explained below, membrane filtration is the best available technology economically achievable.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
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Comment Excerpt:

Legally, EPA is wrong to argue that it may set BAT based on the conclusory assumption that additional pollution reductions would be "de minimis." As explained in Part II above, EPA's argument is contrary to the language in the Clean Water Act defining BAT, which requires "best available technology economically achievable for such category or class, which ***will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants***[.]"[56] "[T]he Administrator [of EPA] must 'require industry, regardless of a discharge's effect on water quality, to employ defined levels of technology to meet effluent limitations.'"[57]

In support of its argument EPA cites *American Petroleum Institute v. EPA*, which says, in dicta, that "EPA would disserve its mandate were it to tilt at windmills by imposing BAT limitations which removed de minimis amounts of polluting agents from our nation's waters, while imposing possibly disabling costs upon the regulated industry."[58] This quote from *American Petroleum Institute* is factually inapposite here because, as explained above, the reductions are not de minimis. The "de minimis" dicta in *American Petroleum* is not the correct legal standard, but in any event, it still would not justify basing FGD limits on a technology less than BAT because the 2015 Rule in no way represents "the point of regulation ad absurdum" described by the Fifth Circuit: as explained above, the pollution reductions achieved by the 2015 Rule are not "miniscule" and the cost of compliance would not be "disabling" upon the regulated industry.[59] Indeed, at its Belews Creek, Allen, Roxboro, and Marshall sites, Duke Energy has installed and is operating new technology to control pollution without incurring "disabling costs."[60]

[56] 33 U.S.C. 1311(b)(2)(A) (emphasis added).
[57] *Sw. Elec. Power Co.*, 920 F.3d at 1005 (quoting *Am. Petroleum Inst. v. EPA*, 661 F.2d 340, 344 (5th Cir. 1981)); see also *Tex. Oil & Gas*, 161 F.3d at 927 (ELGs are "technology-based rather than harm-based" insofar as they "reflect the capabilities of available pollution control technologies to prevent or limit different discharges rather than the impact that those discharges have on the waters").
[58] *Am. Petroleum Inst. v. E.P.A.*, 787 F.2d 965 (5th Cir. 1986).
[59] Id. at 972-973.
[60] Moreover, if an individual plant faced truly faced "disabling costs," the Clean Water Act provides a remedy for permit applicants in "unique permitting situations," and allows variances under certain circumstances, including "economic capability of the applicant." See 33 USC § 1311; 40 CFR §124.62(b)(1); EPA, NPDES Permit Writers' Manual, Chapter 10, available at https://www3.epa.gov/npdes/pubs/chapt_10.pdf (Attachment 11).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 37

Comment Excerpt:

1. EPA's Rationale Violates the Clean Water Act's Requirements. [Bottom Ash Wastewater]

EPA offers two rationales for its proposed weakening of the BAT standard: process changes and cost.[86] Neither justifies EPA's approach.

The Clean Water Act requires that polluters use the best available technology economically achievable to eliminate their discharge of pollutants.[87] As EPA acknowledges, "BAT is intended to reflect the highest performance in the industry."[88] In *Southwest Electric Power Co.*, the Fifth Circuit reaffirmed that "BAT limitations must 'be based on the performance of the ***single best-performing plant*** in an industrial field.'"[89] In other words, if the technology is being applied by any plant in the industry, it is achievable.[90]

a. Cost

As these standards should make clear, cost cannot be the basis for adopting a technology less protective than the non-discharge systems that are already available for bottom ash handling. Cost is "not a factor to be given primary importance"—even for the "best practical technology" standard, which (unlike BAT) contemplates a cost-benefit analysis; cost necessarily plays an even lesser role in the BAT standard.[91] In assessing BAT, "total cost is no longer to be considered in comparison to effluent reduction benefits."[92] Instead, the cost of a given technology may be considered only as to whether it can be reasonably borne by the industry.[93]

Here, EPA's analysis violates the BAT standard by selecting technology based on cost, even though it is clear better protections are economically achievable. Moreover, to the extent EPA is relying on the "benefit-cost analysis" it has attached to the proposed rule, such analysis also cannot justify the proposed weakening of BAT, as the plain text of the rule states and the Supreme Court has confirmed, the BAT standard does not allow such an analysis.

There is no question that dry handling and other true non-discharge systems are economically achievable and that their cost can be borne by the industry. EPA confirms that it "does not find" the cost of closed-loop handling systems "to be economically unachievable."[94] In other words, EPA does not dispute that such systems are the best available technology economically achievable.

[86] See id. at 64,635.
[87] 33 U.S.C. § 1311(b)(2)(A).
[88] 84 Fed. Reg. at 64,624.
[89] 920 F.3d at 1006 (quoting *Chem. Mfrs. Ass'n*, 870 F.2d at 226; see also *Am. Paper Inst.*, 543 F.2d at 346 (BAT should "at a minimum, be established with reference to the best performer in any industrial category.").
[90] See *Kennecott*, 780 F.2d at 448 ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible.").
[91] *Am. Iron & Steel Inst.*, 526 F.2d at 1051.
[92] *Nat'l Crushed Stone*, 449 U.S. at 71.
[93] *Chem. Mfrs. Ass'n*, 870 F.2d at 262; *accord Riverkeeper, Inc. v. U.S. E.P.A.,* 358 F.3d 174, 195 (2d Cir. 2004) (same); *FMC Corp.*, 539 F.2d at 978–79 ("The Act's overriding objective of eliminating ... the discharge of pollution into the waters of our Nation indicates that Congress, in its legislative wisdom, has determined that the many intangible benefits of clean water" take precedence over cost considerations).
[94] 84 Fed. Reg. at 64,635.

Commenter Name: Megan Kimball
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Comment Excerpt:

b. Process Changes

EPA also attempts to justify its approach "based on its discretion to give particular weight to . . . process changes," citing utilities' obligation to stop using their impoundments for all wastestreams and potential maintenance issues with closed loop bottom ash handling systems that it claims could result,[95] but these arguments lack support.

EPA asserts that ceasing other flows into coal ash impoundments in preparation for closure "compound[s]" the challenges of operating non-discharge bottom ash systems,[96] but Duke Energy has never made such a claim in North Carolina. Duke Energy is installing lined retention basins for its other waste streams,[97] and other utilities can do the same.

EPA states that some facilities may use their bottom ash systems to treat other waste streams that previously were routed to ash ponds, resulting in increased maintenance problems. [98] EPA argues this practice justifies the proposed weakening of the standards. But the Fifth Circuit rejected such an approach just last year. The court explained that BAT must be set only in reference to the waste stream in question, not others.[99]

Here, utilities' decisions to operate their systems in ways that make them less effective at their intended purpose—bottom ash handling—provides no legitimate basis for weakening the bottom ash handling requirement.

[95] Id.
[96] See id.
[97] See, e.g., Attachments 12 at 2 (Outfall 005) and 30 at 2 (Outfall 006); NC DEQ, NPDES Permit NC0038377 Mayo Steam Electric Generating Plant, 2 (Outfall 002A) (July 13, 2018), available at https://files.nc.gov/ncdeq/Water+Quality/NPDES+Coal+Ash/2014+Duke+Energy+Renewals+and+Modifications/Mayo/MAYO-38377-final-permit-signed-2018.pdf (Attachment 36).
[98] See 84 Fed. Reg. at 64,635.
[99] *Sw. Elec. Power Co.*, 920 F.3d at 1027 ("the agency has explicitly factored into its BAT determination the regulation of wastestreams other than leachate, which contravenes the plain text and structure of the Act.").

Commenter Name: Megan Kimball
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Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 39

Comment Excerpt:

Process Changes

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And contrary to EPA's unsupported claim, there is no reason why requiring utilities to properly manage their wastewater streams "could also result in the prolonged use of unlined surface impoundments."[100] Indeed, this claim makes no sense, especially when EPA is attempting to rely on the proposed CCR Rule deadline to cease routing wastestreams to impoundments as a basis for weakening the bottom ash technology standard.

[100] 84 Fed. Reg. at 64,635.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 64

Comment Excerpt:

b. The Act Prohibits EPA from Creating Single-Facility, Cost-Based BAT Subcategories

Even if a subcategory of one were permissible, which it is not, a subcategory of one based on cost is flatly inconsistent with the Clean Water Act.

The costs of an individual facility are not relevant in setting BAT. The Act requires BAT to be "economically achievable for a category or class of point sources."[209] As the 1972 conference report explains, Congress directed EPA to "make the determination of the economic impact of an effluent limitation on the basis of classes and categories of point sources, as distinguished from a plant-by-plant determination."[210] Courts have consistently found that BAT "does not refer to any individual plant" in assessing economic achievability.[211]

Congress structured the Clean Water Act to prohibit EPA from setting effluent limitations for toxic pollutants[212] based on an individual facility's costs. BAT sets effluent limitations based on industry-wide costs, not individual facility costs.[213] Section 301(c) modifications allow EPA to modify an individual facility's effluent limitations based on facility-specific costs.[214] But Congress prohibited such modifications for toxic pollutants, like those at issue here.[215] The FDF variance allows individual accommodation based on any factor "other than cost."[216] FDF variances are unavailable here because cost is the only factor EPA cites to support subcategorization.

Legislative history confirms that the Act does not authorize EPA to create single-facility, cost-based BAT subcategories.

When codifying the FDF variance, Congress reiterated its intent to prohibit single facility, cost-based subcategories. Regarding the FDF variance, the 1986 conference report stated, "The bill specifically excludes consideration of costs, independent of other eligible factors, as a basis for establishing a fundamental difference with regard to an individual facility."[217]

Senator Robert Stafford (R-VT), Chairman of the Environment and Public Works Committee and a member of the conference committee, explained:

If a facility faces higher individual cost than the industry average, that is a reflection of economic efficiency of the facility rather than the ability of the industry as a whole to meet the necessary pollution control costs. To establish individual effluent limits on the basis of plant-specific cost of compliance would be to vitiate the principle of industrywide minimum treatment levels. For these reasons...the conferees agreed to adopt the Senate approach and exclude the individual cost of compliance from the factors the Administrator may consider when deciding whether to grant an FDF variance to a particular facility. Although *the act does not and should not provide a mechanism to modify the requirements of an effluent guideline on the basis of fundamentally different costs at an individual facility*, section 301(c) of the act provides for modification of requirements in a case where such requirements are beyond the economic capability of the owner. . . . In addition, section 301(c) is subject to section 301(l), which prohibits the Administrator from modifying any requirement as it applies to a toxic pollutant. *This provision assures that toxic pollutants will be controlled, regardless of the economic capability of the discharger*. [218]

In short, the Clean Water Act does not authorize EPA to make single-plant, cost-based exceptions to effluent limitations for toxic pollutants, as EPA proposes to do in the High Flow Subcategory.

[209] 33 U.S.C. § 1311(b)(2)(A).
[210] Sen. Conf. Rep. No. 92-1236, at 121 (1972).
[211] *Du Pont*, 430 U.S. at 127 n.17. The Supreme Court pointed to 33 U.S.C. § 311(c), which allows modification of BAT limitations for a facility if "such modification requirements (1) will represent the maximum use of technology within the economic capability of the owner or operator; and (2) will result in reasonable further progress toward the elimination of the discharge of pollutants." The Court explained, "This provision shows that the [33 U.S.C. § 1311(b)] limitations for 1983 are to be established prior to consideration of the characteristics of the individual plant. Moreover, it shows that the term 'best technology economically achievable' does not refer to any individual plant. Otherwise, it would be impossible for this 'economically achievable' technology to be beyond the individual owner's 'economic capability.'" *Du Pont*, 430 U.S. at 127 n.17 (internal citation omitted). *See also Texas Oil & Gas Ass'n*, 161 F.3d at 928 ("[I]n promulgating ELGs the EPA must set discharge limits that reflect the amount of pollutant that would be discharged by a point source employing the best available technology that the EPA determines to be economically feasible across the category or subcategory as a whole.");" *Chem. Mfrs. Ass'n*, 870 F.2d at 219 n.157 ("Congress intended that economic impacts be determined only for classes of facilities, rather than on a plant-by-plant basis. 1972 Leg. Hist. at 255, 304.").
[212] Arsenic, mercury, and selenium are toxic pollutants for purposes of setting BAT. See 33 U.S.C. § 1317(a)(1) (requiring EPA to publish list of toxic pollutants); § 1317(a)(2) (requiring EPA to set BAT for listed toxic pollutants); 40 C.F.R. § 401.15 (listing arsenic, mercury, and selenium as toxic pollutants pursuant to 33 U.S.C. § 1317(a)(1)).
[213] *Du Pont*, 430 U.S. at 127 n.17. See also *Nat'l Crushed Stone*, 449 U.S. at 79 ("Congress foresaw and accepted the economic hardship, including the closing of some plants, that effluent limitations would cause; and Congress took certain steps to alleviate this hardship . . . ").
[214] 33 U.S.C. § 1311(c).
[215] Compare id. ("The Administrator may modify the requirements of subsection (b)(2)(A) of this section with respect to any point source for which a permit application is filed after July 1, 1977, upon a showing by the owner or operator of such point source satisfactory to the Administrator that such modified requirements (1) will represent the maximum use of technology within the economic capability of the owner or operator; and (2) will result in reasonable further progress toward the elimination of the discharge of pollutants.") with id. § 1311(l) ("Other than as provided in subsection (n) of this section, the Administrator may not modify any requirement of this section as it applies to any specific pollutant which is on the toxic pollutant list under section 1317(a)(1) of this title.").
[216] Id. § 1314(n)(1)(A). Section 301(g) provides another mechanism to modify ELGs for individual facilities, but 301(g) modifications are likewise barred for toxic pollutants. Id. § 1311(g)(4)(a).

[217] H.R. Rep. No. 99-1004, at 123 (1986) (Conf. Rep.).
[218] 132 Cong. Rec. S16,426 (daily ed. Oct. 16, 1986) (statement of Sen. Stafford) (emphasis added).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 67

Comment Excerpt:

c. EPA has no basis in the CWA for the High Flow Subcategory

EPA has no reasoned basis to reverse its policy, because it has no statutory authority for its current position. As discussed, the Clean Water Act authorizes EPA to promulgate ELGs for categories and classes of point, and other provisions, like the NPDES program or FDF variance, tailor the Act's requirements for individual facilities.[235] Congress made every effort to prohibit EPA from modifying a facility's effluent limitations for toxic pollutants based on an individual facility's compliance costs.[236] A one-facility, cost-based subcategory for toxic pollutants flouts the text, structure, and legislative history of the Clean Water Act. Therefore, EPA has no reasoned basis for its new policy.

5. The proposal is arbitrary and capricious.

Even if EPA acknowledges and explains the many inconsistencies of its policy shift, the proposed subcategory would still be arbitrary and capricious because the agency overestimates costs, gives controlling weight to an irrelevant factor while ignoring mandated factors, ignores reasonable alternatives, and reaches contradictory conclusions.

[235] See Section V(d)(3) – The Act Prohibits EPA's Proposed Subcategory.
[236] See Section V(d)(3)(b) - The Act Prohibits EPA from Creating Single-Facility, Cost-Based BAT Subcategories.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 69

Comment Excerpt:

b. EPA Relies on an Irrelevant Factor and Ignores Statutory Factors

EPA improperly considered the costs of a single facility in setting BAT for the High Flow Subcategory. BAT must be economically achievable, but "Congress intended that economic impacts be determined for classes of facilities, rather than on a plant-by-plant basis."[244] The Act's structure and legislative history show that Congress intended to prohibit EPA from setting effluent limitations for toxic pollutants based on an individual facility's costs.[245] And while industry-wide costs are relevant in setting BAT, they are of secondary importance.[246] Allegedly disproportionate costs for a single facility are not a legitimate factor for setting BAT, which "represents a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges."[247] By justifying BAT for toxic pollutants solely based on Cumberland's relatively high compliance costs, "the agency has relied on factors which Congress has not intended it to consider."[248]

EPA ignored BAT's express statutory factors. To justify a BAT subcategory, a class of facilities must be fundamentally different with respect to the factors listed in 33 U.S.C. § 1314(b)(2)(B).[249] "Although the EPA has significant discretion in deciding how much weight to accord each statutory factor under the CWA, it is not free to ignore any individual factor entirely. Both the CWA, 33 U.S.C. § 1314(b)(2), and the EPA's own regulations, 40 C.F.R. § 125(c)-(d), state that the EPA shall take into account (or apply) certain factors in making a BAT determination . . . ."[250] Those factors include "the engineering aspects of the application of various types of control techniques, process changes, [and] non-water quality environmental impact." 33 U.S.C. § 1314(b)(2)(B).

[244] *Chem. Mfrs. Ass'n*, 870 F.2d at 219 n.157.
[245] See Section V(d)(3) - The Act Prohibits EPA's Proposed Subcategory.
[246] *See Am. Iron and Steel Inst. v. EPA*, 526 F.2d 1027, 1052 n.51 (3d Cir. 1975) ("[I]t is clear that for 'BATEA' standards, cost was to be less important than for the 'BPCTCA' standards, and that for even the 'BPCTCA' standards cost was not to be given primary importance.").
[247] *Nat'l Crushed Stone*, 449 U.S. at 74.
[248] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).
[249] *Citizens Coal Council v. EPA*, 447 F.3d 879, 893 (6th Cir. 2006).
[250] *Texas Oil & Gas Ass'n*, 161 F.3d at 934. See also *Sw. Elec. Power Co.*, 920 F.3d at 1006 ("[T]he Act lists factors the Administrator must consider in determining BAT.").

Commenter Name: Thomas Cmar
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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 141

Comment Excerpt:

c. EPA has no basis in the CWA for the High Flow Subcategory.

EPA has no reasoned basis to reverse its policy, because it has no statutory authority for its current position. As discussed, the Clean Water Act authorizes EPA to promulgate ELGs for categories and classes of point, and other provisions, like the NPDES program or FDF variance, tailor the Act's requirements for individual facilities.[538] Congress made every effort to prohibit EPA from modifying a facility's effluent limitations for toxic pollutants based on an individual facility's compliance costs.[539] A one-facility, cost-based subcategory for toxic pollutants flouts the text, structure, and legislative history of the Clean Water Act. Therefore, EPA has no reasoned basis for its new policy.

4.The proposed High FGD Flow Subcategory is arbitrary and capricious.

Even if EPA acknowledges and explains the many inconsistencies of its policy shift, the proposed subcategory would still be arbitrary and capricious because the agency overestimates costs, gives controlling weight to an irrelevant factor while ignoring mandated factors, ignores reasonable alternatives, and reaches contradictory conclusions.

[538] See Section X.F.2 – The Act Prohibits EPA's Proposed Subcategory.
[539] See Section X.F.2.B - The Act Prohibits EPA from Creating Single-Facility, Cost-Based BAT Subcategories.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 143

Comment Excerpt:

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EPA ignored BAT's express statutory factors. To justify a BAT subcategory, a class of facilities must be fundamentally different with respect to the factors listed in 33 U.S.C. § 1314(b)(2)(B).[552] "Although the EPA has significant discretion in deciding how much weight to accord each statutory factor under the CWA, it is not free to ignore any individual factor entirely. Both the CWA, 33 U.S.C. § 1314(b)(2), and the EPA's own regulations, 40 C.F.R. § 125(c)-(d), state that the EPA *shall* take into account (or apply) certain factors in making a BAT determination . . . ."[553] Those factors include "the engineering aspects of the application of various types of control techniques, process changes, [and] non-water quality environmental impact." 33 U.S.C. § 1314(b)(2)(B).

[547] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 219 n.157.
[548] See Section X.F.2 - The Act Prohibits EPA's Proposed Subcategory.
[549] See Am. Iron and Steel Inst. v. EPA, 526 F.2d 1027, 1052 n.51 (3d Cir. 1975) ("[I]t is clear that for 'BATEA' standards, cost was to be less important than for the 'BPCTCA' standards, and that for even the 'BPCTCA' standards cost was not to be given primary importance.").

[550] *Nat'l Crushed Stone*, 449 U.S. at 74.
[551] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983).
[552] *Citizens Coal Council v. EPA*, 447 F.3d 879, 893 (6th Cir. 2006).
[553] T*exas Oil & Gas Ass'n*, 161 F.3d at 934. See also *Sw. Elec. Power Co*., 920 F.3d at 1006 ("[T]he Act lists factors the Administrator must consider in determining BAT.").

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 184

Comment Excerpt:

XIV. THE ENDANGERED SPECIES ACT REQUIRES EPA TO CONSULT WITH THE FISH AND WILDLIFE SERVICE AND NATIONAL MARINE FISHERIESSERVICE BEFORE FINALIZING THE RULE.

Section 2(c) of the Endangered Species Act ("ESA") establishes that "all Federal departments and agencies shall seek to conserve endangered species and threatened species and shall utilize their authorities in furtherance of the purposes of this Act."[690] The ESA defines "conservation" to mean "the use of all methods and procedures which are necessary to bring any endangered species or threatened species to the point at which the measures provided pursuant to this Act are no longer necessary."[691] As the Supreme Court has unequivocally summarized, the ESA's "language, history, and structure" make clear "beyond a doubt" that "Congress intended endangered species to be afforded the highest of priorities" and endangered species should be given "priority over the 'primary missions' of federal agencies."[692] Simply put, "the plain intent of Congress in enacting this statute was to halt and reverse the trend toward species extinction, *whatever the cost*."[693]

To fulfill the substantive purposes of the ESA, each federal agency is required under Section 7 of the Act to engage in consultation with the U.S. Fish and Wildlife Service ("FWS") and/or the National Marine Fisheries Service ("NMFS" or, collectively, the "Services") to "insure that any action authorized, funded, or carried out by such agency . . . is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species . . . determined . . . to be critical."[694]

EPA's duty to engage in the Section 7 consultation process prior to taking any action that "may affect" a threatened or endangered species or their habitats is firmly established by the unambiguous text of the ESA.[695] Section 7 consultation is required for every *discretionary* agency action that "may affect listed species or critical habitat."[696] Agency "action" is broadly defined in the ESA's implementing regulations to include "(a) actions intended to conserve listed species or their habitat; (b) *the promulgation of regulations*; (c) the granting of licenses, contracts, leases, easements, rights-of-way, permits, or grants-in-aid; or (d) actions directly or indirectly causing modifications to the land, water, or air."[697] The Services' joint regulations further clearly require programmatic consultations on federal, nationwide rulemakings that impact listed species. [698]

Under these unambiguous terms and in light of the facts of the current rulemaking, the ESA requires that EPA consult with the Services and prepare a biological opinion prior to taking action on the 2019 Proposal.

[690] 16 U.S.C. § 1531(c)(1).
[692] *Tenn. Valley Auth. v. Hill*, 437 U.S. 153, 174-75 (1978).
[693] Id. at 184 (emphasis added).
[694] 16 U.S.C. § 1536(a)(2).
[695] See, e.g., *Tenn. Valley Auth.*, 437 U.S. at 188 (In describing the "broad sweep" of the statute's authority, the Court established that "[i]n passing the Endangered Species Act of 1973, Congress was also aware of certain instances in which exceptions to the statute's broad sweep would be necessary. Thus, § 10, [. . .] creates a number of limited 'hardship exemptions,' none of which would even remotely apply to the Tellico Project. In fact, there are no exemptions in the Endangered Species Act for federal agencies, meaning that under the maxim *expressio unius est exclusio alterius*, we must presume that these were the only 'hardship cases' Congress intended to exempt").
[696] See *Nat'l Ass'n of Home Builders v. Defs. of Wildlife*, 551 U.S. 644 (2007); 50 C.F.R. § 402.14(a).
[697] Id. § 402.02 (emphasis added).
[698] See, e.g., Interagency Cooperation – Endangered Species Act of 1973, as Amended; Incidental Take Statements, 80 Fed. Reg. 26,832 (May 11, 2015) (attached).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 188

Comment Excerpt:

B. EPA Retains Considerable Discretion in Setting Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category

The Supreme Court in *National Ass'n of Home Builders v. Defenders of Wildlife* identified a narrow exception to the Section 7 consultation requirement when the federal agency has no statutory discretion to act.[719] That exception does not apply here.

In *Home Builders*, the Court held that Section 402(b) of the CWA does not require ESA consultations because EPA action under Section 402(b) is nondiscretionary: once a state has "met nine specified criteria" under the law, EPA "shall approve" and transfer the NPDES permitting authority to a state.[720] Nevertheless, EPA boldly attempts to stretch the Court's holding here to claim that the 2019 Proposal is non-discretionary.[721]

This rulemaking, however, is not similar to *Home Builders* as a matter of law or of fact. First, as EPA has consistently demonstrated throughout the variety of changes between the 2015 ELG Rule and the 2019 Proposal (as well as through past ELG rulemakings), it possesses substantial discretion to decide what to include in its ELG rulemakings and ultimately what course of action to take.[722] Indeed, EPA itself agrees, arguing within its own preamble that, "[t]he Agency retains *considerable discretion* in assigning the weight to be accorded [to] each of these required consideration factors."[723] And then again that, "[t]he EPA's proposal is based on its discretion to give particular weight to the CWA Section 304(b)."[724] The decision to rollback and weaken standards for ELGs is clearly a discretionary policy decision and not a ministerial or nondiscretionary action where EPA is compelled to act by a clear statutory command.

The D.C. Circuit has consistently held since as early as 1978 that EPA possesses discretion when setting effluent limitation guidelines.[725] In describing this discretion in *Weyerhaeuser Co. v. Costle*, the D.C. Circuit noted that among the "consideration factors" that EPA shall weigh include "non-water quality environmental impact" and "other factors as the Administrator deems appropriate."[726] Similarly in a very recent 2019 case, the D.C. Circuit also held that EPA retained discretion when setting annual biomass-based fuel standards because it must consider six factors, one of which is based "on environmental considerations, such as concerns about wetland conversion, wildlife habitat, and water quality."[727] Here, the situation is comparable. Because EPA possesses significant discretion in setting a standard such as the ELGs, it cannot attempt to merely avoid its obligations under the ESA by labeling the rule non-discretionary without being able to point to any statutory command making it so. The ESA and the endangered and threatened species that rely on its consistent, lawful application demand more.

Beyond the discretion obviously provided to EPA through the four corners of the law, the 2019 Proposal also reeks of discretion in its implementation. For example, in addition to the discretionary act of assigning the relative weights for each consideration factor, EPA developed an optional, voluntary incentives program that extends the deadlines for compliance if facilities implement certain process changes and controls to achieve other pollution reduction targets.[728] The CWA is silent on whether such "voluntary programs" are permissible, let alone mandatory. Nothing in the law states that EPA *shall* establish these types of programs. Yet, EPA's discretionary choice to develop this voluntary program will have real-world impacts on many endangered species because the program extends the period of time that those species will potentially be exposed to toxic pollutants.

EPA must, therefore, comply with the procedural and substantive requirements of the ESA before moving forward with the 2019 Proposal.

[719] *Nat'l Ass'n of Home Builders v. Defs. of Wildlife,* 551 U.S. 644 (2007); 50 C.F.R. § 402.14(a).
[720] Id. at 650.
[721] Email from Richard J. Benware, Team Leader, U.S. EPA-Office of Water Steam Elec. ELG, to Brett Hartl, Gov't Affairs Dir., Ctr. for Biology Diversity (Nov. 27, 2019) ("re: Question regarding ELGs for the Steam Electric Power Generating Point Source Category") ("The EPA has not prepared a Biological Evaluation at this time, and due to the lack of discretion to consider such information, does not currently intend to do so. However, this is only a proposed rule, and to the extent that you have comments on this issue, I encourage you to submit them to the docket within the public comment period so that we may appropriately consider them.") (attached).
[722] Commenters note that the mere fact that an agency possesses discretion does not shield or insulate them when an action is taken in a lawless, arbitrary, or capricious manner.
[723] 2019 Proposal at 64,624 (emphasis added) (citation omitted).
[724] Id. at 64,635 (emphasis added).
[725] *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1045 (D.C. Cir. 1978) ("In contrast, Congress did not mandate any particular structure or weight for the many consideration factors. Rather, it left EPA with discretion to decide how to account for the consideration factors, and how much weight to give each factor.").
[726] Id.
[727] *Am. Fuel & Petrochemical Mfrs. v. EPA*, 937 F.3d 559, 597 (D.C. Cir. 2019).
[728] 84 Fed. Reg. at 64,622.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 189

Comment Excerpt:

C. EPA Must Engage in Formal Section 7 Consultation on the 2019 Proposal Because the Action "May Effect" ESA-Listed Species

Given EPA's considerable discretion in this action, it must lawfully comply with its obligations under the ESA. To comply with the requirements of the ESA, EPA must first make a threshold determination as to whether its actions will either have "no effect" or "may affect" any threatened or endangered species. As discussed by the D.C. Circuit in *American Fuel & Petrochemical Manufacturers*,

As the first step in this process, the agency must make an "effects determination," i.e., the agency must assess whether a proposed action "may affect" listed species or critical habitat. 50 C.F.R. § 402.14(a). If so, the agency must engage in formal consultation with the Services. But if the agency makes a "no effect" determination by finding that its proposed action "will not affect any listed species or critical habitat," then "it is not required to consult" with the Services.[729]

Additional cases reinforce the simple proposition that a regulation that may affect endangered species must be the subject of consultation.[730] And indeed, in this instance the analysis as to whether this action "may effect" species, and therefore require EPA to consult with the Services and prepare a Biological Opinion,[731] is a simple one because the 2019 Proposal already concedes that the changes here will certainly result in adverse effects on endangered species and their critical habitats, as discussed more specifically below.

During the formal consultation process, the Services assess the environmental baseline, which is defined as "the past and present impacts of all Federal, State, or private actions and other human activities in an action area, the anticipated impacts of all proposed Federal projects in an action area that have already undergone formal or early [S]ection 7 consultation, and the impact of State or private actions that are contemporaneous with the consultation in process."[732] In addition, the Services assess the cumulative effects to the species – which are defined as "those effects of future State or private activities, not involving Federal activities, that are reasonably certain to occur within the action area of the Federal action subject to consultation" – and determine if the agency action jeopardizes the continued existence of each species impacted by the agency action.[733] As Commenters note here, the proper legal baseline is the 2015 ELG Rule, despite EPA's attempts in the preamble to confuse the issue and manipulate the baseline in its favor.

[729] *Am. Fuel & Petrochemical Mfrs*., 937 F.3d at 597.
[730] See, e.g., *W. Watersheds Project v. Kraayenbrink*, 632 F.3d 472, 495 (9th Cir. 2011); *Nat'l Parks Conservation Ass'n v. Jewell*, 62 F. Supp. 3d 7 (D.D.C. 2014); *Citizens for Better Forestry v. USDA*,

481 F. Supp. 2d 1059 (N.D. Cal. 2007); *Wash. Toxics Coal. v. U.S. Dep't of Interior*, 457 F. Supp. 2d 1158 (W.D. Wash. 2006).

[731] Under the joint regulations implementing the ESA, if an impact on a listed species is predicted to occur, then EPA must complete consultations with the Services. If EPA elects to first complete an informal consultation, it must first determine whether its action is "not likely to adversely affect" (NLAA) a listed species or is "likely to adversely affect" (LAA) a listed species. The Services define "NLAA" determination to encompass those situations where effects on listed species are expected to be "discountable, insignificant, or completely beneficial." Discountable effects are very rare, and limited to situations where it is not possible to "meaningfully measure, detect, or evaluate" harmful impacts. Any harm or take of an individual member of a listed species crosses the LAA threshold and requires formal consultations with the Services. For additional information, see U.S. Fish & Wildlife Serv. & Nat'l Marine Fisheries Serv., Endangered Species Consultation Handbook: Procedures for Conducting Consultation and Conference Activities Under Section 7 of the Endangered Species Act (1998), https://www.fws.gov/endangered/esa-library/pdf/esa_section7_handbook.pdf (attached).

[732] Id. at E-10.

[733] Id. at xiii.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 192

Comment Excerpt:

D. Section 7(d) of the ESA Prohibits a Federal Agency from Making Any Irreversible or Irretrievable Commitments of Resources Prior to Completing the Section 7 Consultation Process

In addition to EPA's specific Section 7 consultation obligations, Section 7(d) of the ESA prohibits a federal agency from "[making] any irreversible or irretrievable commitment of resources with respect to the agency action which has the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures . . . ."[745] By failing to consult with the Services, EPA will be taking action that will push more endangered species toward extinction while denying the possibility that a reasonable and prudent measure could ever be implemented to protect a listed species or its critical habitat. Accordingly, EPA would be in violation of Section 7(d) of the ESA should it finalize the 2019 Proposal without first consulting with the Services.

In sum: in recent years, Commenters have experienced numerous instances in which EPA appears to deliberately misconstrue the purpose of ESA consultations in an attempt to avoid those obligations. By skirting the procedural requirements of the ESA, EPA exacerbates the substantive violations of the law's command not to jeopardize the existence of any endangered or threatened species.[746] The procedural and substantive goals of the ESA consultation process do not compel EPA – or any agency for that matter – to take only those actions that are the most beneficial imaginable for listed species.

With respect to this rulemaking, the ESA does not compel EPA to only set ELGs that are the best for endangered species. Instead, it requires that EPA consider and analyze the impacts on listed species in consultation with the Services and, through that analysis, determine whether its choices and actions might cause harm to listed species. If the consultation process finds that the 2019 Proposal jeopardizes a particular threatened or endangered species, EPA still retains discretion on how to proceed, but it must do so after participating in formal consultation and will need to implement reasonable and prudent alternatives, as recommended by the Services, or other equally protective conservation measures. If it does not, its actions here will doom countless species to preventable and unlawful further imperilment and jeopardy under the ESA.

[745] 16 U.S.C. § 1536(d).
[746] *Thomas v. Peterson*, 753 F. 2d 754, 765 (9th Cir. 1985) ("If anything, the strict substantive provisions of the ESA justify *more* stringent enforcement of its procedural requirements, because the procedural requirements are designed to ensure compliance with the substantive provisions. The ESA's procedural requirements call for a systematic determination of the effects of a federal project on endangered species. If a project is allowed to proceed without substantial compliance with those procedural requirements, there can be no assurance that a violation of the ESA's substantive provisions will not result.").

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 205

Comment Excerpt:

XVIII.EPA FAILED TO ENSURE ADEQUATE PUBLIC PARTICIPATION.

A. Both the Clean Water Act and the Administrative Procedure Act Require Meaningful Public Participation.

EPA must provide meaningful time and opportunity to comment on proposed rules. The Administrative Procedure Act directs that agencies undertaking rulemaking allow "interested persons an opportunity to participate," and empowers courts to invalidate agency decisions, including those concerning the public comment opportunity, if such choices are arbitrary" or "capricious," or the agency commits "an abuse of discretion" in establishing the comment opportunity.[793] The Clean Water Act similarly provides that "[p]ublic participation in the development, revision, and enforcement of any regulation, standard, effluent limitation, plan, or program established by the Administrator or any State under this Act shall be provided for, encouraged, and assisted by the Administrator and the States."[794] And the presumptive minimum comment period for run-of-the-mill rulemakings pursuant to Executive Order 12,866 is sixty days.[795]

B. EPA Refused To Provide In-Person Public Hearings.

EPA did not provide members of the public an opportunity to appear in person to testify before the agency and share concerns about the proposal. Instead, the agency held a "virtual" public hearing on December 19, during which participants were limited to brief, three-minute remarks. Furthermore, EPA discouraged public input during the hearing on the bulk of the proposal, as the agency sought to limit the subject matter of the hearing to the proposed changes to the pretreatment standards only.[796]

EPA denied the public a requested in-person public hearing. EPA apparently concluded that an online input session is a meaningful opportunity for comment, but that is mistaken. As eighty-seven groups that joined to request an in-person hearing stressed:

A genuine public hearing serves many critical functions. It offers any member of the public the opportunity to speak directly to agency representatives, who are physically present in the room. It provides the public with opportunities to bring visual aids, such as maps, photos, contaminated water and soil, etc. The speaker also has the opportunity to have family members or other representatives from the impacted community present as support. The agency, in turn, has the immeasurable and irreplaceable benefit of seeing the speakers and hearing their testimonies directly, which may be filled with emotion and urgency that cannot be conveyed in a phone call. Members of government agencies, elected officials, the press, and the general public similarly have the opportunity to gain such knowledge during a genuine public hearing. A call session is not an appropriate or legal substitute for in-person public hearings.[797]

Consequently, EPA's refusal to hold an in-person public hearing on the full range of issues deprived people concerned about this rulemaking all of these important values.

EPA's longstanding interpretation is that a public hearing is an in-person event. EPA's public participation regulations applicable to Clean Water Act rulemakings commit the Agency to "provide for, encourage, and assist the participation of the public,"[798] and "to foster a spirit of openness and mutual trust among EPA . . . and the public" and "use all feasible means to create opportunities for public participation, and to stimulate and support participation."[799]

Furthermore, EPA defines "public participation" as "providing ample opportunity for interested and affected parties to communicate their views" and "providing access to the decision-making process, seeking input from and conducting dialogue with the public."[800] As noted by the former EPA official responsible for promulgating the Agency's public participation regulations: "Part 25 Public Participation regulation expected hearings to be in-person hearings and that was the common understanding at EPA."[801]

EPA guidance documents reinforce the point that additional means of encouraging public input should only supplement, but not replace, in-person hearings, which are the bedrock of public participation. When EPA updated its program-wide Public Involvement Policy in 2003 to "reflect[] . . . new options for public involvement through the internet," it stated that the new Policy "is meant to encourage development of new tools for public involvement and should not limit the degree or types of public involvement already in use at EPA."[802] Similarly, the policy says, "[w]henever feasible, Agency officials should strive to provide increased opportunities for public involvement above and beyond the minimum regulatory requirements."[803]

Underscoring the fact that online engagement should supplement, but not replace, in-person hearings is a report prepared for EPA regarding a two-week, interactive, online dialogue it conducted "to complement the formal notice-and-comment process" for input on the draft 2003 Public Involvement Policy.[804] While highlighting the potential benefits of using online tools to reach "a much larger and diverse population," the report found that such tools should not replace traditional in-person events.

Broad support for future use of on-line dialogues at EPA came with an important condition: that they be used only in conjunction with traditional approaches to participation. According to respondents, too many people lack computer access for EPA to replace traditional public participation with on-line dialogues. Some respondents also said that the dynamics of on-line interaction were simply not as rich and productive as face-to-face participation.[805]

EPA's National Environmental Justice Advisory Council ("NEJAC") makes this same point. "Social media and technology . . . should not take the place of face-to-face engagement with community members."[806] Indeed, limiting public participation opportunities to those with internet access has serious environmental justice impacts. Approximately 10% of American adults lack internet access, with a disproportionate share of that population being black, Hispanic, and/or low-income.[807]

Long-time EPA personnel who were directly involved in the Agency's public participation efforts have made it clear that hearing directly, in-person, from affected citizens is a crucial part of the decision-making process. The following two statements have been provided by former EPA staffers to the docket of the related CCR "Part A" proposal:

I served as a hearing panelist and auditor for many EPA public hearings, and assure you that it makes a difference to actually see and interact with members of the public who give hearing testimony. It is not just the opportunity to see witnesses and assess body language. Having a live presence can promote dialogue, and encourage questioning that elicits useful information. This is much harder to do when contact is a disembodied voice. It is also moving for EPA panelists to see ordinary citizens coming to testify, many taking time off from jobs to do so. . . . There is also the important gain in perspective from getting out of headquarters to see people in the rest of the country. This perspective is lost in the virtual context, when EPA personnel participate from headquarters.[808]

The agency would receive better information as part of this rulemaking process if it were to include face-to-face communications as part of its process to receive feedback on the proposed regulations from the public.[809]

EPA's current failure to provide an in-person opportunity to weigh in on changes to the effluent limitations applicable to power plants contrasts with the agency's approach in developing the requirements that EPA now proposes to change. In 2013, during the public comment period on the proposed rules, EPA held an in-person hearing in Washington, DC.[810]

The agency's actions denying a meaningful public hearing on the proposal thus contravenes the Clean Water Act's instruction to EPA to facilitate public participation in its rulemakings. Moreover, EPA's failure to explain its deviation from the robust policy of public dialogue reflected in its preexisting regulations, policy guidance, and the observations of former agency staff is arbitrary and capricious.

[793] 5 U.S.C. §§ 553(c), 706(2)(A); see also *Fund for Animals, Inc. v. Rice*, 85 F.3d 535, 545 (11th Cir. 1996) (evaluating agency's refusal to hold public hearing to determine if action was arbitrary or capricious or abuse of discretion).
[794] Clean Water Act § 101(e); 33 U.S.C. § 1251(e).
[795] E.O. 12,866, 58 Fed. Reg. 51,735, § 6(a)(1) (Sept. 30, 1993) ("[E]ach agency should afford the public a meaningful opportunity to comment on any proposed regulation, which in most cases should include a comment period of not less than 60 days.").
[796] EPA, Steam Electric Power Generating Effluent Guidelines – 2019 Proposed Revisions: Public Hearing, https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2019-proposed-revisions#public-hearing (visited Dec. 18, 2019) ("The EPA will conduct a public hearing on the proposed pretreatment standards on Thursday, December 19, 2019, at 1:00 PM EST. The hearing will be conducted online only.").
[797] Letter from L. Evans & T. Cmar, Earthjustice et al., to P. Wright & D. Ross, EPA, Re: Request for Public Hearings and 120-Day Comment Periods for Proposed Rules regarding Coal Combustion Residuals Closure Deadlines (Part A) and Revision of Steam Electric Power Generating Effluent Limitations Guidelines, Docket ID No. EPA-HQ-OW-2019-0172-0025 (Dec. 4, 2019).
[798] 40 C.F.R. § 25.3(a).
[799] Id. § 25.3(c).
[800] Id. § 25.3(b).
[801] Lee Daneker, Comment Letter submitted to Docket No. EPA-HQ-OLEM-2019-0172-0027 (Jan. 7, 2020) (attached). EPA has not amended its Public Participation Regulations, 40 C.F.R. Part 25, since promulgating them under Mr. Daneker's stewardship in 1979.
[802] 68 Fed. Reg. 33,946, 33,946-47 (June 6, 2003). See also EPA, Public Involvement Policy and Related Documents, https://archive.epa.gov/publicinvolvement/web/html/index-6.html.
[803] Id.
[804] 68 Fed. Reg. 33,946 (June 6, 2003). See also Thomas C. Beierle, RFF Report, Democracy On-Line: An Evaluation of the National Dialogue on Public Involvement in EPA Decisions (Jan. 2002) at 8, https://archive.epa.gov/publicinvolvement/web/html/index-6.html (attached).
[805] Thomas C. Beierle, RFF Report, Democracy On-Line: An Evaluation of the National Dialogue on Public Involvement in EPA Decisions (Jan. 2002) at 32, https://archive.epa.gov/publicinvolvement/web/html/index-6.html (attached).
[806] NEJAC, Model Guidelines for Public Participation: An Update to the 1996 NEJAC Model Plan for Public Participation (Jan. 25, 2013) at 5, https://www.epa.gov/environmentaljustice/model-guidelines-public-participation (attached).
[807] Monica Anderson et al., 10% of American's don't use the internet. Who are they? Pew Research Center (Apr. 22, 2019), https://www.pewresearch.org/fact-tank/2019/04/22/some-americans-dont-use-the-internet-who-are-they/ (attached).
[808] Steven Silverman, Comment Letter submitted to Docket No. EPA-HQ-OLEM-2019-0172-0026 (Jan. 6, 2020) (attached).
[809] Lee Daneker, Comment Letter submitted to Docket No. EPA-HQ-OLEM-2019-0172-0027 (Jan. 7, 2020) (attached).
[810] 78 Fed. Reg. 34,432 (June 7, 2013).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 206

Comment Excerpt:

C. A Sixty-Day Public Comment Period, Including Several Holidays, Was Manifestly Inadequate for This Rulemaking.

EPA established January 21 as the end of the public comment period, which began on November 22. Four federal holidays were observed during this period – Thanksgiving Day, Christmas Day, New Year's Day, and Martin Luther King, Jr.'s Birthday. People interested in this rulemaking also celebrated Hanukkah and Kwanzaa during this time and many of these holidays commonly involve extended family vacations and days away from work. Practically speaking, the comment period EPA has afforded to the public is substantially shorter than sixty days.

The docket for this proposed rule contains 1146 entries of supporting materials that were added on November 22, the date the proposal was published in the Federal Register. Many of these materials are highly technical in nature,[811] others are unavailable online because they contain copyrighted information,[812] and others are unavailable altogether because they have been deemed to contain confidential business information.[813] Additional materials were added after the proposal was published.[814] Adequately analyzing the available material and determining how it bears on application of the Clean Water Act to the power plant sector will be practically impossible in the short time EPA has permitted the public to comment.

The regulations that EPA seeks to amend were finalized following a robust public comment period. Specifically, "EPA published the proposed rule on June 7, 2013, and took public comments until September 20, 2013,"[815] a total of 112 days. In keeping with that approach, nearly ninety organizations asked EPA to establish a 120-day comment period for the proposed revisions. However, EPA denied that request.

EPA's constrained opportunity for public comment contradicted the Clean Water Act's instruction to facilitate such participation. EPA also violated the Administrative Procedure Act. Because EPA established a period that, considering holidays, was effectively much shorter than sixty days, because it did not consider the time that would be necessary for commenters to adequately analyze new record materials, and because this rulemaking involves detailed technical and economic information, the agency utterly failed to consider a critical aspect of the issue in determining the comment period. As such, the chosen period was arbitrary and capricious.[816]

[811] See, e.g., PacifiCorp, 2017 Integrated Resource Plan: Volume I, Docket ID No. EPA-HQ-OW-2009-0819-7243 (Apr. 4, 2017).
[812] See, e.g., A. Lewis and D. Mayfield, EPRI, Ecological Effects of Coal Combustion Products – A Literature Review – DCN SE08171, Docket ID No. EPA-HQ-OW-2009-0819-8228 (Dec. 1, 2011).
[813] See, e.g., EPRI, Thermal Evaporation Technologies for Treating Power Plant Wastewater: A Review of Six Technologies, Docket ID No. EPA-HQ-OW-2009-0819-7370 (Sept. 1, 2017).
[814] See, e.g., Email from N. Dernick, NiSource, Inc. to R. Benware, EPA, Re: NIPSCO Follow-Up from ELG Submission Meeting, Docket ID No. EPA-HQ-OW-2009-0819-8275 (June 8, 2018) (posted to docket Dec. 3, 2019).
[815] 80 Fed. Reg. at 67,844.
[816] *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 US 29, 43 (1983) (agency rule is arbitrary and capricious if, among other things, "the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise").

2 Scope and Applicability

No comment excerpts were received on this topic.

3 Regulatory Options - General

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 1

Comment Excerpt:

I. The proposed rule provides appropriate clarification and flexibility for industry.

EPA's proposal properly acknowledges uncertainty in the modeled results associated with impacts that will result from implementing the proposed amendments.[1] EPA further acknowledges that actual compliance costs could be higher than estimated for the four different regulatory options it analyzed. For that reason, EPA should select options in the final rule that allow permitting authorities the flexibility to determine final compliance actions and deadlines.

1 84 Fed. Reg. 64,620, 64,622.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 121

Comment Excerpt:

D. EPA's Economic Impact Analysis Should Account for the Costs of Complying with BATW and FGD Wastewater Limits Established for Plants that Installed or Planned to Install Technologies Because of the 2015 ELG Rule.

In addition to removing retiring and repowering units from the universe of units for which costs were assigned, for each unit that remained in the database, EPA reviewed the changes in the unit's present or planned technology for BATW and FGD wastewater. According to EPA's Supplemental TDD, in order to calculate the *incremental* costs of the regulatory options and their economic impacts, EPA updated the industry profile to reflect BATW and FGD wastewater retrofits put in place after the 2015 rule or planned for installation by December 31, 2028. Supplemental TDD, Section 5; ERG, 2019 Industry Change Memo at 6-7. In other words, to the extent the facility already had in place (or planned to have in place by the end of 2028) a technology that would satisfy the proposed regulatory option, EPA did not count that cost, or the economic impact of that cost, as a cost of the Proposed Rule. Although the ERG analysis correctly notes the deadlines EPA has proposed for complying with its preferred option, except for the VIP option, those deadlines are three to five years *before* the end of 2028. ERG, 2019 Industry Change Memo at 2 n.2. Neither the Supplemental TDD nor the ERG memorandum discusses the implications of this disconnect.

Thus, the costs and economic impacts of the regulatory options EPA evaluated apparently did not include the costs of any technology the units in question had installed, or indicated they were prepared to install, since 2015, *even if those technology changes were driven in whole or in part by the 2015 ELG rule and even though some or all of those costs will be incurred after EPA finishes this rulemaking.* This is problematic, given that one of the grounds for reconsideration was to examine whether EPA had underestimated the costs (or overestimated the performance) of the technologies on which EPA based the 2015 rule. See UWAG, Petition for Reconsideration of EPA's Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-HQ-OW-2009-0819-6478 (Mar. 24, 2017); EPA, Letter to Petitioners in Response to the Petitions for Agency Reconsideration and Stay of Effluent Guidelines for the Steam Electric Point Source Category, EPA-HQ-OW-2009-0819- 6483 (Apr. 12, 2017).

Adjusting the industry profile in this fashion underestimates the costs and economic impacts of the rule. For example, if a company already has committed to installing chemical precipitation with some form of biological treatment and EPA has now changed the mercury limits to require performance that only ultrafiltration (a far more expensive technology than sand filters) can provide, EPA's approach will not take into account the total cost of both the system the facility planned to install and the additional technology the Proposed Rule will require. As a result, EPA will underestimate the impact of the technology-based limits on that facility.

EPA should consider the total cost and economic impacts of all technologies that will be required by any final rule, taking into account the actual applicability dates by which technologies must be in place.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 13

Comment Excerpt:

B. EPA Fails To Compare Regulatory Options To The Correct Baseline

EPA's baseline – the 2015 ELG Rule – makes sense from a narrow legal perspective, in the sense that one may want to evaluate how the 2019 Proposal will affect existing legal obligations. However, very few plants have installed the pollution controls on bottom ash transport water and FGD wastewater required by the 2015 rule. As a result, for all practical purposes, the rule has not yet been implemented for these wastestreams.[64] If one wants to know how the 2019 Proposal will change costs and pollution loads going forward, the appropriate baseline is current conditions. And indeed, EPA used a current conditions baseline for some purposes, for example in justifying a low-utilization subcategory.[65]

Yet EPA arbitrarily fails to compare its regulatory options to current conditions in most of its analyses. As a result, the Agency fails to provide useful information about the extent to which each regulatory option will affect compliance costs and environmental outcomes relative to the existing state of the industry. This is arbitrary and capricious.

[64] Very few units have installed the FGD treatment systems required by the 2015 Rule. According to the ERG "current discharges" memorandum, of the seventy-one plants with an FGD treatments system, thirty are simply using ponds (no further treatment), another thirty-one are using chemical precipitation, and only nine are using chemical precipitation and biological treatment (or something more advanced). ERG, Pollutant Loadings Associated with Current Discharges of FGD Wastewater and Bottom Ash Transport Water – DCN SE07214, Docket ID No. EPA-HQ-OW-2009-0819-7836 (July 15, 2019). For bottom ash, where the 2015 Rule would require zero discharge for virtually all units, only 38% of plants are currently achieving zero discharge. Id.

[65] See, e.g., 84 Fed. Reg. at 64,638 ("Figure VIII-1 below presents costs per MWh produced as measured against the status quo, rather than against the 2015 rule baseline.").

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 4

Comment Excerpt:

Berkshire Hathaway Energy supports the proposed changes to the bottom ash (BA) transport water and flue gas desulfurization (FGD) wastewater limitations. Specifically, Berkshire Hathaway Energy supports the rule modifications that allow for flexibility as it relates to discharge of BA transport water and FGD wastewater. The inclusion of a categorical prohibition on the discharge of BA transport water in the 2015 final rule was unexpected since EPA's four preferred options in the proposed 2015 rule identified impoundments as the technology basis for BAT, except for units with generating capacity larger than 400 MW. The 2019 proposal properly addresses the unexpected confusion and complications presented by the 2015 rule's handling of BA transport water and FGD wastewater, and provides an appropriate compliance path for handling both waste streams using cost-effective methods.

EPA should also maximize flexibility for permitting authorities and regulated facilities in developing limits for BA system purge water in order to address differences in climates and site-specific BA handling configurations.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)

Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 71

Comment Excerpt:

H.1.3.4 Pollutant reduction comparison of the current industry practices and Option 2.

EPRI's analysis confirms that Option 2 is highly effective at reducing BATW TWPEs. EPA's proposed Option 2 includes dry handling or high recycle rates for most units, surface impoundments for units retiring by 2028 and surface impoundments and BMP for low utilization units.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 1

Comment Excerpt:

Oglethorpe Power is generally supportive of EPA's Proposed Rule to revise the current effluent discharge limitations for FGD wastewater and BA transport water under the 2015 ELG rules. As a general matter, EPA has set overly stringent discharge limitations for metals and other wastewater constituents that cannot be reliably achieved by the "best available" control technologies selected by EPA itself in the ELG rulemaking. To correct this problem, the Corporation supports EPA's proposal to establish new source subcategories for EGU boilers that have low-utilization levels or will retire by December 31, 2028. The adoption of these proposed new source subcategories is necessary to avoid the imposition of excessive compliance costs and address unique operating conditions of affected EGU sources.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 1

Comment Excerpt:

CCIG appreciates EPA considering the real-world impacts of the 2015 ELG Rule and addressing those impacts in the Proposed Rule. The Group supports the Proposed Rule's numeric effluent limitations on BAT for FGD wastewater and BATW, as well as the proposed new retirement subcategory.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 6

Comment Excerpt:

With regard to FGD wastewater limits, the proposal for PSES is identical to that for BAT (with the exception of a shorter compliance period for PSES). These limits are based on the selected technology of Chemical Precipitation plus Low-Hydraulic Residence Time Biological Treatment (LRTR). In addition, USEPA's reconsideration analysis resulted in the adjustment of certain numeric effluent limits (increasing some and decreasing others) for arsenic, mercury, selenium and nitrate-nitrite as N. CWLP is generally supportive of these changes, though as explained below, they are unnecessary and inappropriate as applied to Dallman Unit 4 given the fundamentally different factors in its process and pretreatment from those considered by USEPA in developing the rule.

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 1

Comment Excerpt:

On November 22, 2019, the U.S. Environmental Protection Agency ("EPA" or "the Agency") proposed revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 40 C.F.R. Pait 423. [1] The proposals include important changes to determinations of "best available technology economically achievable" ("BAT") promulgated in a 2015 rule. [2] These changes will address fundamental deficiencies in the 2015 rule and provide much-needed relief to regulated entities and permitting authorities facing large capital costs based on umealistic, infeasible, and hasty standards. Cleco Corporate Holdings LLC ("Cleco") therefore suppo1ts the general tlu·ust of the proposed revisions. Cleco also recommends improvements to the revisions to better aclmowledge real-world operating conditions and disproportionate costs of compliance.

[1] See generally Effiuent Limitations Guidelines and Standards for th;. Stearn Electric Power Generating Point Source Category, 84 Fed. Reg. 64,620 (proposed Nov. 22, 2019) [hereinafter· "Proposed Rule"].
[2] See generally Effiuent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,837 (Nov. 3, 2015) [hereinafter "2015 Rule"].

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power

Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 1

Comment Excerpt:

Importance of the Coal Fleet

There are compelling reasons to preserve coal-fired generation. The coal fleet provides fuel security, supports grid reliability and resilience, produces affordable electricity, contributes to fuel diversity, provides electricity when other fuels are not available or are too expensive, and promotes national security.

The importance of the coal fleet has been recognized by the Department of Energy (DOE), Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and grid operators, to name just a few. These entities have recognized the essential attributes the coal fleet provides to the electric grid and have expressed concerns about the impact of the changing electricity mix on grid reliability and resilience.[3]

Unfortunately, U.S. power plant owners have announced the retirement or conversion to other fuels of a staggering number of coal-fired electric generating units (EGUs) since 2010.[4] Almost 700 coal-fired EGUs in 43 states—totaling 133,200 megawatts (MW) of generating capacity—have retired or announced plans to retire. These retirements now exceed 42 percent of the coal fleet that was operating in 2010.

It is likely that this disturbing trend in premature retirements would be exacerbated if EPA were simply to implement the current overly stringent effluent discharge limitations for FGD wastewater and BA transport water. These limitations not only impose excessive compliance costs that are unnecessary to assure protection of human health and the environment, but also may not be technically achievable for some wastewater constituents based on available control technologies. Section 301(b) of the Clean Water Act expressly requires EPA to evaluate the economic impact of proposed ELGs on the affected industry as a whole. As EPA has acknowledged, the 2015 rule would lead to premature coal retirements. Therefore, it is imperative that EPA finalize the proposed changes and take additional steps, described below, to ensure the ELG control requirements do not cause more coal retirements.

3 See e.g., Perry, Rick, "Secretary of Energy's Direction …," Received by Neil Chatterjee, Cheryl LaFleur, and Robert Powelson, September 28, 2017; Federal Energy Regulatory Commission, Department of Energy, "Grid Resiliency Pricing Rule," Notice of Proposed Rulemaking, 82 Fed. Reg. 46940 (October 10, 2017); NERC, "Comments of the North American Electric Reliability Corporation in Response to Notice of Proposed Rulemaking," October 23, 2017; NERC, 2017 Long Term Reliability Assessment.
4 In 2010, according to EIA, the U.S. coal fleet was comprised of 1,396 electric generating units located at 580 power plants for a total electric generating capacity of approximately 317,000 MW.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 1

Comment Excerpt:

TVA supports EPA's proposed effluent limitations guidelines (ELGs) that allow for the discharge of a portion of bottom ash transport water (BA TW) as well as the raising of selenium limits. As the record that EPA has built indicates, the 2015 ELGs were not achievable for many facilities.

Commenter Name: Eric C. Massey
Commenter Affiliation: Arizona Public Service Company
Document Control Number: EPA-HQ-OW-2009-0819-8324-A1
Comment Excerpt Number: 1

Comment Excerpt:

APS strongly supports EPA's proposal to allow a small portion of recirculated bottom-ash transport water ("BATW") to be blown-down or purged in order to ensure the integrity of plant water recycling systems, instead of the 2015's inflexible, zero-liquid discharge requirements.[2] Rather than risk the continued build-up of corrosive constituents, process upsets from unanticipated and severe rainfall events, and failures related to proper water balance—all of which pose serious risks to EGU reliability—EPA's proposal allows for the proper management of these and other conditions by authorizing BATW recirculation system blowdown—i.e., 10% of the total recirculation system volume on a 30-day rolling average. In the absence of this authorization, APS would have faced serious challenges meeting the 2015 ELG's strict ZLD requirements for BATW management, all for very little environmental benefit while creating substantial risks to power plant reliability.

[2] See, 84 Fed. Reg. at 64,675 (November 22, 2019) (proposing a new § 423.13(k)(2)(i)(A) & (B))

Commenter Name: Usha-Maria Turner
Commenter Affiliation: Oklahoma Gas and Electric Company (OG&E)
Document Control Number: EPA-HQ-OW-2009-0819-8290-A1
Comment Excerpt Number: 1

Comment Excerpt:

OG&E strongly supports EPA's proposed revision to the BATW ELG, particularly the important addition of the ten percent discharge allowance. This allowance is both necessary and manageable in an environmentally protective fashion.

As a member of the electric power community and the operator of high recycle rate, closedloop systems, OG&E strongly supports this revision to the BA TW limitations and appreciates EPA's consideration of real-world operating constraints.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 6

Comment Excerpt:

- Limits placed on BATW purge. EPA's Proposed Rule provides that when BATW is reused in the FGD scrubber, the quantity of pollutants in the BATW may not exceed the quantity determined by multiplying the flow of BATW and the concentrations listed in Table 1 to 40 C.F.R. § 423.13(g)(1)(i).[16] EPA should clarify – in preamble, in response to comments, or in the rule provision itself – that BATW purge sent to the FGD scrubber is not subject to BATW limits prior to commingling with other water. Any wastewater discharge from the FGD system would be subject to the FGD wastewater limits, eliminating the need to place BATW limits prior to the scrubber. Further, such clarification would encourage reuse of BATW purge water.

[16] 40 C.F.R. § 423.13(k)(1)(i); Proposed Rule, 84 Fed. Reg. at 64,674.

Commenter Name: Michael P. Alaimo
Commenter Affiliation: Clean Fuels Michigan, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8305-A1
Comment Excerpt Number: 2

Comment Excerpt:

Instead, the agency should reaffirm the zero discharge requirements for coal ash wastewater and strengthen limits for scrubber sludge discharges to control bromide and other pollutants.

Commenter Name: Michael P. Alaimo
Commenter Affiliation: Clean Fuels Michigan, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8305-A1
Comment Excerpt Number: 8

Comment Excerpt:

In conclusion, the record before EPA plainly demonstrates that technologies to eliminate bottom ash wastewater discharges and technologies to limit heavy metals, selenium, nutrients, and bromide in FGD wastewater discharges are available, achievable, and affordable. Requiring power plants to use these proven technologies would prevent more than a billion pounds of pollutants from entering U.S. waters every year, and provide hundreds of millions of dollars per year in public health and environmental benefits. In Michigan, home to 21 percent of the worlds fresh water, the necessity of these standards is particularly salient. Our organizations urge EPA to abandon its plan to gut the strong 2015 standards and instead act swiftly to strengthen them.

Commenter Name: Josh Shapiro, Brian E. Frosh, Kwame Raoul, Dana Nessel, and Thomas J. Donovan, Jr.
Commenter Affiliation: Attorneys General of Maryland, Pennsylvania, Illinois, Michigan, and Vermont
Document Control Number: EPA-HQ-OW-2009-0819-8323-A1
Comment Excerpt Number: 1

Comment Excerpt:

we oppose any effort to weaken, roll back, or improperly extend the deadlines for compliance with either the closure requirements applicable to coal ash impoundments or the effluent limitation guidelines applicable to power plants that generate coal ash and related pollutants. We therefore urge the Environmental Protection Agency ("EPA") to retreat from those aspects of the Coal Ash and ELG Proposals that would ease existing requirements or provide unwarranted extensions of the compliance deadlines.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 4

Comment Excerpt:

EPA's proposals will significantly dilute the protectiveness of the agency's
Clean Water Act regulations with respect to steam electric power generating point sources.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 2

Comment Excerpt:

EPA's 2019 Proposal[1] was born directly from industry requests and has no justification beyond cost savings for the electric utility industry. If finalized as proposed, EPA's revisions would gut long-overdue protections established in the 2015 update to the Clean Water Act Effluent Limitations Guidelines for Steam Electric Power Plants (the "2015 ELG Rule").[2] Among other things, that rule prohibited power plants from dumping fly ash or bottom ash wastewater into U.S. waters and imposed stringent limits on toxic metals and other pollutants in scrubber sludge discharges (known as "Flue Gas Desulfurization" or "FGD" wastewater). Weakening these standards is unjustified and will result in more toxic water pollution that harms human health and the environment. We therefore urge EPA to abandon its misguided and unlawful 2019 Proposal to weaken the 2015 ELG Rule. Instead, for the legal and technical reasons set forth in detail below, EPA must reaffirm the zero discharge requirement for bottom ash transport water and also prohibit the discharge of FGD wastewater.

The record before EPA plainly demonstrates that technologies to eliminate both bottom ash transport water and FGD wastewater are available, achievable, and affordable. Requiring power plants to use these proven technologies would prevent more than a billion pounds of pollutants from entering U.S. waters every year, and provide hundreds of millions of dollars per year in public health and environmental benefits. In light of the clear technical record before EPA, the Clean Water Act requires EPA to eliminate these wastestreams. Our organizations urge EPA to abandon the 2019 Proposal to gut the 2015 ELG Rule and instead act swiftly to strengthen it.

[1] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 84 Fed. Reg. 64,620 (Nov. 22, 2019) ("2019 Proposal").
[2] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,837 (Nov. 3, 2015) ("2015 ELG Rule").

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 1

Comment Excerpt:

We write to express our strong opposition to EPA's proposal to weaken the effluent limitations guidelines and standards for the steam electric point source category under the Clean Water Act (the "2015 Rule"). We agree with and have joined in separate comments by Earthjustice, Clean Water Action, Sierra Club and others explaining our significant concerns over the proposed rule. Our purpose here is not to reiterate those comments, which we adopt and incorporate by reference, but instead to highlight the real-world consequences of EPA's proposals. Our focus is on the Southeast, a region that continues to shoulder a disproportionate pollution burden from coal-based electricity generation. The 2015 Rule appropriately forces coal-burning utilities to lessen that burden. Accordingly, we join in urging EPA to change course and instead strengthen the 2015 Rule with effluent limitations that would further reduce pollution of our lakes, rivers, and streams.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 4

Comment Excerpt:

In the prior Administration, EPA played a role in this progress through its Clean Water Act prosecution of Duke Energy after the Dan River spill in North Carolina, the adoption of the 2015 ELG and CCR Rules, and otherwise. But in this Administration, EPA has contributed nothing to this region-wide pollution cleanup, and in fact has taken action through its regulatory rollbacks to slow progress. As the public has demanded more protection, legislatures across the country have responded while EPA has stepped back. Coal ash legislation has been enacted by Virginia, North Carolina, South Carolina, Illinois, and Puerto Rico – in the face of inadequate national protections from EPA.

EPA has repeatedly acknowledged the toxicity, quantity, and dangers of the pollution streams flowing from coal-fired plants. Yet, in this proposal, EPA does analytical backflips and disregards evidence in order to exempt the worst coal-fired plants from existing, feasible, and effective means of controlling water pollution. In the course of doing so, EPA simply refuses to comply with the well-established requirements of the Clean Water Act. This proposal is in effect EPA's attempt to nullify the best available technology requirements set out in the Clean Water Act. And what EPA is doing is not only illegal but contrary to plain common sense.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 5

Comment Excerpt:

Utilities across our region have announced their ability to comply with the requirements of the 2015 ELG Rule. In at least one instance, the utility has spent the money to put in place technology to meet those standards and is seeking to recover those costs, and their permits require them to comply with the 2015 Rule as it now stands.

...This is a proposal that embarrasses an EPA of any political stripe. We encourage EPA to abandon this effort to help out the worst actors in the coal ash industry at the expense of America's communities and clean water.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.

Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 207

Comment Excerpt:

XIX.CONCLUSION

For all of the reasons set forth above, and in the attachments submitted with this letter, the undersigned Commenters strongly urge EPA to abandon the 2019 Proposal to gut the 2015 ELG Rule and instead act swiftly to strengthen it.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 7

Comment Excerpt:

1. Flue Gas Desulfurization Wastewater BAT/PSES
For the flue gas wastewater BAT, EPA justifies its switch from high residence time reduction to low residence time reduction by citing $72 million in annual savings for industry.[56] The agency acknowledges that more toxic selenium will be released as a result and that the proposed BAT's performance is more variable than the 2015 BAT,[57] but claims that the "long-term averages" for the two technologies are similar.[58] Nowhere, however, does EPA discuss quantitatively or qualitatively what the health or environmental effects of higher spikes in selenium will be. Before selecting the BAT, EPA must consider not only cost relative to the 2015 Rule, but also the other statutorily required factors relative to the 2015 Rule. If these short-term spikes in toxic selenium have no health or environmental impact, EPA must say so and explain why it believes

that to be true. Because EPA provides no information about these effects relative to the 2015 Rule, the agency violates its statutory obligation to consider whether its proposed BAT for flue gas desulfurization wastewater is truly "best" at making progress toward eliminating pollution. EPA's approach also results in an arbitrarily lopsided analysis of the BAT, which impermissibly stresses compliance costs while neglecting forgone health and environmental benefits.

56 Proposed Rule, 84 Fed. Reg. at 64,632.
57 Id. at 64,631–32.
58 Id. at 64,631.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law

Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 12

Comment Excerpt:

3. Proposed Overall BAT/PSES for Bottom Ash Transport Water
EPA sets laxer standards for bottom ash transport water because the agency claims that requiring facilities with partially closed systems to switch to fully closed systems would be costly. “While some facilities have controlled or eliminated these challenges with relatively straightforward steps,” says EPA, other plants may require “more extensive process changes and associated increased costs.”[71] The agency “does not find this higher cost to be economically unachievable,” but considers this cost “an additional reason for the EPA not to select closed loop systems as BAT.”[72] As a result, the agency selects as the BAT a “high recycle rate system” that allows daily discharge of polluting transport water.[73]

Yet EPA fails to quantitatively or qualitatively discuss the effects this individual BAT change will have on reasonable progress toward “eliminating the discharge of all pollutants,” or the change’s “non-water quality environmental impact.” By ignoring the likely pollution increase resulting from this change and fixating only on cost, EPA fails the Clean Water’s statutory mandate. The agency also engages in an impermissibly lopsided analysis that emphasizes the Proposed Rule’s effects on compliance costs while neglecting forgone benefits.

71 Id. at 64,635.
72 Id.
73 Id. at 64,636.

Commenter Name: Gary Hess
Commenter Affiliation:
Document Control Number: EPA-HQ-OW-2009-0819-8292-A1
Comment Excerpt Number: 1

Comment Excerpt:

EPA proposes to make the effluent limitations guidelines more lenient in several respects. By redefining the term “transport water”, EPA proposes to narrow the categories of wastewater that are governed by the current effluent limitation guidelines and pretreatment standards in 40 CFR Part 423. See, 40 CFR 423.11(p) (as proposed), and 40 CFR 423.11(p) (current). EPA proposes to relax the effluent limitation related to selenium. See, 84 FR, at 64620, 64622, and 64630. EPA also proposes to relax the requirements governing facilities that would retire by 2028. See: 84 FR, at 64622, 64630, 64640-41, and 64666; and 40 CFR 423.13(g)(2)(i), and 423.13(k)(2)(ii).

EPA’s proposal would also fail to establish effluent limitations governing the discharges of bromide and boron from steam electric power generating facilities, despite the human health benefits that would occur if those pollutants were better controlled by those facilities. See: 84 FR, at 64656; and Good KD, Van Briesen JM, Coal-fired power plant wet flue gas desulfurization bromide discharges to US watersheds and their contributions to drinking water sources, Environmental Science & Technology 53(1):213- 223 (2018).

I oppose EPA's proposal. Relaxing the effluent limitation guidelines is unwarranted. Further, if EPA declines to more aggressively address the harm resulting from bromide and boron discharges, it will have missed an excellent opportunity to cost-effectively protect public health.

I am confident a large number of other commenters will oppose EPA's proposed action; I am happy to rely on their comments to capture many of my concerns as well.

For the above reasons, I urge that EPA withdraw its proposal to revise the effluent limitations guidelines for steam electric power generating facilities.

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 1

Comment Excerpt:

Summary of Comments

AWWA and its partners have long considered discharges of bromide upstream of drinking water facilities to be of significant concern. During the 2013 proposal for the Steam Power ELG[1], as well as several instances since then[2], AWWA and its partners have identified bromide discharges upstream of drinking water facilities as a public health concern and encouraged EPA to take swift and comprehensive action to reduce or eliminate them.

AWWA appreciates that there is considerable discussion of this concern in the current proposal. However, AWWA remains concerned that the proposal does not address the ultimate concern of protecting public health and encourages EPA to revisit the proposal to find ways to comprehensively address the impacts of bromide discharges on downstream drinking water facilities. This includes, but is not limited to:

- Assuring that facilities that choose the Voluntary Incentives Program (VIP) and those who do not both have responsibility for reducing or eliminating bromide discharges from their facilities.
- Choosing the regulatory option that provides the greatest protection to downstream sources of drinking water (option 4).
- If option 4 is not chosen, a combination of multiple actions should be taken to both provide information to the states and downstream water utilities as well as minimize the impacts of bromide discharges.

[1] September 20, 2013 comments from AWWA (https://www.regulations.gov/document?D=EPA-HQOW-2009-0819-4478)

[2] As examples, July 6, 2017 comments from AWWA and NAWC, including several appendices (https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6624), the June 8, 2018 letter from AWWA and AMWA to Administrator Pruitt, and April 17, 2019 comments from AWWA (https://www.regulations.gov/document?D=EPA-HQ-OAR-2018-0794-1152)

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 3

Comment Excerpt:

Bromide should be addressed in both standard regulations and in VIP, and EPA should choose option 4 in the final rule

For facilities that do not opt-in to the Voluntary Incentives Program (VIP), there are still no proposed controls on bromide discharges, other than the vague request for states to examine the issue that is present in the 2015 rule.

EPA recognizes the criticality of addressing the impacts of bromide discharges on downstream drinking water supplies. EPA has reviewed the materials provided by AWWA and other water organizations, as well as undertaken considerable analysis. However, the proposal fails to meaningfully act upon that information, and should be revised to increase public health protections.

EPA has included bromide in VIP but has not put into place any requirements for facilities that do not opt-in to that program. Although EPA attempts to estimate how many facilities will enter that program, each facility's response will be driven by a series of factors and ultimately it is not known how many or which facilities will participate. Therefore, VIP should not be exclusively relied upon for the purposes of protecting downstream drinking water supplies.

EPA should assure that there are requirements to address bromide at all facilities subject to the ELG. These requirements should not rely entirely upon voluntary action by the states. Given the many demands placed upon states and their limited resources, it is unlikely that without a specific requirement states will prioritize acting on a recommendation in the ELG preamble. The final ELG should require that bromide discharges be controlled at the source (e.g., using zero liquid discharge or similar technologies). This could be accomplished through choosing rule option 4 (membrane filtration, a technology currently in use across many industries where challenges such as brine management are readily addressed).

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 11

Comment Excerpt:

Conclusion

Although the discussion of the impacts of bromide discharges to downstream drinking water facilities in this proposal is appreciated, AWWA remains concerned that EPA has not taken stronger action to reduce or eliminate the discharges. Through implementing the recommendations contained within these comments, EPA can help to fulfil its mission of protecting the public health.

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 1

Comment Excerpt:

For the reasons set forth below and regardless of the ultimate regulatory approach with respect to bromine, Tinuum asserts that it is not appropriate for iodine to be included in the Steam Electric ELG.

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 9

Comment Excerpt:

Tinuum supports EPA's proposal to not include iodine within the Steam Electric ELG. Tinuum also opposes the inclusion of any iodine requirements in a final rule, especially as EPA has not proposed any requirements related to iodine. If EPA believes that it may be appropriate to consider regulating iodine (which we do not), it should be done in a separate rulemaking process after obtaining, through scientifically-valid additional information collection requests, and reviewing all relevant information related to iodine and determining that this is an issue that requires a one-size-fits-all national rule.

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 2

Comment Excerpt:

In the proposal, EPA presents four compliance options for FGD wastewater and Bottom Ash Transport Water (BATW). EPA is proposing to establish BAT effluent limitations based on the technologies in Option 2. For Cardinal, this means the use of chemical precipitation (CP) with the addition of low hydraulic residence time biological treatment (LRTR) for FGD wastewater and high recycle rate for BATW. EPA notes a significant increase in benefits by setting limitations on Option 2 rather than Option 1. Option 1 consists of chemical precipitation for FGD wastewater and high recycle rate for BATW. EPA states in the supporting documentation that benefits would primarily be seen in the categories of Human Health and Ecological Conditions and Recreational Use Changes. However, EPA's estimated industry-wide cost estimates for Option 2 compliance outweigh benefits by up to 90%.

Buckeye's position is these compliance costs would be better spent on other environmentally beneficial projects – directly contributing toward health or ecological programs – achieving equivalent benefits without incurring additional costs for cooperative members. Buckeye advocates the use of Option 1 technologies to develop BAT limits rather than Option 2 as proposed.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 10

Comment Excerpt:

No evidence in the Record of any other Indirect Dischargers with existing Chemical Precipitation or Indirect Dischargers of FGD Waste that have not announced closure

CWLP recognizes that some of the site-specific factors identified so far in these comments do not necessarily, in and of themselves, justify deviations in a nation-wide standard. However, factors unique to CWLP would be highly relevant to the setting of a national standard if CWLP were determined to be the only facility in the Nation impacted by the FGD PSES.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 15

Comment Excerpt:

While CWLP is willing to make the case to USEPA that it meets the "fundamentally different factors test" that would justify it receiving a variance from this PSES, it would seem that doing so would negate the need for this category of sources altogether.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 30

Comment Excerpt:

Possible Impact on DOE grant award to study Carbon Capture at Dallman Unit 4

CWLP has been selected as the host site for a carbon capture pilot study that will be funded by the U.S. Department of Energy with matching funds provided by the University of Illinois' Prairie Research Institute and its Partners. CWLP is concerned that adoption of the PSES ELG for FGD wastewater may have negative impacts on the ability of that project to go forward under the schedule proposed. CWLP has provided, as Exhibit E to these comments, a copy of the comments submitted by the project's Principal Investigator, Dr. Kevin C. O'Brien, Director of the Illinois Sustainable Technology Center and the Illinois State Water Survey within the Prairie Research Institute.

Commenter Name: Major L. Clark, III and David Rostker
Commenter Affiliation: Office of Advocacy, U. S. Small Business Administration
Document Control Number: EPA-HQ-OW-2009-0819-8310-A1
Comment Excerpt Number: 7

Comment Excerpt:

EPA has not cured the 2015 rule's noncompliance with the Regulatory Flexibility Act.

Although EPA supports the policies of this proposed rule, Advocacy notes that this reconsideration has not cured the problems Advocacy identified in comments on the proposed rule[15] and in support of the UWAG petition.[16] For this proposed rule, EPA treats the 2015 rule as a baseline, considering only the impacts of the changes from the final rule, which never took effect, and not showing the overall impact in the absence of this single extended rulemaking. By conducting its analysis of small entity impacts in this manner, it leaves the original 2015 rule incomplete. The appropriate course of action would have been to re-propose not just changes to the 2015 rule but the 2015 rule in its entirety, as Advocacy recommended in 2017.

[15] Letter from Chief Counsel Winslow Sargeant "Re: Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Docket ID No. EPA-HQ-OW-2009-0819, 78 Fed. Reg. 34432 (June 7, 2013)", September 19, 2012, available at regulations.gov Document ID EPA-HQ-OW-2009-0819-4477.
[16] Supra note 8 [Petition for Reconsideration of EPA's Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category, (March 25, 2017), available at regulations.gov, Document ID EPA-HQ-OW20009-0819-6478].

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 1

Comment Excerpt:

Buckeye also endorses and generally supports the position of the National Rural Electric Cooperative Association (NRECA), the Utility Water Act Group, and America's Power. Additionally, Buckeye supports the research conducted by the Electric Power Research Institute and the comments on technology cost and feasibility of achieving proposed limits.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 2

Comment Excerpt:

Ensure an accurate and robust assessment of costs and benefits and minimize the risk of unavoidable non-compliance: EPA should ensure accurate costs and corresponding benefits for the proposed best available technology economically achievable ("BAT") selections and, when deriving numeric limits for FGD wastewater, should only include data that are representative of the industry and obtained through appropriate methods. EPA should authorize limited purging of bottom ash systems when needed and supported through responsible operational practices.

Commenter Name: Gary Spitznogle
Commenter Affiliation: American Electric Power (AEP)
Document Control Number: EPA-HQ-OW-2009-0819-8489-A1
Comment Excerpt Number: 1

Comment Excerpt:

REDACTED - COMMENT EXCERPT/RESPONSE CONTAINS CONFIDENTIAL BUSINESS INFORMATION.

See CBI_SE08653_AEP Comment Letter_EPA-HQ-OW-2009-0819-8489-A1.pdf for the full comment letter.

3a <u>Regulatory Options – Definition and Reg Language</u>

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 9

Comment Excerpt:

As an initial matter, EPA should clarify the language used in the preamble and the proposed rule to clearly distinguish between the terms “discharge” and “purge,” as EPA seemingly uses them interchangeably which may lead to confusion when applied to real-world scenarios. Berkshire Hathaway Energy believes an appropriate distinction is that “discharge” indicates the flow of wastewater into a regulated waterbody, while “purge” indicates blowdown from a BA handling system.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 36

Comment Excerpt:

VI. EPA Should Amend the Definitions of “Transport Water” and the Term “Maintenance Purge Water.”

EPA has proposed several helpful amendments to the definition of “transport water.” Under the proposed definition, “transport water” would not include wastewater from “cleaning FGD paste transportation piping, wastewater present in equipment when a facility is retired from service, or maintenance purge water.” Proposed § 423.11(p). UWAG recommends a few revisions to the proposed changes, primarily to increase clarity and consistency within the rule.

First, the phrase “FGD paste transportation piping” appears intended to exempt any small amount of ash transport water that may be present in FGD paste due to the mixing of fly ash or bottom ash with FGD solids as a part of making FGD paste that then will be pumped to a landfill for disposal. But the process of making FGD paste may include other pieces of equipment that also need to be cleaned. For instance, facilities may use pugmills to mix fly ash or bottom ash with FGD solids or FGD brine for disposal. The pugmills also will need to be cleaned from time to time, and there may be trace amounts of ash transport water in the cleaning rinse water. Therefore, UWAG recommends that the proposed phrase be replaced with the following phrase:

"Transport water does not include … **wastewater generated from the cleaning of pugmills, piping, or other equipment used to make, process, or transport FGD brine or paste."**

Second, EPA proposes an exemption from the category of "transport water" for "wastewater present in equipment when a facility is retired from service." Proposed § 423.11(p). UWAG recommends augmenting "equipment" with additional language, such as "wastewater present in equipment, piping, hoppers, tanks, basins, or other components." This wording will make it clear that, when a BATW treatment system is decommissioned, the wastewater in all of its components (including hoppers, tanks, and basins) is exempted from categorization as "transport water." Also, as discussed in Section XIX, UWAG recommends adding repowered units to the "retired from service" definition. When a unit is repowered with natural gas or some other non-coal fuel source, it will be necessary to drain all BATW out of the BATW treatment system. Because repowering a unit using a non-coal fuel source eliminates the generation of BATW—just as retiring the unit does—the same exemption from the category of "transport water" should be extended to BATW remaining within the treatment system at the time of repowering.

Third, EPA proposes to exclude "maintenance purge water" from categorization as transport water. EPA would define "maintenance purge water" as "water being discharged subject to §§ 423.13(k)(2)(i) or 423.16(g)(2)(i)." Proposed § 423.11(cc). "Maintenance purge water" is a misnomer because waters discharged under Proposed § 423.13(k)(2)(i) include waters that are not related to maintenance events. There are four conditions under this section in which BATW may be discharged, and only one of them is explicitly related to maintenance events (§ 423.13(k)(2)(i)(A)(3)). The other conditions allow discharges related to storm events, water imbalances, and system chemistry maintenance. Proposed §§ 423.13(k)(2)(i)(A)(1), (2) and (4). Since BATW purge water will consist of all of these kinds of discharges, the "transport water" exclusion should be clear that all types of bottom ash purge water are exempted.

In summary, UWAG recommends that the definition of "transport water" be amended to read as follows (changes in bold):

The term transport water means any wastewater that is used to convey fly ash, bottom ash or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping), minor maintenance events (e.g., replacement of valves or pipe sections), **water generated from the cleaning of pugmills, piping, or other equipment used to make, process, or transport FGD brine or paste, water present in equipment, piping, hoppers, tanks, basins, or other components when the unit is repowered or retired from service, or bottom ash purge water**.

In addition, the proposed term "maintenance purge water" (Proposed § 423.11(cc)) should be renamed "bottom ash purge water" and should be defined to include all types of allowed discharges from BATW systems, including those related to storm events, water chemistry management, water imbalances, and maintenance events.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 13

Comment Excerpt:

EPA is proposing to modify the definition of bottom ash transport water "to exclude water remaining in a tank-based high recycle rate system at the end of the useful life of the facility." 84 Fed. Reg. 64630. GenOn supports this proposed modification. The schedule and cost for off-site transportation and disposal of this wastewater at retirement would be significant.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 16

Comment Excerpt:

As an alternative, TVA recommends that EPA consider redefining the 10% allowable purge from BATW systems as low volume wastes (LVWs). Overall, the amount of BATW discharges nationwide will be greatly reduced by the high recycle requirements of the 2019 ELGs. Both 10% purge volumes and discharges at unit retirement are minimal in comparison to the previous sluice discharge volumes so there will be a significant overall reduction in the national pollutant loading and water withdrawals achieved by the 2019 ELGs. It therefore seems reasonable to set BAT equal to BPT limitations for closing sites and discharges of purge from high recycle systems equal to the existing ELGs for low volume wastes (i.e., ELGs for total suspended solids (TSS) and oil and grease).

To accomplish this, EPA could update the definition of low volume waste sources to include the allowable BATW purge water as follows:

"The term low volume waste sources means, taken collectively as if from one source, wastewater from all sources except those for which specific limitations or standards are otherwise established in this part. Low volume waste sources include, but are not limited to, the following: Wastewaters from ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, recirculating house service water systems, **bottom ash purge water in compliance with 423.13(k)(2)(i)A) or 423.16(g)(2)(i)(A)**, and wet scrubber air pollution control systems whose primary purpose is particulate removal. Sanitary wastes, air conditioning wastes, and wastewater from carbon capture or sequestration systems are not included in this definition."

Categorizing the 10% BATW purge as LVWs make sense because the remaining volume is a low volume waste especially when it is compared to the water used for sluicing bottom ash (BA) prior to the BATW high recycle system. For example, at TVA's Bull Run facility prior BA sluice discharges averaged approximately 6.5 million gallons per day (MGD). The preliminary estimated 10% BATW purge allowance for Bull Run is approximately 43,000 gallons per day (gpd) or 0.043 MGD. This comprises an estimated 0.7% of the former discharge from BA sluicing. Similarly, the 10% BATW purge volumes are under 1% at both Cumberland and Gallatin compared to the former quantities of BA sluice water at these sites.

The long term average flow from the sump currently handling most of the LVW at Bull Run (2016 NPDES permit application update) is an estimated 1.1 MGD. The preliminary maximum amount of BATW was purged daily that may or may not be necessary.) Cumberland and Gallatin's estimated 10% BATW purge would add 6.6% and 3.5% to their LVW flows, respectively. Consequently, TVA believes that defining the 10% BATW purge as LVWs and setting BAT equal to BPT limitations for TSS is a reasonable approach for this rulemaking.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 23

Comment Excerpt:

TVA requests that EPA clarify and/or amplify the bolded terms in its definition of the primary active wetted BA system volume cited on Page 64666 and Part 423.11(aa) "which means the maximum volumetric capacity of BA transport water in all piping (including recirculation piping) and primary **tanks** of a wet bottom ash system, excluding the volumes of installed spares, redundancies, maintenance tanks, **other secondary bottom ash system equipment**, and non-bottom ash transport systems that may direct process water to the bottom ash system ... " The first bolded term could be misconstrued to exclude other equipment in the train and should be modified to "tanks and equipment such as hoppers, clarifiers if present, submerged flight conveyors, hydrobins, etc.). The second term "other secondary bottom ash system equipment" is confusing and is not defined in the rule so it's not clear what the EPA is excluding. The "secondary bottom ash equipment" term should either be defined or omitted.

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 2

Comment Excerpt:

CE generally supports the NOPR with certain modifications including amending the definition “retired from service.”

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 6

Comment Excerpt:

The NOPR revises the term "transport water" to

> "…any wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping), minor maintenance events (e.g., replacement of valves or pipe sections), cleaning FGD paste transportation piping, **wastewater present in equipment when a facility is retired from service**, or maintenance purge water."[2]

The exemption of "*wastewater present in equipment when a facility is retired from service*" appears to address bottom ash transport water remaining on a site at decommissioning. While CE supports an end-of life decommissioning exemption, this exemption should not be limited to wastewater present only in "equipment." Rather, the definition should explicitly include other site locations containing similar wastewater at the time of a facility's retirement. For example, equipment should include legacy bottom ash transport water present in surface impoundments and clarifying basins, as these are integral units used in settling out bottom ash and, under the NOPR, are used as a basis for BAT effluent limitations for units retiring by 2028. The rule should allow a NPDES permittee to dewater end of life equipment and legacy storage ponds, utilizing appropriate best management practices and meeting all permit limits.

2 84 FR 64672, 40 CFR 423.11(p).

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 7

Comment Excerpt:

The NOPR adds the term "retired from service" to mean:

> "…the owner or operator of a boiler no longer has, or is no longer required to have, the necessary permission through a permit, license, or other legally applicable form of permission to conduct electricity generation activities under Federal, state, or local law,

> irrespective of whether the owner and operator is subject to this part."[3]

CE recommends amending this definition. It is not uncommon for generating stations, comprised of multiple units (i.e., boilers), to retire those units independently, and at different times. The proposed definition does not adequately address the fact that an owner or operator may retain permits or licenses for a site, while also retiring individual or multiple units at that site. For example, at our Karn site, Units 1 and 2 are coal-fired, baseload units while Units 3 and 4 are oil-fired, peaking units. As mentioned above, Units 1 and 2 will be retired in 2023, but Units 3 and 4 will continue to operate past 2028. The site will need to retain its license, permits, etc. to generate electricity after Units 1 and 2 retire. CE recommends that a certification statement signed by a "responsible corporate officer"4 is sufficient for documenting when electric generation has ceased.[5]

3 84 FR 64672, 40 CFR 423.11(w).
4 40 C.F.R. § 122.22(a)(1) ("a responsible corporate officer" means: "(i) A president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision making functions for the corporation or (ii) the manager of one or more manufacturing, production, or operating facilities, provided the manager is authorized to make management decisions which govern the operation of the regulated facility…."
5 Certification statements by a responsible corporate officer under the NPDES permitting program (40 CFR Part 122.22) are legally binding and sufficient for submitting documents such as a permit application (40 CFR Part 122.21).

Commenter Name: Usha-Maria Turner
Commenter Affiliation: Oklahoma Gas and Electric Company (OG&E)
Document Control Number: EPA-HQ-OW-2009-0819-8290-A1
Comment Excerpt Number: 3

Comment Excerpt:

C. EPA Should Revise the Definition of "Primary Wetted Bottom Ash System Volume" Definition to Provide Greater Clarity

In response to EPA' s request for comments, [8] OG&E respectfully requests that EPA refine the definition of "primary wetted bottom ash system volume" for a given facility to include nonCoal Combustion Residual (CCR)-containing surface impoundments, [9] and clarify in the preamble to the final rule that the volume generally can be calculated on a case-by-case basis by the permitting authority based on the specific BA TW treatment system in place at that facility.

EPA proposes to define "primary active wetted bottom ash system volume" as the "maximum volumetric capacity of bottom ash transport water in all piping (including recirculation piping) and primary tanks of a wet bottom ash system, excluding the volumes of installed spares, redundancies, maintenance tanks, other secondary bottom ash system equipment, and non-bottom ash transport systems that may be used to direct process water to the bottom ash system[.]"[10] OG&E supports the proposed definition because it is encompasses the wide variety of high recycle rate bottom ash transport systems used by companies, but believes two changes to the definition are warranted to provide clarity to regulators and the regulated industry.

First, EPA should amend the "primary active wetted bottom ash system volume" definition to include non-CCR surface impoundments in addition to primary tanks. OG&E understands that EPA is not proposing to identify CCR surface impoundments "as BAT for BA transport water except for BA TW purge water because surface impoundments are not as effective at removing dissolved metals as available and achievable technologies, such as high recycle rate systems."[11] Facilities like OG&E's, however, utilize surface impoundments in their BATW treatment system that do not meet the definition of a "CCR surface impoundment" under the federal CCR rule [12] such as cooling basins and evaporation ponds. [13] In many instances, facilities have been relying on these types of units since before the finalization of the 2015 CCR rule. These types of surface impoundments are integral to the overall BA TW treatment system and therefore should be included in the calculation of"primary active wetted bottom ash system volume."

Second, OG&E urges EPA to clarify in the preamble to the final rule (or in the regulation itself) that companies can work with the permitting authority as part of the permit process to describe their specific system and components thereof, and define in the permit what system components will be used in the calculation of "primary active wetted bottom ash system volume" for their particular facility. OG&E agrees, as EPA currently contemplates in the preamble to the Proposed Rule, that facilities should "submit the calculation of the primary wetted BA system volume" to enable the "permitting authority [to] verify the volume of discharge allowed for a high recycle rate system."[14] EPA should further confirm, however, that companies in conjunction with the permitting authority can determine which components of a given BA TW system should be included in the calculation of the primary wetted system volume. This will provide flexibility and clarity to regulators and companies as they work together to implement the revised BA TW ELG.

[8] Proposed Rule, 84 Fed. Reg. 64,666.
[9] I.e., surface impoundments that do not meet the definition of CCR surface impoundment as defined in the federal CCR Rule published in 2015 at 80 Fed. Reg. 21,357.
[10] Proposed Rule, 84 Fed. Reg. at 64,672.
[11] Proposed Rule, 84 Fed. Reg. at 64,636.
[12] 40 C.F.R. § 257.53.
[13] See, e.g., EPA CCR FAQs, available at https://www.epa.gov/coalash/frequent-questions-about-definitions-andimplementing-final-rule-regulating-disposal-coal ("Surface runoff, coal pile runoff, CCR landfill leachate, stonnwater and evaporation ponds would not generally be expected to meet the definition of a CCR surface impoundment, because based on their typical design and function, such units are not usually designed primarily to hold an accumulation of CCR and liquid and would not be expected to treat, store, or dispose of CCR.").
[14] Proposed Rule, 84 Fed. Reg. at 64,666.

Commenter Name: Patti Hershey
Commenter Affiliation: Lower Colorado River Authority (LCRA)
Document Control Number: EPA-HQ-OW-2009-0819-8317-A1
Comment Excerpt Number: 2

Comment Excerpt:

II. EPA Should Clarify that Recycling Is Not a Technology

The Clean Water Act authorizes the EPA to establish national ELGs for discharges into WOTUS from categories of point sources that may be located at power plants. To develop ELGs, EPA first gathers information on industry practices and technologies or practices used to prevent or treat the discharge. EPA identifies Best Available Technology (BAT) that is economically achievable for that industry and sets regulatory requirements based on the performance of that technology. The ELGs do not require facilities to install the particular technology identified by EPA. However, EPA does require facilities to achieve regulatory standards based on the selected technology.

In the Proposed Rule preamble, EPA describes recycling appropriately as an "operating or management practice" and not as a "technology" and recognizes that "operating and management practices" may eliminate discharges to WOTUS:

Steam electric facilities discharging FGD wastewater currently employ a variety of wastewater treatment technologies **and operating/management practices** to reduce the pollutants associated with FGD wastewater discharges. As part of the 2015 rule, the EPA identified the following types of treatment and handling practices for FGD wastewater:

- Some facilities operate their wet FGD systems using approaches **that eliminate the discharge of FGD wastewater.** TThese facilities use a variety of operating and management practices to achieve this.
  - Complete recycle ....
  - Evaporation impoundments. Some facilities in warm, dry climates have been able to use surface impoundments as holding basins from which the FGD wastewater evaporates. The evaporation rate from the impoundments at these facilities is greater than or equal to the flow rate of the FGD wastewater and amount of precipitation entering the impoundments; **therefore, there is no discharge to surface water.**
  - Combination of wet and dry FGD systems ....
  - Underground injection ....

84 Fed.Reg. at 64627 (Nov. 22, 2019) (emphasis added).

However, in other parts of the Proposed Rule preamble, EPA appears to contradict these statements and appears to incorrectly refer to recycling as an ELG "technology":

After accounting for the changes in the industry described in Section V of this preamble fifteen steam electric facilities with wet scrubbers have technologies in place able to meet the proposed BAT effluent limitations for FGD wastewater. [17]

17 The EPA notes that a further 40 percent of all steam electric facilities with wet scrubbers use FGD wastewater management approaches that eliminate the discharge of FGD wastewater altogether. But, although these technologies (which are described above in Section V.C.1) may be available for some facilities, none of them are

available nationwide, and thus do not form the basis for the proposed BAT. For example, evaporation ponds are only available in certain climates. Similarly, complete recycle FGD systems are only available at facilities with appropriate FGD metallurgy. Facility conditions and availability of these technologies have not materially changed since the 2015 rule, and the EPA thus reaffirms that these technologies are not individually available nationwide and are not a basis for the proposed BAT.

84 Fed.Reg. at 64631 and footnote 17 (Nov. 22, 2019) (emphasis added).

The LCRA asserts that the recycling of wastewaters is an "operating or management practice" and not a "technology" and requests that EPA revise and clarify the preamble text on page 64631 and accompanying footnote 17. Describing recycling as a technology presupposes incorrectly that a facility using recycling is essentially operating under the ELG rules. Recycling FGD wastewater is not a method of treating wastewater such that pollutants are removed or minimized in order to meet an effluent limit, but instead is a facility decision to manage FGD wastewater such that no discharge results. The distinction is important because when a facility utilizes recycling , it removes the FGD wastewater from the applicability of the Clean Water Act entirely. NPDES only applies to "discharges to waters of the U.S." and, therefore, "recycling" should not be represented as a control technology.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 16

Comment Excerpt:

VIII. EPA SHOULD AMEND THE DEFINITION OF "TRANSPORT WATER"

EPA has also proposed to modify the definition of "transport water." Transport water means any wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection, storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping), minor maintenance events (e.g., replacement of valves or pipe sections), cleaning FGD paste transportation piping, wastewater present in equipment when a facility is retired from service, or maintenance purge water.39 We have some concerns about only including transport water in "equipment" and not broadening the definition.

EPA proposes an exemption from the category of "transport water" for "wastewater present in equipment when a facility is retired from service." [40] The Association recommends modifying "equipment" with additional language, such as "wastewater present in equipment, piping, hoppers, tanks, basins, or other components." This level of detail makes it clear, when a BA transport water treatment system is decommissioned, the wastewater in all of its major components (including hoppers, tanks, and basins) is exempted from categorization as "transport water." APPA also recommends replacing "retired from service" with "repowered or retired from service." When a unit is repowered, it will be necessary to drain all BA transport water out of the BA treatment system. Therefore, the same exemption from the category of "transport water" should be extended to BA transport water remaining within the treatment system at the time of repowering.

40 Id.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 52

Comment Excerpt:

To that end, EPA should broaden the proposed term "retired from service" to better accommodate repowering. As proposed, the term "retired from service" means "the owner or operator of a boiler no longer has, or is no longer required to have, the necessary permission through a permit, license, or other legally applicable form of permission to conduct electricity generation activities under Federal, state, or local law, irrespective of whether the owner and operator is subject to this part."[83] The "retired from service" phrase should be replaced with "cease coal-fired boiler operation" or similar language. A change to this effect ensures that repowering is permissible even though the repowered unit will continue to conduct electricity generation activities. This proposed change is also congruent with the provisions in the federal CCR rule for the "cessation of a coal-fired boiler[.]"[84]

83 Id. at 64,672 (to be codified at 40 C.F.R. § 423.11(w)) (emphasis added).
84 40 C.F.R. § 257.103(b)(1). For some instances of repowering, however, the boiler itself might not cease operations altogether; it might be retooled to burn a different fuel. Southern Company therefore recommends slightly different wording than that used by the CCR rule.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 104

Comment Excerpt:

The permittee cannot be assured that the license withdrawal requirement EPA proposes in the definition of "retired from service" can be timely fulfilled, despite the permittee's best efforts to accomplish this step. A backlog of applications for license modifications, for instance, could jeopardize a permittee's compliance with its retirement or repowering certification.

For this reason, the certification statement should be self-implementing (i.e., effective upon the submittal of the certification by the permittee) and not dependent on any actions by third parties.

UWAG's recommendation (a certified letter signed by responsible corporate official) would be within the permittee's control and legally binding. Nothing further should be required.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 33

Comment Excerpt:

5. EPA Should Clarify the Components of the BA Transport Water System Used to Calculate Primary Active Wetted BA System Volume

The Proposed Rule includes new reporting and recordkeeping standards for facilities operating high recycle rate BA transport systems. These facilities must submit calculations of the primary wetting system maximum volume of BA transport water in all piping. EPA is seeking comment on specific components of the BA transport water system that should be included or excluded from the calculation. [32] The Association recommends that volume calculation should include all system volume in the recirculation loop, to include any equipment, tanks, ponds, impoundments, and open concrete basins. APPA would ask EPA to clarify in the final rule that permittees can work with their permitting authority as part of the permitting process to specify systems or components thereof and define in the permit what system components will be used to calculate "primary active wetting bottom ash system volume." This provision would provide flexibility and clarity as facilities work to implement the ELG Rule.

32 84 Fed. Reg. at 64,666.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 5

Comment Excerpt:

<u>EPA Should Consider Including All BA System Components in the Definition of "primary active wetted bottom ash system volume"</u>

EPA proposes to allow wet BA transport water systems to discharge on a not to exceed a 30-day rolling average of 10% of the primary active wetted bottom ash system. EPA proposes to limit the primary active wetted bottom ash system to piping and primary tanks and exclude maintenance tanks and other secondary bottom ash system equipment. However, EPA should include the volumes of installed spare equipment, maintenance tanks, other secondary bottom ash system equipment, and non-bottom ash transport systems in the bottom ash wetted volume calculation to ensure consistent implementation across the industry and not disproportionately affect those stations that have already installed high recycle rate systems. Tanks are routinely used in a RMDS to equalize volume and provide surge capacity. A tank designated for holding the system contents (e.g., a maintenance tank) may also be used to periodically equalize RMDS flows and should be included in the system volume to calculate the percent purged allowance. These components are integral parts of the BA treatment system and should not be excluded from the wetted bottom ash system volume calculation.

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 8

Comment Excerpt:

CE seeks further clarification of the 30-day rolling average for transport water discharge of ten percent of the primary active wetted bottom ash system volume. The ten percent purge volume is based on the "primary active wetted bottom ash system volume." EPA defines this proposed term as the

"…maximum volumetric capacity of bottom ash transport water in all piping (including recirculation piping) and primary tanks of a wet bottom ash system, excluding the volumes of installed spares, redundancies, maintenance tanks, other secondary bottom ash system equipment, and non-bottom ash transport systems that may direct process water to the bottom ash system as certified to in paragraph 423.19(c)."[6]

CE's J.H. Campbell Units 1 - 3 site uses a concrete tank-based handling system for wastewater treatment and settling of bottom ash from transport water for all three units. As mentioned previously, retrofits will be needed to convert to a high recycle rate system under this proposed rule. The concrete tank-based handling system is currently designed with two primary tanks, two secondary tanks, and one tertiary tank all interconnected as part of gravity settling prior to discharge. Based on this proposed definition, J. H. Campbell's secondary and tertiary tanks would not be included in the primary active wetted bottom ash system volume. While most gravity settling in the bottom ash tank system occurs in the primary tank, the secondary tanks provide additional hydraulic residence time to remove any residual ash, as well as provide for additional treatment, such as potential polymer addition. These secondary tanks will be an integral part of maintaining water balance within the high recycle rate system and as such, they should be included in the definition of "primary active wetted bottom ash system volume." If they are not, the volume of purge allowed could potentially limit the ability to maintain water balance and water quality within the system.

In addition, it is not uncommon for sites with multiple units to retire individual units at different times. At CE's J.H. Campbell site, Units 1 and 2 are scheduled to shut down in 2031, nearly a decade before Unit 3's retirement in 2040. However, all 3 units currently share a bottom ash treatment system, and thus likely share a combined high recycle rate system under the NOPR. Consumers Energy is concerned that the proposed rulemaking does not address how the "primary active wetted bottom ash system volume" and 10 percent purge volume should be adjusted, if at all, when the water volume required for ash handling changes due to partial unit retirement. CE requests EPA clarify that partial unit retirements does not change the calculation of the "primary active wetted bottom ash system volume," or associated 10 percent purge volume, made when the high recycle rate system is initially installed. The contrary situation - requiring the volumes to be adjusted when a unit retires - may create substantial retrofitting costs to the high recycle rate system. Thus, CE recommends that the primary active wetted bottom ash system volume remain the same after a unit© retires from a shared high recycle rate system.

6 84 FR 64672, 40 CFR 423.11(aa)

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 8

Comment Excerpt:

EPA should amend the proposed definition of "primary active wetted bottom ash system volume." Alternatively, EPA should permit facility-specific alternatives to the 10% limit for volumetric purges.

Cleco applauds the Agency for reconsidering the zero-discharge limitations on BATW and identifying high recycle rate systems as the more appropriate model technology.[43] While this is a welcome change, Cleco submits that the newly proposed standards can be better calibrated to avoid unnecessary costs. EPA should particularly broaden the definition of "primary active wetted bottom ash system volume" beyond only that for the system's "piping" and "primary tanks[.]"[44] As a second-best change, EPA should authorize the use of facility-specific alternatives to the 10% limit on volumetric purges in the proposed rule.

[43] See, e.g., Proposed Rule, 84 Fed. Reg. at 64,634.
[44] Id. at 64,672 (to be codified at 40 C.F.R. § 423.11(aa)).

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 9

Comment Excerpt:

1. Primary Active Wetted Bottom Ash System

The Agency has requested "comment on the specific components of the BA transport water system that should be included and/or excluded from the calculation of primary active wetted BA system volume."[45] Cleco urges EPA to expand the list of components beyond piping and primary tanks. While these components should be included in the final definition, they do not identify all primary components of high recycle rate systems. Most notably, limiting the volume of storage components to tanks implicitly excludes impoundments or basins.[46] These excluded components are properly considered part of well-functioning high recycle rate systems and should be included in the final definition.

Impoundments or basins bring several benefits to BATW recycling. First, because most coal-fired facilities have employed impoundments in some capacity prior to the 2015 rule, these structures are readily available and do not require new capital outlays. Their use in a closed-loop system is therefore efficient from a cost perspective. Second, impoundments also perform a trnatment function on circulating BATW, allowing some constituents to settle out before the transport water is recycled. Third, impoundments provide a significant margin of capacity for the BATW system. By providing spare volume that can be used quickly, cheaply, and safely, impoundments can reduce the likelihood that a facility needs to discharge maintenance purge water at all. One permissible condition for discharge, for instance, arises from inflows of other wastesh·eams that disrupt the BATW system's water balance.[47] An impoundment can help absorb those inflows; this buffer function might prove particularly important for facilities that are unable to send excess BATW to the FGD system as makeup water.[48] These benefits make surface impoundments presumptively worthy of inclusion.

Cleco has not identified an explicit justification for the proposed definition in the preamble or supporting record. At most, it can discern two conceivable reasons why impoundments might not be included in the calculation of the BATW system's recirculating volume. Neither reason warrants a flat ban on impoundments as part of high recycle rate systems.

First, the preamble acknowledges a proposed amendment to the Coal Combustion Residuals ("CCR") Rule that would prohibit sending BATW to unlined or clay-lined surface impoundments by August 2020.[49] This is not a valid basis for excluding the use of all impoundments from closed-loop BATW operation. For one thing, the proposed amendments are not yet final and might be modified, abandoned, or vacated after adoption. [50] Nor does the August 2020 prohibition apply to lined impoundments that meet the requirements of the CCR Rule. Facilities can in fact continue to build new lined impoundments for the foreseeable future. [51] In fact, as the preamble itself notes, even "an *unlined* surface impoundment could continue to receive waste and complete closure by 2028" under the CCR Rule's alternative closure provisions. [52]

And even for unlined impoundments that will close relatively soon, there is no reason to exclude their use in the interim. Impoundments can provide a cost-efficient, short-term solution to reduce maintenance purge water discharges. Finally, excluding surface impoundments also seems inconsistent with other aspects of the proposed rule. Some proposed BAT standards, for instance, contemplate the continued use of surface impoundments.[53]

All of these reasons point to the same basic conclusion: Effluent limitations guidelines are not meant to effectuate policies outside the Clean Water Act and should therefore not put a thumb on the scales against surface impoundments. The final rule should remain at least neutral with respect to their use for high recycle rate systems and permit facilities to employ them as they see fit.

The second reason EPA might have excluded impoundments could be their exposure to precipitation; the Agency might have some concern that introducing stormwater can increase the frequency or extent of maintenance purge water discharges. [54] Once again, Cleco sees several problems with this possible explanation. First, the proposed rule necessarily assumes some permissible level of stormwater exposure for any closed-loop system. The volumetric purge authorization expressly contemplates discharges arising from water imbalance caused by large or frequent storms. [55] It cannot be the case, then, that the possibility of exposure to rain rules out impoundments. [56]

Second, the contribution of any particular impoundment to precipitation-related inflows depends on several site-specific factors. If the impoundment's remaining capacity exceeds the amount of precipitation received, it might instead absorb inflows that would otherwise overwhelm other parts of the system. Or an impoundment in a warm climate might experience an evaporation rate that exceeds the rate of inflows. These are inherently local considerations that should be weighed by the facility and its permitting authority.

[45] Id. at 64,666.
[46] The proposed definition of"tank" includes containment structures built "primarily of non-earthen materials[.]" Id. at 64,672-73 (to be codified at 40 C.F.R. § 423.11(bb)).
[47] See id. at 64,674 (to be codified at 40 C.F.R. § 423.13(k)(2)(i)(A)(2)).
[48] See Email from Nicholas M. Dernik, Dir., Envtl. Permitting, NiSource Inc., to Richard Benware, EPA (June 8, 2018) (Docket No. EPA-HQ-OW-2009-0819-8275) (explaining that facilities with dry FGD systems are particularly in need of the ability to purge some BATW).
[49] See Proposed Rule, 84 Fed. Reg. at 64,626; see also A Holistic Approach to Closure Part A: Deadline To Initiate Closure, 84 Fed. Reg. 65,941, 65,942 (proposed Dec. 2, 2019).
[50] Similarly, EPA might ultimately decide to better justify the classification of clay-lined impoundments as equivalent to lined impoundments by the time it finalizes its currently proposed amendments to the CCR Rule.
[51] See 40 C.F.R. § 257.72 (creating performance standards for the design of new lined impoundments). Record information indicates that there are least 47 lined impoundments; any number of these might be used as part of a closed-loop system. See EPA, ORCR CCR Impoundment Status Information Collected for CCR Rule (2018) (Docket No. EPA-HQ-OW-2009-0819-7580).
[52] Proposed Rule, 84 Fed. Reg. at 64,641 (emphasis added) (citing 40 C.F.R. § 257.103(b)).
[53] See, e.g., id. at 64,636 ("For·example, the EPA solicits comment on whether surface impoundments could be selected as BAT based on high costs to control the purge with other technologies.").
[54] Cf id. at 64,675 (to be codified at 40 C.F.R. § 423.13(k)(3)(v)(B)) (requiring measures to "minimiz[e] the introduction of stormwater").
[55] See id. at 64,674 (to be codified at 40 C.F.R. § 423.13(k)(2)(i)(A)(l)).
[56] This is especially true where EPA has not developed record evidence to justify exclusion of impoundments. The agency bears the burden of doing so when discontinuing their use imposes costs on facility owners.

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC

Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 11

Comment Excerpt:

Third, nothing in the proposed regulatory text for "primary active wetted bottom ash system volume" ensures that other components are not exposed to precipitation-related inflows.The definition of a "tank" does not require a cover or other protection against rain. [59] Thus, to exclude surface impoundments on the basis of potential rain exposure, but not to do the same for other structures simply because their sides are not earthen, seems arbitrary.

Tanks also bring their own disadvantages. Tanks will also often need maintenance, and that maintenance can require taking the tank completely out of the BATW system and fully draining it. Not only does this necessitate investments in spare tanks that might be rarely used, but it might also require additional safety precautions for workers who must physically enter the tank. Nor can a facility be certain that it will have the necessary footprint or infrastructure to accommodate enough tanks to replace current impoundments. [60]

In Cleco's view, there is no defensible reason to bar facilities from integrating impoundments into their high recycle rate systems, and EPA should amend its proposed definition of "primary active wetted bottom ash system volume."

[59] See id. at 64,672-73 (to be codified at 40 C.F.R. § 423.11(bb)).
[60] Notably, the proposed definition of "primary active wetted bottom ash system volume" does not cap the number of "primary tanks" that might be used. See id. at 64,672 (to be codified at 40 C.F.R. § 423.11(aa)). Consequently, there is also no reason to distinguish impoundments and tanks based solely on total volume; even if the average impoundment has higher volume, more tanks could be employed to provide a higher total volume.

Commenter Name: Eric C. Massey
Commenter Affiliation: Arizona Public Service Company
Document Control Number: EPA-HQ-OW-2009-0819-8324-A1
Comment Excerpt Number: 2

Comment Excerpt:

I. Integral Components of BATW Recirculation Systems Should Count Towards the Calculation of a Power Plant's "Primary Active Wetted Bottom Ash System Volume."
EPA's proposal to define the total volume of BATW managed in a given system, of which 10% may be discharged on a 30-day rolling average basis[3], excludes "the volumes of installed spares, redundancies, maintenance tanks, other secondary bottom ash system equipment, and nonbottom ash transport systems that may direct process water to the bottom ash system."[4] Each of these are components of a fully functioning BATW recirculation system and are critical to a properly designed system's function. Excluding these would mean that certain aspects of a BATW recirculation system, which are necessary to address co-mingled low-volume waste flows, along with BATW flows associated with necessary equipment and water-balance maintenance, could not be considered when evaluating the total BATW purge discharges from a given system. Given

the critical importance of BATW recirculation system designs that take into account these functions, excluding this equipment fails to account for their importance. Because these are critical components to a BATW recirculation control system that is up to par with "best industry practices"—as expressly required under Proposed § 423.13(k)(2)(i)(B)—"installed spares, redundancies, maintenance tanks, other secondary bottom ash system equipment, and non-bottom ash transport systems that may direct process water to the bottom ash system" should not be excluded from the calculation of a facility's total "primary active wetted bottom ash system volume."

[3] See, Proposed § 423.13(k)(2)(i)(B)
[4] See, Proposed § 423.11(aa)

3b <u>Regulatory Options – Options Selection and Analysis</u>

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 11

Comment Excerpt:

IV.THE REGULATORY OPTIONS EVALUATED BY EPA DO NOT PROVIDE A MEANINGFUL COMPARISON OF ALTERNATIVES

EPA evaluates four regulatory alternatives – Options 1 through 4 – and compares them to a baseline equivalent to compliance with the 2015 Rule.[60] There are three problems with this range of regulatory options. First, the analyses in the record generally exclude all units slated to retire before 2028. Second, EPA's baseline is not appropriate for estimating the practical consequences of the Proposed Rule. Finally, EPA's range of alternatives fails to capture the potential for much greater and potentially more cost-effective pollution reductions. The record shows that the correct application of the BAT standard would result in a zero-discharge rule for both bottom ash transport water and FGD wastewater, so EPA should model a zero-discharge option.

[60] 84 Fed. Reg. at 64,645; Proposed TDD at 5-1, 6-1.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 14

Comment Excerpt:

C. EPA Fails To Evaluate Regulatory Options That Would Maximize Pollution Reductions

The goal of the Clean Water Act ("CWA") is to eliminate water pollution.[66] EPA must evaluate the most aggressive approach to controlling pollution from the industry in order to determine whether it is or is not possible to achieve the statutory goal. The record shows that it is possible to eliminate all of the pollution associated with bottom ash and FGD systems: EPA concedes that the technologies to eliminate both wastestreams are economically achievable.[67] The record shows that both technologies are available, in use at one or more facilities in the industry.[68] It is therefore incumbent upon EPA to require the elimination of these wastestreams. The Agency cannot disagree without providing a detailed evaluation of the achievability, availability, and impacts (including both costs and pollution reductions) of a zero-discharge rule for each wastestream.

EPA has all of the information it needs to evaluate a zero-discharge regulatory option, or something substantially similar. Such an option would eliminate the exemption for units that are slated to retire by 2028, eliminate the low-utilization subcategory, and calculate costs and pollution reductions associated with the elimination of bottom ash transport water and FGD wastewater. This would allow EPA to evaluate the costs and benefits of an option that is more closely aligned with the zero-discharge goal of the CWA. EPA's failure to evaluate a zero-discharge option – without any subcategories – despite evidence in the record that zero discharge is achievable for both the bottom ash and FGD wastestreams, is arbitrary and capricious.

[66] 33 U.S.C. § 1251(a)(1); see also id. § 1311(b)(2)(A) (BAT effluent limitations "shall require the elimination of discharges of all pollutants if the Administrator finds, on the basis of information available to him (including information developed pursuant to section 1325 of this title), that such elimination is technologically and economically achievable for a category or class of point sources.").
[67] 84 Fed. Reg. at 64,634 ("[C]osts do not make the membrane filtration option economically unachievable."); see also id. at 64,635 ("EPA does not find this higher cost [of closed-loop systems for bottom ash transport water] to be economically unachievable.").
[68] See, e.g., Proposed TDD at 3-9 (showing that the majority of affected plants and units already employ dry bottom ash handling systems); ERG, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019) (identifying numerous zero-discharge pilot studies for FGD wastewater treatment across the country); Email from Greg Johnson, New Logic Research, to Phillip Flanders, Docket ID No. EPA-HQ-OIW-2009-0819-8179 (June 22, 2019) ("Regarding our [membrane] system that was installed at the research center in Atlanta, I can confirm that it is begin [sic] moved to the new location and that it will be a permanent installation to treat about 50 gpm of FGD effluent. This is the total flow that they have and this is not intended to be a pilot, it is a final treatment plant that will be permanent." (emphasis added)).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 161

Comment Excerpt:

EPA's proposed action will increase discharges of nearly all pollutants regulated under the rule with the exception of bromide.[616] Option 4 – as modified to (1) remove the proposed subcategories for high FGD flow plants, low-utilization boilers, and boilers retiring by 2028 and

(2) maintain zero-discharge requirements for bottom ash transport water – is the strongest of the options that EPA analyzed.[617]

Even greater environmental benefits will be realized if EPA adopts – as the Clean Water Act requires – a zero-discharge standard for both bottom ash transport water and FGD wastewater. EPA's Integrated Planning Model ("IPM") analysis, and a supplemental IPM analysis performed by the Natural Resources Defense Council ("NRDC"), show that neither EPA's Option 4 nor a zero-discharge regulatory option would have noticeable effects on coal capacity, grid reliability, or electricity prices, while a zero-discharge option would have far superior environmental benefits.

[616] Id. at 2, 19.
[617] Id. at iii, 20-21.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 162

Comment Excerpt:

A. Structural Flaws in EPA's Analysis Conceal the True Costs of EPA's Proposed Action.

Structural flaws in EPA's Proposed BCA – including an improper baseline and a failure to clearly and transparently state costs and benefits associated with individual program components – obscure the true costs of EPA's proposed action and hinder public assessment of regulatory alternatives.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 176

Comment Excerpt:

C. A Corrected BCA Would Demonstrate that Regulatory Option 4, with Certain Revisions, Is the Only Option Offering a Justifiable Change in Environmental and Health Benefits.

To accurately assess benefits and costs of the proposed rule, EPA must correct the structural flaws in the BCA analysis structure and fully quantify and monetize the costs and benefits of its proposed action. Specifically, EPA should evaluate the impact of the proposed modifications against two new baselines: (1) a corrected existing rule baseline, modified to reflect costs and benefits resulting from ELG compliance with the 2015 rule (as modified by the 2017 postponement rule) as well as regulatory changes and updates to the profile of electric generating facilities announced between October 2018 and July 2019, and (2) a status quo baseline of current (2019) conditions.[662] EPA should also separately and transparently calculate and state the costs and benefits associated with each component of its preferred action and alternatives, including all technology bases, subcategories, and assumptions concerning use of the Voluntary Incentives Program.[663]

Based on its own analysis, Synapse Energy Economics concludes that Option 4 – as modified to (1) remove the proposed subcategories for high FGD flow plants, low-utilization boilers, and boilers retiring by 2028 and (2) maintain zero-discharge requirements for bottom ash transport water – is the only regulatory compliance option offering an acceptable change in the level of environmental and health benefits relative to the 2015 rule.[664]

In addition, as discussed in Section VI – Zero Discharge FGD, EPA must also consider a regulatory option that not only maintains zero-discharge requirements for bottom ash transport water, but that also (unlike Option 4) requires zero discharge of FGD wastewater based on use of membrane treatment or other technologies. A zero-discharge rule would maximize environmental benefits at little additional cost over the effluent limitations for FGD wastewater that EPA evaluated under Option 4, given that it would be based on use of the same treatment technologies. EPA's failure to consider the costs and benefits of a regulatory option that completely eliminates discharges from both bottom ash transport water and FGD wastewater further undermines the legitimacy of its benefit-cost analysis.

[662] 2020 Synapse BCA Analysis at 8, 12, 21.
[663] Id. at 13, 22.
[664] See id. at iii, 20-22.

4 <u>Regulatory Options – BPJ</u>

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 4

Comment Excerpt:

Requiring permit writers to establish "best professional judgement (BPJ)" limits is unnecessary for a well-regulated and minimal BATW purge stream. A BPJ determination is a time-consuming, fact-intensive process that would divert plant and especially state permitting resources for little if any environmental benefit. Adoption of a BPJ approach would also create uncertainty for the regulated community at a point that so much is in flux regarding not only management of coal-fired wastewater and CCR, but other macro changes in the utility sector.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 6

Comment Excerpt:

Finally, EPA's proposal to regulate BATW purge through a "best professional judgment" approach is infeasible for a number of reasons. First, requiring a time-consuming, fact-intensive, site-specific inquiry involving technology evaluations and economic assessments is serious overkill for a well-regulated side stream of BATW. The use of industry and state resources to devise "best professional judgment" limits at each site would be an egregious use of those resources. Requiring best professional judgment limits also undercuts the certainty that the Proposed Rule would otherwise provide. UWAG recommends instead that EPA require permittees to implement a best management practices plan to maximize the recycling of BATW, based on the use of EPA's defined model technology for either remote mechanical drag chain systems or dewatering bin systems.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 26

Comment Excerpt:

A. A BPJ Determination to Establish BAT Is Complex and Difficult to Implement.

A BPJ determination is a complex, multi-step evaluation akin to a comprehensive effluent guidelines development process. According to EPA regulations, the permit writer must consider all of the following factors when setting BPJ BAT limitations:

- the age of equipment and facilities involved;
- the processes employed;
- the engineering aspects of the application of various types of control techniques;
- process changes;
- non-water quality environmental impacts, including energy requirements; and
- the cost of achieving the effluent reduction.

40 C.F.R. § 125.3(d). The permitting authority must assess these factors and then select a model treatment technology and derive effluent limitations on the basis of the selected technology. The "process and the factors considered by the permit writer are the same factors required to be considered by EPA in developing effluent guidelines…." EPA, *NPDES Permit Writers' Manual*, EPA-833-K-10-001 (Sept. 2010) ("Permit Writers' Manual") at 5-46. Finally, the permitting authority then must document both "the approach used to develop the limitations … and how the

limitations carry out the intent and requirements of the CWA and the NPDES regulations." *Id.* at 5-45.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 27

Comment Excerpt:

B. BPJ Limits Increase Uncertainty and Slow Progress.

If EPA were to finalize the rule with the requirement that permit writers set BPJ limits for BATW purge water, it will create great uncertainty for the regulated community. There would be no way of knowing what limits would be applied to the purge water, and facilities therefore could not confidently design their BATW systems to meet the new purge discharge standards. The industry would not know if the purge is subject to limits similar to the existing BPT limits, or if they are subject to additional limits that would require more equipment or additional operational measures. The permittee would have no indication of what limits would apply to the purge until the permitting authority released a draft permit.

Since treating BATW in an RMDS or dewatering bin system already removes the great majority of pollutants, it is all the more uncertain what types of steps or equipment might be employed to remove even more pollutants. All of this uncertainty would act to slow down the design and construction of new BATW treatment, at a time when the industry is already under considerable stress to meet new regulatory requirements under the CCR rule.

Additionally, permittees would bear the burden of supplying information to their regulator to inform the BPJ determination. The permittee likely would be required to investigate potential technologies, assess their engineering feasibility and level of performance, judge whether the technologies would be appropriate for the specific facility or unit, and provide economic information showing why certain technologies are or are not economically reasonable for the facility.[25] But there is no clear guidance on what would be required of the permittee in the manner of supporting documentation for BPJ limits, and each permitting authority would be free to determine the level of documentation it would seek from the permittee. The result could be several rounds of information requests to the permittee.

[25] As discussed later in these comments, EPA acknowledges that its cost estimates do not include any costs associated with BPJ decision-making or compliance with BPJ costs.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)

Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 28

Comment Excerpt:

C. Any Delay Caused by BPJ Determinations is Problematic Because of the Short BATW Applicability Date Range.

EPA has proposed that industry retrofit all necessary BATW treatment by no later than December 31, 2023. Proposed § 423.13(k)(1)(i). This latest applicability date is not realistic for reasons discussed in Section XXIV.C. and should be changed to December 31, 2025, to be consistent with the latest applicability date for FGD wastewater retrofits.

However, if EPA does not extend the date for completing BATW retrofits, it is even more problematic that EPA has called for BPJ determinations on BATW purge discharge limits. The multiple steps and analyses that regulators must perform in support of any BPJ determination is time-consuming and labor-intensive. The technology and economic reviews— even if the burden falls on the permittee to supply the essential information—will require coordination between the permittee and the permit writer, as data evaluation ensues. Once permit writers are satisfied with the amount and quality of the data, they must render a decision on which technology is most appropriate and what level of treatment it can achieve. They then must decide whether application of the technology is economically achievable for the permittees. Once that step is complete, they will need to develop proposed permit limits based on the assumed level of treatment and include within the proposed permit package justifications for each of their decisions.

All of this additional work will inevitably slow down the permitting process, which is extremely problematic because of the very limited amount of time the permittee has to design, procure, install, and optimize its BATW retrofit. If EPA finalizes a BPJ approach to regulating BATW purge, much of the time allotted for construction of the recirculating system may be consumed simply waiting for a final permit that will specify the BPJ limits that the technology must achieve.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 29

Comment Excerpt:

D. Permitting Authorities do not Favor BPJ Limits.

Imposing BPJ determinations on permitting authorities will be a significant burden. Permitting authorities generally disfavor BPJ determinations because they are so time-consuming and labor-intensive for permit writers.[26] Additionally, having to evaluate technologies and make judgments as to the economic achievability of a candidate technology requires time and resources that may not be available to permit writers.

In the 2013 draft ELG rule, EPA proposed BPJ limits for FGD wastewater under proposed regulatory options 3a (BPJ determinations for all FGD wastewater) and 3b (BPJ determinations for all FGD wastewater below 2000 MWs total wet scrubbed capacity). 78 Fed. Reg. 34,432, 34,458 (June 7, 2013). The Association of Clean Water Administrators ("ACWA") opposed these options and instead supported FGD wastewater options that set BAT limits. ACWA's opposition focused on the difficulty and inconsistency inherent in BPJ determinations:

State water program staff rely significantly on EPA to research and collect the necessary data to determine technology-based limits for various industrial groups. Most states lack the personnel and technical resources needed to undertake a BPJ analysis on a site-specific basis, including assessing performance of wastewater treatment technologies and developing cost estimates of various options….

Comment on Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-HQ-OW-2009-0819-4535 (Sept. 20, 2013) at 2. ACWA also commented that a "BPJ standard could lead to inconsistencies across states in a key industrial sector" and added "most states prefer a BAT standard." *Id.*

Echoing ACWA's concerns, the Michigan Department of Environmental Quality commented that "State water programs lack the personnel and resources to effectively research and develop proper Best Professional Judgment (BPJ) standards; relying on those state-specific BPJ standards for significant industrial categories can create inconsistencies between states and across regions." Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-HQ-OW-2009-0819-5510 (Sept. 20, 2013) at 1.

Missouri offered similar concerns, noting that BPJ determinations require specialized training and expertise: BPJ requires a high level of specialized training and places a significant strain on already limited staff time and limited resources available for training.

BPJ requires significant investigation into, and decisions based on, economic and financial factors. At this time, Missouri's most highly trained permit writers have limited background in economics. Missouri, like many other states, currently has little access to funding for advanced specialized training in engineering and economics.

BPJ requires permit writers to make a decision based on the information available, leaving the permits open to challenges from the facilities and possible third parties.

Missouri Dept. of Natural Resources, Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA HQ-OW-2009-0819-4383 (Sept. 19, 2013) at 2-3.

Choosing not to apply the BPJ option to BATW purge does not mean that states have no say in the regulation of BATW discharges. To the contrary, states must regulate any discharge that has a "reasonable potential" to exceed any water quality standards. States generally have a comprehensive set of water quality standards in place that they must review at least once every three years. See 33 U.S.C. § 1313(c). These water quality standards include requirements for metals such as mercury, arsenic and selenium, which are pollutants of concern for BATW. Also, to the extent that a permittee seeks a modification of its current BATW discharges, the permitting authority may request any data or information it deems appropriate before amending the permit

[26] EPA states that it "did not evaluate the incremental increase in the cost to state governments to evaluate and incorporate BPJ into NPDES permits" and solicits comments on "whether these incremental costs are significant enough to be included." 84 Fed. Reg. at 64,645. The costs of BPJ determinations for BATW purge are likely to be significant, although the permittee may carry a larger share of the burden than the permitting authority.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 30

Comment Excerpt:

E. For End-of-Life Discharges, BPJ Determinations Make Even Less Sense.

EPA also proposes to require BPJ determinations for "wastewater present in equipment when a facility is retired from service…." Proposed § 423.11(p); 84 Fed. Reg. at 64,630, n.15. As EPA notes, the amount of water remaining in a BATW system at the end of its life would be equivalent, at most, to the total "volume of a full system," which, assuming a 10 percent purge of the system volume each day, would be "the equivalent of 10 days." Id. at 64,630, n.14. EPA correctly concludes that discharge of the wastewater present in the system at the end of its useful life would be a "marginal, one-time increase in pollution." Id. For example, using our original hypothetical in Section II.A above with a total system volume of 300,000 gallons, we estimate that total toxic weighted pound equivalents ("TWPEs") [27] in that volume would be approximately 35 TWPES. Going through a BPJ determination for this *de minimis* discharge is not at all cost effective and wastes state resources. Instead, EPA should find that BAT for end-of-life discharges is equivalent to the existing BPT standards for TSS because, considering the low level of pollutants and the one-time nature of the discharge, it is obvious that no additional technological steps that could be used to minimize pollutants in the wastewater are economically justified.

[27] "TWPEs" stands for toxic-weighted pounds equivalent, which is a standard EPA metric that factors in the toxicity of pollutants by multiplying pollutant loadings of each pollutant by a pollutant specific toxic weighting factor.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 31

Comment Excerpt:

F. The Procedural and Technological Costs of Requiring BPJ Technologies for BATW Purge Make that Approach Economically Unachievable.

EPA acknowledges that it did not include in its economic impact assessment either the cost of the process that must be followed to select any further "BPJ" technologies for BATW or the cost of those potential technologies. 84 Fed. Reg. at 64,636, 64,654. The Agency asks for comment on whether and how it should consider both kinds of costs and whether failing to do so masks the true costs of the rule to regulators and the regulated community. Id.

EPA should consider both procedural and potential technology costs of its proposed BPJ approach. Indeed, because the rule creates the need for such decision-making and any ensuing technologies, EPA must consider those costs. Even if the Agency were not legally required to do so, it should consider them in order to develop a reasonably accurate picture of the economic impacts of its rule. Once it has fully considered those costs, EPA should conclude that the high recycle rate BATW system, operated in accordance with discharge conditions and BMPs like those UWAG describes above, is BAT for BATW.

The costs of BPJ decision-making are likely to be substantial because EPA's NPDES Rules, 40 C.F.R. §§ 125.3(c)(2), (d)(3), require the permit writer to decide what technology is the appropriate technology for category or class of point sources to which the permittee belongs, based on consideration of the same statutory factors that the statute requires EPA to consider when it establishes nationally applicable effluent limitations guidelines. The rules also require the permit writer to consider "[a]ny unique factors relating to the applicant." 40 C.F.R. § 125.3(c)(2)(ii). Although EPA's 2010 NPDES Permit Writers' Manual[28] identifies certain generic or otherwise publicly available sources of information a permit writer could consult, it is difficult to imagine a permit writer making a supportable BPJ determination without collecting (or, more likely, requiring the permittee to collect) information necessary to support consideration of all of the statutory factors.

EPA is in a better position than are UWAG members to fully assess the costs to regulators of making BPJ determinations, given that EPA regions issue NPDES permits in three states and for some federal and tribal facilities. UWAG has found no published information on the costs incurred by the regions in making such determinations.

For the permittee, costs can be substantial because they are likely to be the source of wastewater characterization, and the evaluation of the site-specific availability, performance, cost, economic impacts, and non-water quality and energy impacts of candidate technologies. A UWAG member reports that the company spent approximately $100,000 (in 2011 dollars) in connection with a BPJ determination for one of its facilities.

This member's experience is consistent with costs EPA has identified for studies required by other rules that require permittees to comprehensively evaluate the availability, performance, and costs of technologies. For example, as support for the information collection requirements imposed by its final rule for existing cooling water intake structures under CWA § 316(b), EPA estimated that the Comprehensive Technical Feasibility and Cost Evaluation Study the rule requires would take 1120 hours and cost over $72,000 (in 2011 dollars) per facility. *See* EPA, *Information Collection Requirements of the Cooling Water Intake Structures at Existing Facilities (Final Rule), Appendix A – Respondent Burden and Cost Analysis,* at 33 and Exhibit A.1c, EPA-HQ-OW-2008-0667-4156.[29] EPA estimated that permittees would spend 1220 hours and over $76,000 (in 2011 dollars) to evaluate non-water quality environmental and energy impacts. Id. Neither of those figures include the costs of developing and implementing wastewater sampling plans to characterize effluent variability for specific pollutants, conducting any physical studies that may be needed to evaluate the feasibility of technology options, or any costs for coordinating with the permit writer to define the scope of the study, participating in proceedings regarding its results or technology determinations based on those results, and any appeals. Those additional costs are likely to be even more substantial.

The cost and burden to permit writers also could be substantial. Again, the site-specific decision-making costs imposed by the § 316(b) rule provide a very rough proxy. When the of the estimated costs to the Director for making site-specific determinations are added together, the total comes to over $20,000 per facility for permitting authority. Although some of the individual cooling water intake studies requiring Director review are not relevant in setting BPJ technology-based requirements, EPA's rule makes it unnecessary for the Director to make threshold decisions about how to proceed and what information to require. That is not the case for BPJ technology-based requirements.

Perhaps the most significant cost imposed by BPJ decision-making is the cost of the uncertainty it introduces into an otherwise national rule. In a time of historic transition and enormous regulatory pressures, certainty and level playing fields are extremely important and introducing uncertainty can have substantial adverse economic, environmental, and grid reliability consequences.

[28] Exhibit 5-22 at 5-48.

[29] UWAG filed comments showing that EPA's estimates were, if anything, far too low. UWAG, Comments on Proposed Information Collection Request (ICR) Related to Cooling Water Intake Structures at "Existing" Facilities Under Clean Water Act § 316(b), EPA-HQ-OW-2008-0667-3162 (July 28, 2014) at 20-26. Real-world experience implementing the cooling water intake structure rule indicates that UWAG was correct. For example, EPA's estimated costs average out to about $62-$64 dollars per hour, while members report average costs of between $80-$130 per hour, with far more time needed for those studies.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 16

Comment Excerpt:

For example, the Proposed Rule requires permit writers to establish on a case-by-case basis using best professional judgement (BPJ) BAT limitations for the discharges from wet handling systems that will be permitted under the final rule. However, the development of such BPJ determinations by permitting authorities can require a time-consuming and resource-intensive process that is not necessarily synchronized with meeting the timelines in the Proposed ELG Rule, especially in light of the budgetary and manpower limitations on state permitting authorities that will need to be intimately involved in a highly site- and source-specific determination. In addition, in some cases permit writers have delayed drafting permit renewals for affected facilities pending EPA finalizing the ELG requirements. In addition, there might be questions as to whether electric companies in regulated states subject to state commission approval for capital expenditures may move forward with preparing for multi-million-dollar retrofits at a plant absent a clear regulatory requirement before project planning begins with associated cost expenditures. Obtaining a BPJ determination from the relevant state permitting authority can take a substantial amount of resources and time—EEI strategic partner the Tennessee Valley Authority (TVA) has seen a BPJ determination for one of its facilities take over one year to complete at an approximate cost of $100,000—and additional time may then be needed to install the appropriate technology necessary to comply with the BPJ limits ultimately established as part of that process.

FirstEnergy's Harrison Power Station is another example of the need to allow for extra time for the applicability date for BATW. Harrison is a three-unit, 1,984-megawatt (MW) plant in Haywood, West Virginia which has one-unit outage scheduled per year—unit outages are necessary for the installation of control technology, since often the unit must not be generating in order for control technology to be installed and tested for worker safety and other engineering reasons. Assuming any final requirements would not be finalized until mid-2020, the facility would have to complete detailed designs, permitting, financing, procurement, and ensure on time parts delivery for the installation of control technology to meet the new requirements in less than 12 months to meet the 2021 outage. If the 2021 outage is not met, the next outage is not scheduled until 2024, after the latest applicability date for BATW. Requiring Harrison to compress the installation schedule in such a manner could result in system impacts that are otherwise avoidable with appropriate time and scheduling, and EPA should factor these concerns in as part of whether it should extend the applicability date.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 12

Comment Excerpt:

E. Lack of BATW applicability date extension restricts compliance solutions.

By not extending the BATW applicability dates for compliance with ELG requirements, it may lead to unintended environmental degradation. In the 2019 proposal and as identified in this section, EPA justifies the lack of applicability date extension for BATW because many facilities have already started to install BATW compliance projects for CCR compliance. However, as also stated in item 3(A)(i) and 3(D) above, some companies have not moved forward with BATW compliance projects, rather choosing to wait until a final ELG Rule to know what compliance requirements would need to be met. This decision to wait, even though it was directed by EPA in 2017 Postponement Rule preamble, coupled with the lack of BATW applicability date extension has limited the compliance technology and solution options to those technologies that can only be implemented within the small applicability date timeframe of the 2019 proposal. This is especially true for multi-unit facilities that are required to strategically schedule their unit outages (See 3(B)(i) and (ii) above) to ensure grid reliability and meet electricity demand. This could lead to unintended environmental degradation as zero-liquid discharge technologies and compliance solutions likely could not be completed in the proposed applicability time frame. For example, when evaluating compliance options for the 2015 Rule, DTE evaluated a suite of technologies for BATW ELG compliance. One of the technologies was a completely zero liquid discharge, dry BA transport and management system. However, the preliminary timelines presented for completion of that technology and compliance option was over 4.5 years, largely due to the sequential, not simultaneous installation of the technology at a multi-unit facility. If BATW applicability dates do not get extended in the 2019 Rule, DTE will be forced to remove that compliance technology from its potential options. Other companies are certainly in the same situation and will likely need to choose from compliance options that can be installed within the shorter required time frame than was in the 2015 Rule. For the reasons presented, EPA should extend the BATW applicability dates.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 13

Comment Excerpt:

F. BPJ determinations on the proposed BATW purges are problematic for EPA's applicability dates.

In the 2019 proposal, EPA has proposed that high recycle rate systems for BATW be allowed a 10% total system volume purge averaged over 30 days. For that BATW purge, EPA recommends discharge limits be set by Best Professional Judgement (BPJ), a mechanism allowing for regulatory agencies to set discharge limits. Although a BPJ determination allows for a site-specific analysis, the comprehensive steps and analyses that regulators must perform for a BPJ determination can be very time intensive. This is problematic because the proposed applicability dates already restrict the time allotted for BATW retrofits, the BPJ process will only take more time away. If EPA finalizes a BPJ approach for the proposed BATW purge, then EPA should also extend the applicability date timeframes to allow for the BPJ process.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 13

Comment Excerpt:

TVA believes that EPA's proposal to develop BAT based on Best Professional Judgment (BPJ) for the allowed BATW purge, currently identified as 10% of the wetted volume, is ill advised. BPJ determinations of BAT limits are very resource-intensive for both the permittee and the permitting authority (typically states) and these would have to be replicated at each site (or unit) that is not retiring.

Leaving the allowable BATW purge ELGs to BPJ BAT hides the expected additional social costs and burdens that would be experienced by states in permitting these discharges. EPA states that the "proposed options would not change permit application requirements or the associated review . ... nor would the options change the efforts involved in developing or reviewing such permits." (Page 64668.) TVA disagrees. TVA reviewed Regulatory Option 2 found in the ERG memo and counted fifty-eight sites that had purges that would require BPJ determinations. Assuming the BPJ determinations costs approximately $100,000 (per site) based on TVA's previous experience[3], the total cost of preparing the BPJ analyses is approximately $5.8 M, or 13.8% of the purported cost savings being claimed by EPA due to the revision to high recycle BATW systems as BAT in the 2019 ELGs.

[3] Email from Tom Higgins (formerly of Ch2MHill now Advisian) indicating costs to do a BPJ determination in 2011 for Bull Run were approximately $100,000.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 14

Comment Excerpt:

EPA has also failed to account in its cost estimates the cost of installing additional, more costly BA TW purge wastewater treatment equipment that could be required once a BPJ determination is made. This "unaccounted for" cost to install additional equipment could lead to additional coal unit shutdowns beyond those EPA anticipated due to changes in the economic return of the unit.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 36

Comment Excerpt:

D. EPA Should Set BAT Limits on the BATW Purge.

EPA currently proposes that permitting authorities set "best professional judgment" ("BPJ") BAT limits for bottom ash purge water. This should not be required. Imposing site-specific BPJ determinations is an involved and complex approach. A BPJ determination is too time-consuming and burdensome, and not warranted for a small effluent stream. According to EPA regulations, the permit writer must consider numerous factors when setting BPJ-based BAT limitations and then select a model treatment technology and derive effluent limitations on the basis of the selected technology.[75] This imposes a significant burden to both the permitting authority and the permittee. States generally prefer that EPA set effluent limits on a national level because they rely heavily on EPA to research and collect the necessary data to set technology-based limits, including assessing performance of wastewater treatment technologies and developing cost estimates of various options.[76] States also continue to have significant resource constraints to perform these extensive activities that are more appropriately conducted by EPA.

BAT for the BATW purge clearly lends itself to the continuation of the previous Best Practicable Control Technology Currently Available ("BPT") limitations, especially for what amounts to a fraction of the previous BATW discharge. For example, Georgia Power's Plant Wansley has already installed RMDS that result in an approximate 96-98% reduction in BATW discharge when considered on a month-to-month basis. Subjecting the remaining 2-4% purge to BPT limitations is cost-effective, technically defensible and consistent with the Clean Water Act ("CWA") regulatory objective of making meaningful progress towards the elimination of discharges.

Therefore, Southern Company recommends that EPA eliminate the proposed BPJ standard for BATW purge and, instead, set BAT for BATW purge as the previous BPT limits applicable to this wastewater stream. This uniform standard, coupled with the BMP plan compliance option proposed herein, would force facilities to maximize recycling within these high-recycle-rate BATW systems. This proposed compliance option is well-reasoned and justified by the comparatively miniscule volume of wastewater that will be discharged from this treatment technology.

75 40 C.F.R. § 125.3(d).
76 Comment Letter from Shellie Chard-McClary, President, Ass'n of Clean Water Adm'rs, at 2 (Sept. 20, 2013) (Docket ID No. EPA-HQ-OW-2009-0819-4535).

Commenter Name: Ed Stone
Commenter Affiliation: Maryland Department of the Environment
Document Control Number: EPA-HQ-OW-2009-0819-8464-A2
Comment Excerpt Number: 1

Comment Excerpt:

For bottom ash transport water under the proposed rule, EPA requires the states to determine BAT for wastewater which is purged from high recycle rate systems (subject to the proposed 10% allowance). The Department believes that if EPA is proposing to replace the existing BAT requirements with new BAT requirements, then EPA should actually propose new BAT requirements using its superior resources to arrive at a scientifically and legally defensible national standard that also affords states a manageable level of flexibility. Importantly, for facilities with permits issued under the 2015 rule, the Department recommends the final rule not restrict States from using BPJ to establish "zero discharge" or any other technology as BAT for any allowed purges under a final rule (10% allowed under the 2019 Proposed Rule), if indeed BAT is to be determined on a site-specific basis.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 22

Comment Excerpt:

For similar reasons, EPA should not adopt the suggested alternative approaches of allowing permitting agencies to adjust the bottom ash purge rate upward or downward based on site-specific data, or allowing bottom ash purge discharges capped at a specific flow.[96] Because the record does not demonstrate that any purge discharges should be permitted, *a fortiori*, it does not demonstrate that site-specific or flow-based discharges should be permitted. Further, state permitting agencies often lack sufficient resources to evaluate the performance of treatment technologies on a site-specific basis, and permitting agencies are subject to non-technical pressures that make them unlikely in most circumstances to set more stringent effluent limitations than plant operators themselves propose.[97] Accordingly, EPA must also reject its suggested alternative approaches to permitting bottom ash purge discharges.

[96] See 84 Fed. Reg. at 64,636.
[97] See Sahu Expert Report at 14-15.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 8

Comment Excerpt:

<u>EPA Should Consider BAT limits for Bottom Ash Transport Water Purge</u>

Duke Energy believes EPA should establish BAT limits for the discharge of BA transport water based on the operation of retention basins with pH adjustments and sedimentation. Requiring permitting authorities to develop BAT based on Best Professional Judgment (BPJ) is a very resource-intensive process for both the permittee and the permitting authority (typically states) that would need to be replicated at each site or unit. The BPJ process on an individual permittee basis should closely resemble the same process EPA performs on a national basis to develop BAT for the effluent limitation guidelines. This is an exhaustive process. Ideally, at least a year's worth of data would be collected from the high recycle BA transport water system after its installation to ascertain the site-specific loadings necessary to determine BPJ. Additionally, treatment technology assessments including cost, feasibility and performance, and statistical analysis to develop permit limits would need to be completed. Then a BPJ evaluation can be conducted considering, at a minimum, the following:[13]

- Age of equipment and facilities involved,
- Process employed,
- Engineering aspects of the application of various types of control techniques,
- Process changes,
- Cost of achieving such effluent reduction,
- Non-water quality environmental impact (including energy requirements), and
- Any unique factors relating to the applicant.

13 Clean Water Act section 402(1)(a)(1) and 40 CFR 125.3(c)(2), 40 CFR 125.3(d)(3)

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 15

Comment Excerpt:

B. EPA Should Consider Setting BAT Based on BMP Plans for High Recycle Rate BA Transport Water Systems

EPA proposes to set new BAT limits and PSES on the volume of BA transport water that can be discharged based on higher recycle rate systems. [33] The Association supports the BA transport water purge of 10 percent by volume. EPA proposes to set BPT limits for bottom ash purge maintenance water that are equal to those set in the 2015 rule for FGD wastewater, combustion residual leachate, gasification wastewater, and flue gas mercury control wastewater. Those limits are also the same TSS and oil and grease BPT limits as applied to low volume wastes.[34] State permit writers would be responsible for setting BAT limits based on best professional judgement (BPJ). APPA recommends that EPA set BPJ based on BMP plans.

1. A BPJ Determination is Problematic

A BPJ determination is a multi-step evaluation that requires permit writers to consider factors such as the age of the equipment and facilities involved, the process, process changes, engineering aspects of the application of various types of control techniques, non-water quality environment impacts, and the cost of achieving the effluent reduction. Setting BPJ limits for purge water would create uncertainty for the industry. The industry is moving to install remote drag train systems (RMDS) and dewatering bins, which remove most pollutants. Therefore, it is even more uncertain what types of steps or equipment might be employed to remove additional pollutants. Utilities would likely have to evaluate potential technologies and provide justification as to why certain technologies are economical or not. Further, there is no clear guidance for the permittee documentation for BPJ limits. Each permitting authority would be free to determine the level of documentation needed. In addition, permitting authorities do not seem to favor BPJ limits. Comments submitted by the Association of Clean Water Administrators opposed BPJ limits for FGD wastewater under the proposed 2013 ELG rule.[35] ACWA's comments focused on the difficulty and inconsistency inherent in BPJ determinations.[36]

States can still provide input regarding the regulations of BA transport water discharges. States must regulate any discharge that has a "reasonable potential" to exceed any water quality standard, and states generally have a comprehensive set of water quality standards in place, including ones for metals such as mercury, arsenic, and selenium, which are pollutants of concern for BA transport water. Also, to the extent that a permittee seeks a modification of its current BA transport water discharges, the permitting authority may request any data or information it deems appropriate before amending the permit.

33 84 Fed. Reg. at 64,630.
34 Proposed § 423.12(b)(11); 40 C.F.R. § 423.12(b)(3).
35 78 Fed. Reg.34,432, 34,458 (June 7, 2013).
36 EPA-HQ-OW-2009-0819-4535 (Sept. 20, 2013) at 2.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 14

Comment Excerpt:

Therefore, EPA should not allow any purge of recycled BATW. Going further, EPA has solicited comment on even more flexibility, as follows:

The EPA solicits comment on an alternate approach that establishes a standard purge rate of 10 percent that can be adjusted upward or downward based on site-specific operating data. Finally, the EPA solicits comment on whether these discharges should be capped at a specific flow. The EPA requests commenters identify and include available data or information to support their recommended approach.[43]

Based on my experience working on ELG matters for the last 5 years with numerous state permitting agencies, this is a bad idea. Permitting authorities will likely approve higher purge rates based upon little technical support or evidence of need provided by operators. In my experience, best professional judgement is rarely exercised and plant data are often uncritically accepted by agencies. Leaving it to the individual permitting agencies that are often resource constrained and subject to many non-technical pressures, will lead to further widening of EPA's already generous loophole.

43 84 Fed. Reg. at 64,636. In addition, in the TDD, Section 8.4 EPA states: "This proposed rule includes BAT effluent limitations and standards on any wastewater purged from a high recycle rate system established by the permitting authority on a case-by-case basis using BPJ." TDD at 8-24.

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 10

Comment Excerpt:

Along the same lines, the permitting authority will also need to determine control measures for any purge water discharged, whether from a tank-based system or otherwise. EPA has indicated, and Cleco agrees, that these control measures should be left to the permitting authority's Best Professional Judgment ("BPJ").[57] As EPA has also recognized, the permitting authority will consider "site-specific treatment technologies already installed" as part of its BPJ determination.[58] Those technologies will be impoundments in many cases. And even where impoundments have not already been integrated into the closed-loop system, the permitting authority might well select them as the basis for BPJ due to the high cost of other options.

[57] See id. at 64,636.
[58] Id.

Commenter Name: Eric C. Massey
Commenter Affiliation: Arizona Public Service Company
Document Control Number: EPA-HQ-OW-2009-0819-8324-A1
Comment Excerpt Number: 8

Comment Excerpt:

IV. BAT Limits for the Ultimate Discharge of BATW Recirculation System Purge Water Should be Based Upon Water Recycling BMPs Rather than Permit-Writer BPJ.

APS agrees with and strongly supports the UWAG's proposal to use BMPs in lieu of BPJ to establish BAT limits on the 10% BATW purge water discharges associated with BATW recirculation systems. Adding a requirement for permittees to perform a one-year BMP study under Proposed §423.13(k) would serve a number of important functions: (1) Allowing permittees to perform real-time evaluations of BATW system performance to identify workable bases for water recycling improvements, which can be made enforceable permit conditions through subsequent NPDES proceedings; (2) Prevents unnecessary permitting delays from complicated and cumbersome BPJ evaluations of power plant BATW recirculation systems, especially given that EPA has proposed maintaining the current outside date for imposing BATW recirculation system implementation, December 31, 2023[20]; and (3) Recognizing that power plant BATW recirculation systems varying so much across the electric utility industry that setting specific "numeric effluent limitations [is] infeasible".[21] As documented by EPA throughout its recent ELG rulemakings, "high recycle" BATW recirculation systems are extremely effective at removing pollutants, such as dissolved metals, and that additional low-volume waste treatment for purge discharges (per BPT) provide an extra layer of pollution control[22]; as such, there should be no need for an additional, complicated, and highly-resource intensive BPJ evaluation to set *another* level of control. BMPs—which are critically evaluated based upon real-time BATW water recirculation power plant data and implemented in a manner to maximize facility water recycling—should provide all the controls that are necessary to ensure the protection of aquatic environments consistent with BAT.

[20] S*ee,* Proposed § 423.13(k)(1)(i)
[21] S*ee,* 40 C.F.R. § 122.44(k)(1), (3)
[22] S*ee e.g.*, 84 Fed. Reg. at 64,636 (November 22, 2019)

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 48

Comment Excerpt:

3. EPA's Proposal Is Unrealistic

Rather than employing a BAT standard, EPA proposes that effluent limitations for purged wastewater be established by permitting agencies on a case-by-case basis using best professional judgment (BPJ). This is unjustified and a mistake: a nationwide standard, zero discharge, is already in place, based on readily available technology already operating in the field. EPA lacks the authority to abandon the current nationwide standard under these circumstances.

Moreover, agencies refuse all too often to apply best professional judgment to set technology-based limits. For example, in Tennessee, TDEC has repeatedly refused to set effluent limits using BPJ, forcing conservation groups to file suit.[120] Indeed, EPA has previously acknowledged that BPJ is not appropriate where:

there are sufficient data to set uniform, nationally applicable limitations on . . . wastewater at plants across the nation. Given this, BPJ permitting of FGD wastewater would place an unnecessary burden on permitting authorities, including state and local agencies, to conduct a complex technical analysis that they may not have the resources or expertise to complete. BPJ permitting of FGD wastewater would also unnecessarily burden the regulated industry because of associated delays and uncertainty with respect to permits.[121]

These same principles, which EPA articulated in the 2015 rulemaking regarding FGD wastewater, apply equally to bottom ash transport water—EPA should maintain the current, uniform limits.

[120] See *Tenn. Clean Water Network v. Tenn. Bd. of Water Quality, Oil, & Gas*, No. 13-1742-I, 5–12 (Tenn. Ch. Ct. Jan 28, 2015) (reviewing conservation groups' efforts and TDEC's refusal to set limits via BPJ) (Attachment 44); Letter from Vojin Janjić, Tenn. Dep't of Env't & Conservation, to Terence Edward Cheek, TVA (July 1, 2018) (failing to set limits using BPJ) (Attachment 45).
[121] 80 Fed. Reg. 67,837, 67,852.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 34

Comment Excerpt:

2. End-of Life Discharges from High Recycle Rate Systems

EPA proposes to require BPJ determinations for "wastewater present in equipment when a facility is retired from service…"[37] APPA recommends EPA set BAT for this de minimis discharge equivalent to the existing BPT standards. EPA concludes that discharges of wastewater present in the system at the end of its useful life would be a "marginal, one-time increase in pollution."[38]

37 Proposed 423.11.(p); Fed. Reg. at 64630, n 15.
38 84 Fed. Reg at 64630, n 14

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 3

Comment Excerpt:

With respect to the purge stream itself, NRECA recommends EPA require permittees to develop a "best management practices plan" to maximize the recycling of BATW based on the defined model technology for either mechanical drag chain or dewatering bin systems.

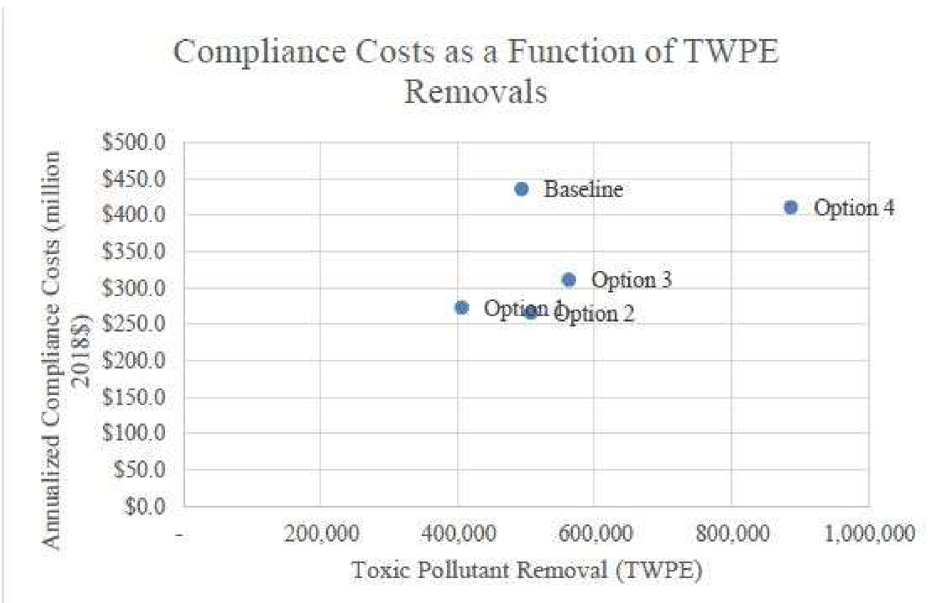
5 Regulatory Options – Compliance Cost Methodology

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 43

Comment Excerpt:

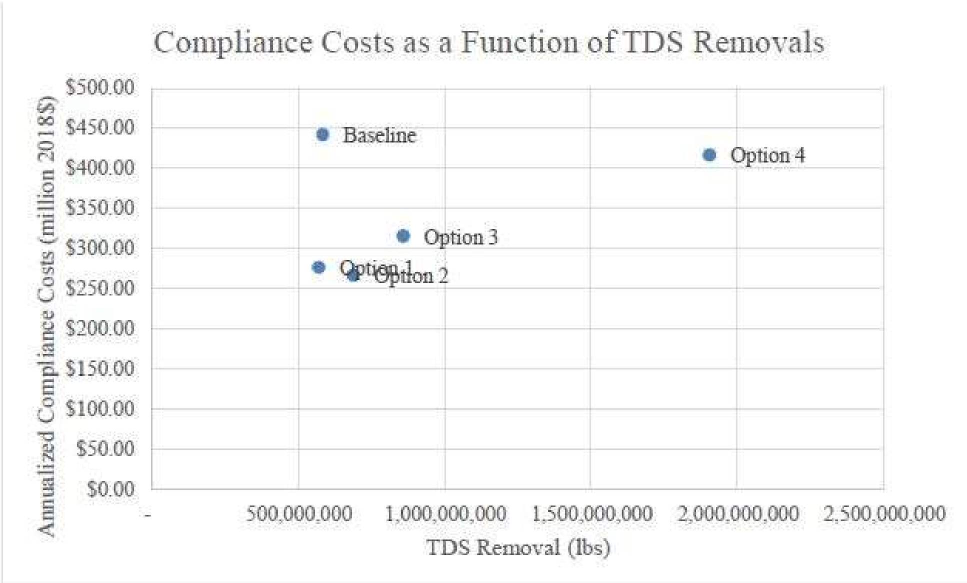
XI. The Proposed Rule's Overall Pollutant Reductions Compare Favorably to Those of the 2015 Rule.

When comparing the overall impact of the Proposed Rule to the 2015 rule, the pollutant reductions are very similar. EPA provides the following graph, which compares all options according to costs and toxic pollutant removals:[54]



Based on a comparison of total TWPEs, Option 2 (BATW with purge, plus the low utilization boiler exemption) removes slightly more TWPEs than the Baseline option (which is defined as implementation of the 2015 rule). EPA estimates that the Baseline case would remove 492,698 TWPEs per year, while Option 2 would remove 506,417 TWPEs per year.[55] Not only does Option 2 remove more TWPEs, it does so, according to EPA, at a much reduced cost. In short, according to EPA, the proposal would produce more toxic pollutant reductions than the 2015 rule and at a lower cost.

Notably, EPA also found that Option 2 also removes slightly more total dissolved solids ("TDSs")[56] than the Baseline (2015 rule).[57]



Because the Baseline and Option 2 remove similar amounts of TDSs, the dissolved fractions of pollutants of concern—taken as a whole—would be addressed under the Proposed Rule ***to a similar degree as they were addressed under the 2015 rule,*** according to EPA's analysis.

[54] EPA, Cost-effectiveness Calculations, Inputs, and Outputs, Attachment 1 – Cost-effective Calculation, EPA-HQ-OW-2009-0819-7699-ATT1 (Oct. 23, 2019) ("EPA, EPA-HQ-OW-2009-0819- 7699-ATT1").
[55] EPA, EPA-HQ-OW-2009-0819-7699-ATT1.
[56] While EPA found that the Baseline case removed more TSSs than Option 2, the unremoved TSS must not contain a significant amount of toxics, or the TWPE removal for Option 2 would not be as favorable relative to the Baseline.
[57] EPA, EPA-HQ-OW-2009-0819-7699-ATT1.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 1

Comment Excerpt:

Purestream provides mobile wastewater treatment systems for floatation-filtration (IGF+), distillation and brine concentration (AVARA) and thermal evaporation (FLASH). Purestream also provides brine management and encapsulation services. All Purestream technologies are commercially proven at full scale and available to our clients with a no-risk, firm-price agreement, including brine management/encapsulation. The integration of proven, reliable wastewater technologies with the BOOM business model addresses the challenges of today's steam electric generating stations. The following comments are offered to correct and/or supplement the bases for the Proposed Rule.

1. The EPA's technology discussion and economics model overlook the BOOM business model and result in a conclusion that power plants with unknown remaining lives cannot afford wastewater treatment. Using the BOOM approach, any power plant can commission and decommission wastewater treatment whenever and for however long it's needed.

- **BOOM services are available on demand.** If a power plant owner has made appropriate contract arrangements, they can obtain service within 2 weeks of a request or they can have Purestream equipment standing by at their power plant site. Purestream dispatches labor for operations and maintenance, Purestream provides spare parts and consumables, and Purestream bills at a fixed price per gallon for all gallons processed until service is no longer needed. The equipment remains the property of Purestream, it is removed when no longer needed, and it can then be redeployed.
- **BOOM services are not uncommon at power plants.** Many power plant owners rely on the BOOM business model for CCR handling and disposal, boiler chemical cleaning, air heater washing, vacuum truck services, coal yard operations, and more.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 3

Comment Excerpt:

1. The EPA's technology discussion and economics model overlook the BOOM business model and result in a conclusion that power plants with unknown remaining lives cannot afford wastewater treatment. Using the BOOM approach, any power plant can commission and decommission wastewater treatment whenever and for however long it's needed.

- **For Bottom Ash Transport Water (BATW),** a plant operator/owner can request services with AVARA to concentrate contaminants into brine and return approximately 98% of the wastewater for reuse as BATW or with FLASH to concentrate brine and evaporate approximately 98% of the wastewater as clean steam. In both cases, the concentrated brine can be encapsulated with some combination of fly ash, Portland cement and/or lime. Alternatively, IGF+ may be employed if traditional physical-chemical treatment is adequate.
- **For FGD blowdown,** a plant operator/owner can request services with AVARA to concentrate contaminants into brine and return about 95% of the wastewater for reuse as FGD makeup or with FLASH to concentrate brine and evaporate about 95% of the wastewater as clean steam. In both cases, the concentrated brine can be encapsulated with some combination of fly ash, Portland cement and/or lime.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 4

Comment Excerpt:

2. Without considering technology advancements or cost reductions that have occurred since the 2016 Rule, the EPA made a broad generalization that thermal processes are inherently "too expensive" for power plants.

a. Since 2016, the industry has gained experience with full-scale thermal systems. Purestream and other providers of thermal technologies have conducted more pilot-scale and full-scale demonstrations on FGD wastewater to provide data, know-how and experience resulting in increased confidence in thermal technologies. In the present draft ELGs, the EPA has not considered the technology readiness level of thermal technologies compared to advanced membrane filtration, HRTR and LRTR.

b. Purestream has effectively reduced the cost of its ZLD system by pre-treatment with conventional reverse osmosis which preconcentrates FGD purge or BATW prior to thermal treatment. Reverse osmosis followed by AVARA technology can return over 90% of FGD purge as very clean water for reuse in the power plant. When coupled with Purestream's FLASH technology, reverse osmosis returns clean water for reuse and FLASH evaporates most of the concentrate from the reverse osmosis. Combining thermal treatment with membranes also minimizes the quantity of brine that must be encapsulated and therefore the amount of fly ash required.

Following is a comparison of four 200 GPM treatment systems – (1) AVARA (thermal) alone, (2) AVARA in combination with ultrafiltration and reverse osmosis, (3) FLASH (thermal) and (4) FLASH in combination with ultrafiltration and reverse osmosis.

Summary of Pricing	
Purestream Brine Concentration Treatment System	All-in Equipment, Labor, Energy and Chemical per Gallon Price
AVARA	As low as $0.06
AVARA with Membrane Pre-treatment	As low as $0.03
FLASH	As low as $0.065
FLASH with Membrane Pre-treatment	As low as $0.045

Prices shown may vary for FGD purge based on its chemical composition. Prices shown are typical for BATW and low-volume wastewater.

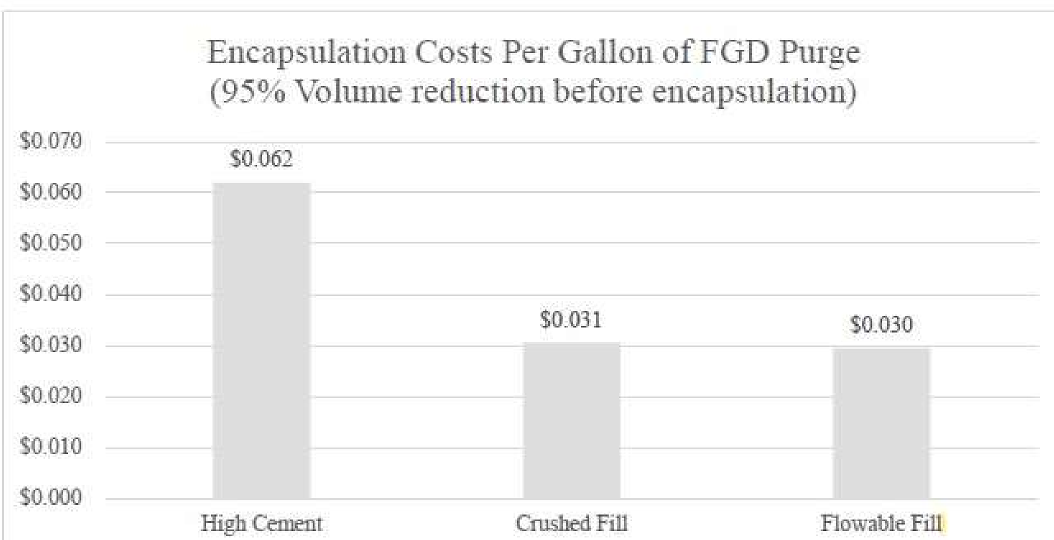
"All-in" price is the full cost of wastewater treatment. Brine encapsulation is an added cost of about $0.03 per gallon of wastewater treated.

c. The EPA analyses has misplaced confidence in technology advancements and price reductions for advanced membrane and paste technologies and failed to consider current and future technology advancements for thermal technologies, so the BAT analyses are biased against thermal processes.

d. Encapsulation know-how has also progressed since 2016. At that time, Purestream relied on cement as the bulk material to encapsulate brine to meet TCLP and paint filter test goals for landfilling. Sine that time, Purestream has advanced the technology by developing lower-cost grout mixes that can be beneficially used rather than disposed and reduced the cement requirement, all resulting in decreased cost for thermal ZLD.

The following plot shows encapsulation cost per gallon of FGD purge as the technology advanced from a "High Cement" mix for disposal in a landfill to "Crushed Fill" and "Flowable Fill" that can be beneficially used for pond closure, landfill development/operation, and other power plant construction projects. Grout mixes that are beneficially used can be produced for half the cost of the "High Cement" grout for disposal.

And, beneficially using grout saves money on the materials is replaces. No credit has been included for those savings.



Commenter Name: Major L. Clark, III and David Rostker
Commenter Affiliation: Office of Advocacy, U. S. Small Business Administration
Document Control Number: EPA-HQ-OW-2009-0819-8310-A1
Comment Excerpt Number: 1

Comment Excerpt:

EPA should be evaluating cost-effectiveness of ELGs consistently.

Overall, Advocacy believes that EPA should be more cognizant of the cost-effectiveness of its proposed requirements and consider the cost-effectiveness on a unit-by-unit basis rather than based on industry averages. As Advocacy wrote in its 2017 petition:

EPA historically has measured the environmental benefits of ELG rules in terms of the quantities and relative toxicities of the pollutants to be removed, known as toxicweighted pound equivalents (TWPEs). The TWPE metric is used to measure the benefits of pollutant removals to the public. The agency has used this metric over several decades in determining whether the rule is achieving cost-effective pollutant reductions. ELGs typically cost less than $100/TWPE [in dollars inflation-adjusted back to 1981]. Rules well in excess of this benchmark were determined to be not cost-effective and not Best Available Technology (BAT).[10] [Footnotes omitted]

Based on calculations available in the record, [11] it appears the EPA's proposal still would require the adoption of control technologies that are not cost-effective. This kind of requirement is especially harmful to the small entities operating coal-fired power plants. This segment of the electricity market has been declining over the last decade, a result of market forces (i.e., the decline in the price of natural gas and financial incentives for investments in renewables) and environmental regulations (i.e., the Mercury and Air Toxics rule, rules on coal combustion residue, and state-level greenhouse gas initiatives) that have decreased the competitiveness of coal when compared to natural gas and renewables.[12] As a result, utilization rates have been falling, and units that were once providing constant power to the grid are now called upon to provide power at peak demand or respond to the reliability needs of the electricity grid. With decreased utilization also comes a smaller environmental footprint. EPA should therefore avoid requirements that impose additional burden on these lesser utilized units without a case-by-case evaluation of whether it will result in the expected magnitude of environmental benefits.

[9] SBA Petition for Reconsideration of EPA's Steam Electric ELGs – DCN SE06611, (April 5, 2017) available at regulations.gov, Document ID EPA-HQ-OW-2009-0819-6481.
[10] Id. at 6-7.
[11] See American Public Power Association public comments on Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (January 21, 2020), at Appendix, available at regulations.gov Docket ID EPA-HQ-OW-2009-0819..
[12] See ERG (Eastern Research Group, Inc.), Memorandum re: Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule – DCN SE07207, July 31, 2019, at Table 5, available at regulations.gov Document ID EPA-HQ-OW-2009-0819-7373.

Commenter Name: Angie Rosser
Commenter Affiliation: West Virginia Rivers Coalition (WV Rivers), et al.

Document Control Number: EPA-HQ-OW-2009-0819-8321-A1
Comment Excerpt Number: 1

Comment Excerpt:

The Environmental Protection Agency (EPA) states that this proposal would save approximately $300 million dollars annually, however, this figure does not take into account the costs to restore polluted rivers and streams that would result from the proposed changes.

6 Regulatory Option – Pollutant Loadings Methodology

No comment excerpts were received on this topic.

7 Industry Profile and Plant Operations

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 16

Comment Excerpt:

EPA Incorrectly Assumed that Some Units Have Technologies That the Units Do Not Have

EPA's Economic Impact Analysis—one of the lynchpins of its Regulatory Impact Analysis—assumed that certain units had ELG compliant technologies and, therefore, did not factor in any compliance costs. In the analysis ERG completed for EPA they assumed some facilities would not incur costs to comply with the Proposal's BATW requirements based on faulty assumptions about existing technology at those facilities. For example, Talen's H.A. Wagner Unit 3 has a partial BATW recycle treatment system that would need upgrades to meet the proposed BATW requirements. But EPA assumed no costs for this unit. Talen's Montour plant continues to rely on a surface impoundment in its BATW treatment system that has a direct discharge, but EPA erroneously assumed it "converted to a closed loop or dry system in 2018" and, therefore, it would not incur costs. EPA's Economic Impact Analysis should be updated to reflect the significant compliance costs they inappropriately excluded in their analysis.

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper

Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 13

Comment Excerpt:

Santee Cooper has recently announced preliminary plans to retire the four coal-fired units at this facility. The target retirement dates are 2023 for Winyah Units 3 and 4, and 2027 for Winyah Units 1 and 2.

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 1

Comment Excerpt:

1. Statement of Interest

CE is a public electric and natural gas utility located in the Midcontinent Independent System Operator (MISO) footprint, serving over 1.8 million residential, commercial, and industrial customers. It is one of the two largest public utilities in the lower peninsula of Michigan. The NOPR impacts CE because it owns and operates five coal-fired units generating bottom ash transport water. Two of the five units will be retired before 2028. Under the proposed rule, the remaining three units will require retrofit of their bottom ash transport water systems to achieve the proposed high recycle rate. Thus, CE has a significant interest in the outcome of this NOPR, and CE's interests will not be adequately represented by any other party.

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 4

Comment Excerpt:

CE plans to retire its D.E. Karn (Karn) Units 1 and 2, both of which are coal-fired, in 2023. This plan has been approved in our recent Integrated Resource Plan (IRP) filing with the Michigan Public Service Commission (MPSC) and has received MISO's approval to suspend Karn Units 1 and 2 operations without the need for the units to be designated as a System Support Resource (SSR).

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 9

Comment Excerpt:

At CE's J.H. Campbell site, Units 1 and 2 are scheduled to shut down in 2031, nearly a decade before Unit 3's retirement in 2040.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 13

Comment Excerpt:

In addition, in Spring 2019, the City of Lakeland announced the closure of its 365 MW coal-fired plant referred to as C D McIntosh Unit 3 by the Fall of 2024.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 3

Comment Excerpt:

Talen strongly agrees the Retirement Subcategory should include repowered units, such as will be the case by 2028 for Talen's Brunner Island facility in York Haven, PA. Talen added natural gas capability to our 3 coal fired boilers and has plans to fire only natural gas in these boilers (considered to be repowered) by the end of 2028.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 6

Comment Excerpt:

Specifically, at Talen's three units at its Brunner Island facility, which since 2017 can operate on both natural gas and coal, it reached an agreement with the Sierra Club in 2018 to phase out the coal operations by the end of 2028. This phase out includes an interim reduction in coal firing starting in 2023 where the plant will not operate on coal during the ozone season (May through September).

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 11

Comment Excerpt:

Talen is considering the option of repowering its Montour plant located near Washingtonville, PA given its success in repowering its Brunner Island plant discussed above. Montour is working on the various approvals and permits as it considers this investment but has yet to make its final decision because of market and regulatory uncertainties. https://www.dailyitem.com/news/local_news/talen-delays-montour-plant-gas-conversion/article_3153990b-e573-5238-b176-32b95c6a94f6.html.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 29

Comment Excerpt:

[4] Many utilities including TVA will no longer utilize impoundments to handle CCRs. Bull Run, Kingston, Cumberland, Shawnee, all have or will have composite lined process water basins. Gallatin's flows will be managed in an interim tank based system. Paradise Unit 3 is retiring.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 27

Comment Excerpt:

Coal Fleet Announcements Below is a summary of announced closures of more than 121,000 MW of coal-fired generation capacity (35% of the 339 GW of total coal-fired generation capacity in 2010) that will be retired or repowered between 2010 and 2025.[1, 2]

01/21/20

Coal Fleet Announcements

Below is a summary of announced closures of more than 121,000 MW of coal-fired generation capacity (35% of the 339 GW of total coal-fired generation capacity in 2010) that will be retired or repowered between 2010 and 2025.[1, 2]

Company	Total MW	State	Year(s) Built	Year(s) Will Retire	Units Retiring/Notes
AEP	11,256	various	1944-1986	2011-2020	35 units in 7 states (converting some to NG)
AES	4,521	various	1948-1987	2011-2018	21 units in 4 states (converting some to NG)
Allete	490	MN	1953-1960	2015-2018	7 units
Alliant	1,962	IA, WI	1921-1969	2010-2018	27 units (converting some to natural gas)
Ameren	1,277	MO, IL	1953-1961	2011, 2022	7 units
APS	633	AZ	1963, 1964	2015	3 units
Berkshire	1,891	various	1925-1983	2014-2017	14 units in 4 states (converting 4 to NG)
Black Hills	124	various	1948-1969	2012-2014	7 units (CO, WY, SD)
Consumers	1,485	MI	1952-1961	2015-2023	9 units
Dominion	3,095	MA, VA	1952-1992	2012-2023	20 units
DTE	2,598	MI, WI, CA	1952-1989	2010-2023	14 units (converted 1 to biomass)
Duke	10,021	various	1940-1978	2011-2024	59 units in 5 states (converting some to NG)
Edison Int'l	868	IL	1955-1968	2010-2018	3 units
Empire District	305	KS, MO	1950-1986	2013-2020	4 units
Evergy	1,333	KS, MO	1955-1969	2015-2019	10 units
Exelon	895	PA	1954, 1960	2011-2012	3 units
FirstEnergy	11,930	various	1944-1980	2010-2022	41 units (MD, OH, PA, WV)
Madison G&E	178	WI	1938-1961	2010-2012	5 units
NextEra	1,832	FL	1987-1995	2017-2018	4 units
NiSource	3,053	IN	1950-1986	2010-2023	12 units
NRG	7,037	various	1949-1970	2010-2017	42 units in 8 states (converting 1 to NG)
OG&E	990	OK	1977-1978	2018	2 units (converting to natural gas)
PGE	601	OR	1980	2020	Will retire Boardman plant 20 years early
PNM	1,684	NM	1973-1982	2017-2022	4 units
PPL	1,062	KY, MT	1953-1969	2015	7 units
PSEG	1,252	NJ	1960-1968	2017	3 units
Puget Sound	614	MT	1975	2022	2 units
SCANA	650	SC	1953, '58, '62	2012-2018	6 units
Southern	9,853	various	1949-1973	2011-2019	38 units in 4 states (converting some to NG)
TransAlta	1,460	WA	1971	2019-2024	2 units (Centralia)
Tucson Electric	173	AZ	1958	2015	1 unit (converting to natural gas)
TVA	9,754	TN, AL, KY	1952-1970	2012-2023	35 units
Vectren	580	IN	1979-1986	2023	3 units
Vistra	10,547	IL, MA, TX	1953-2009	2011-2022	27 units
WE Energies	1,873	WI, MI	1968-1985	2015-2020	9 units (converting 2 to natural gas)
WPS	247	WI	1949-1960	2015	4 units
Xcel Energy	2,090	CO, MN	1951-1975	2010-2025	14 units
Others	11,420	various	1925-2009	2010-2024	
	121,631				

[1] Closures are taking place for a variety of reasons, including plant age, fuel prices, decreased demand, consent decrees and the settlement of EPA complaints, the cost of complying with environmental regulations, etc. Because

some plant closure details and/or plans for replacement generation have not been finalized, it is not possible to determine the exact number of closures, the mix and quantity of generation replacing the retiring coal units, or the exact amount of emissions reductions.
[2] To the degree that retired coal plants are replaced or repowered with natural gas generation, mercury and SO2 emissions will be virtually eliminated and CO2 emissions reduced by almost half at those units.

Commenter Name: Jeffrey L. West
Commenter Affiliation: Xcel Energy Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8294-A1
Comment Excerpt Number: 1

Comment Excerpt:

EPA's proposal to subcategorize the BAT limitations for boilers retiring by 12/31/2028 is appropriate - As we transition to cleaner energy, we will be transitioning from the use of coal fired generation. As discussed above, Xcel Energy currently operates three coal-fired units that are impacted by the changes identified in this proposed rule. These three coal-fired units are scheduled to retire prior to 12/31/2028.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 123

Comment Excerpt:

Similarly, EPA assumed that a number of plants already have installed chemical precipitation and, in some cases, biological treatment capable of achieving the proposed FGD wastewater limits. For example, Oak Creek Power Plant (Units 5-8) sends its FGD wastewater to Elm Road Generating Station for treatment in a chemical precipitation treatment system. The treatment system does not have a low residence time biological treatment system that would be required to comply with the proposed FGD wastewater limits. It is unclear whether EPA included the Oak Creek Power Plant flows when sizing the equipment and deriving cost estimates for Elm Road Generating Station to comply with the proposed FGD wastewater requirements. It is clear, however that EPA erroneously assumed that the Oak Creek Power Plant would not incur any additional costs to retrofit or install new FGD wastewater technology. Id. Again, there may be other examples not listed here.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois

Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 2

Comment Excerpt:

CWLP currently operates four coal-combustion units that utilize Illinois coal; three of these were placed into service in 1968, 1972 and 1978 (Units 31, 32 and 33, respectively), and a fourth, Dallman Unit 4, went online in late 2009. Dallman Unit 4, as one of the newest coalfired units in the nation, was constructed with a dry ash handling system, closed-cycle cooling and some of the most advanced air pollution controls of any power plant in the country including low NOx burners, selective catalytic reduction ("SCR"), hydrated lime injection, baghouse, wet flue gas desulfurization (WFGD), and a wet electrostatic precipitator ("ESP"). Included in the design of Unit 4 was a WFGD scrubber system that was designed to be compatible with and have its WFGD scrubber wastewater co-mingled and treated along-side the three older Dallman units which also have WFGD systems. The combined wastewater from the WFGD scrubbers for these four units today is approximately 250,000 gallons per day. WFGD wastewater from all four units is sent to a pretreatment plant on-site and following physical/chemical treatment is sent via dedicated forced main through the sewer system to the local Publically Owned Treatment Works (POTW), operated by the Sangamon County Water Reclamation District ("SCWRD"). On-site treatment consists of an equalization tank and clarifier with the addition of lime, organosulfide chemical, ferric chloride and cationic and anionic polymers to achieve chemical precipitation. In addition to the capital investment of over $15 million a decade ago for this pretreatment system, CWLP spends over $1.75 million per year to operate the system (including annual fees of $1.5 million to SCWRD to accept the WFGD waste stream).

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 1

Comment Excerpt:

Merrimack Station's National Pollutant Discharge Elimination System ("NPDES") permit renewal application is currently pending before EPA Region 1. As part of that pending application, Merrimack Station is currently opted into the Voluntary Incentives Program for FGD wastewater in the existing regulations, and the application is being processed on that basis. Our comments on the Proposed Rule are informed by, and relevant to, the issues presented in that pending permit application.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)

Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 122

Comment Excerpt:

E. EPA Incorrectly Assumed that Some Units Have Technologies That the Units Do Not Have.

A review of EPA's industry profile indicates that the Agency assumed that some facilities have in place or will have in place by December 31, 2028, technologies that they do not in fact possess. See EPA, 2028 Unit-Level Industry Profile, EPA-HQ-OW-2009-0819-7707; ERG, *ERG Review of Potential Closed-Loop Bottom Ash Transport Water Systems,* EPA-HQ-OW2009-0819-7148 (Feb. 23, 2018) ("ERG, 2018 BATW Review").

For example, EPA's consultant recommended that five plants be excluded from cost analysis because, while they were listed as "no recycle" plants, ERG speculated that they likely had begun to recycle at some point since 2010. ERG, 2018 BATW Review at 2. Of the five, however, UWAG has verified that none currently recycle any bottom ash transport water.

In many cases, EPA also assumed facilities would not incur costs to comply with the Proposal's BATW requirements based on faulty assumptions about existing technology at those facilities. For example, H.A. Wagner (Unit 3) has a partial BATW recycle treatment system that would possibly need upgrades to meet the proposed BATW requirements. But EPA assumed this unit would not incur any costs. EPA, 2028 Unit-Level Industry Profile, EPA-HQ-OW-2009-0819-7707. Montour (Units 1 & 2) continue to rely on a surface impoundment BATW treatment system with a direct discharge, but EPA erroneously assumed the facility would not incur costs because it converted to a closed-loop or dry system in 2018. Id. Kingston (Units 1-9) have a RMDS dewatering system for which they would need to install full recirculation components to comply with the proposed BATW requirements. But EPA erroneously assumed the facility would only incur costs for a reverse osmosis membrane on a RMDS system. Id. Shawnee (Units 1-10) have a partial recycle BATW system for which they would need to install full recirculation components to comply with the proposed BATW requirements. But EPA erroneously assumed Shawnee's Units 1-9 would only incur costs for a reverse osmosis membrane on an RMDS system and Unit 10 would incur no costs. Id. There may be other examples not listed here.

8 Adjustment for the Coal Combustion Residuals (CCR)/Clean Power Plan (CPP)/Affordable Clean Energy (ACE) Rules

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 120

Comment Excerpt:

Another reason for underestimating the impacts of the 2015 rule likely is EPA's assumption that costs imposed by virtue of CCR rule requirements that prohibit the use of existing waste treatment facilities are costs of the CCR rule, rather than costs of the ELG rule. That is not the case. When a CCR rule requires the closure of an existing surface impoundment, the cost of the CCR rule is the cost of prematurely closing that impoundment. But the CCR rule does not in and of itself impose costs for treating the wastewater that can no longer be treated in the impoundment. The requirement to treat wastewater at all (or any preclusion against its discharge) is imposed by virtue of the CWA, and it is the CWA that determines the nature and cost of the technology that must be applied.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 130

Comment Excerpt:

The preamble to EPA's proposal suggests that the Agency believes that facilities affected by the rule will be able to comply by the December 31, 2023 deadline because "process changes should already have occurred" in order to allow these same facilities to comply with EPA's CCR rule, which it says requires the majority of unlined surface impoundments to stop receiving CCR wastewater, including BATW, by August 2020. 84 Fed. Reg. at 64,641. EPA assumes that such process changes will involve retrofitting under-boiler or remote mechanical drag chain systems because EPA concluded in the 2015 CCR rule that retrofitting such systems would be cheaper than building new, unlined impoundments. There are two flaws in this rationale. Id.

First, not all of the facilities subject to the 2015 ELG rule, or the Proposed Rule, rely on unlined surface impoundments. Some UWAG members use CCR-compliant surface impoundments to manage BATW at some of their facilities.

Second, facilities that must cease sending BATW to surface impoundments have found ways to achieve continued compliance with the currently applicable 1982 effluent limitations guidelines for TSS, pH, and oil & grease without building new lined surface impoundments or a dry or mostly dry management system. For example, one member maintains once-through dewatering bin systems throughout its fleet. Before the CCR rule, the company maintained these tank-based systems for their intended design purpose. The water is sluiced, via pumps, from the boiler hoppers into the dewatering bin. During sluicing, water overflows and proceeds to a polishing lagoon that is comingled with low volume wastewater. Once sluicing stops, water is further separated from the ash by decanting it into dewatering screens. The decanted water also goes to the polishing lagoons. The polishing lagoons are small and have retention times generally of a couple hours to days. Because of the comingling of various wastewaters, compliance is determined at the end of the polishing lagoon. The company determined the polishing lagoon produces *de minimis* amounts of CCR and thus is not subject to the CCR rule. It is also possible (and generally much cheaper than installing an RMDS) to meet current TSS, pH, and oil and grease limits by building concrete settling basins as substitutes for surface impoundments.

These approaches have been particularly important for units with low capacity utilization rates (which have difficulty affording major capital expenditures) or units that plan to retire or repower by 2028 (which must find a way to stop sending BATW to surface impoundments in time to complete closure by 2028, yet cannot justify an enormous capital investment to retrofit technology that will be used for far less than the standard 20-year depreciation period).

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 6

Comment Excerpt:

Finally, EPA has relied upon the Coal Combustion Residuals ("CCR") Rule to document why December 31, 2023 is the appropriate latest applicability date for BATW. EPA states, "Flexibility for facilities to comply with BAT limitations for BA transport water beyond 2023 is not necessary because the process changes should already have occurred due to CCR Rule requirements. Therefore, for BA transport water, the EPA proposes to continue the current timing for implementation." See 84 Fed. Reg. at 64,641. At several FirstEnergy facilities, the CCR Rule is not applicable for BATW systems, nevertheless the systems do not comply with the Proposed ELG Rule and would require significant capital upgrades. For instance, once through dewatering bin systems separate the bottom ash from the water, allowing non-CCR water to comingle with other low volume wastewaters without CCR applicability, but do not meet the Proposed ELG rules for BATW. These existing dewatering bin systems will require significant capital expenditures, along with detailed engineering designs, permitting, procurement, and commissioning. In fact, EPA is in possession of such information, as FirstEnergy provided it to EPA on, or around, February 28, 2018. See EPA-HQ-OW-2009-0819-7310, Attachment 35.

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 5

Comment Excerpt:

The proposed subcategory also supports the EPA's goal of aligning with the Coal Combustion Residual (CCR) rule. Currently all unlined coal ash surface impoundments[1] operated by CE, have provided notice to initiate closure and are following federal and state timelines to complete closure. At Karn all bottom ash transport water is currently sent to a CCR-compliant surface impoundment, with discharges regulated under the site's National Pollutant Discharge Elimination System (NPDES) Permit. By maintaining the proposed subcategory, the site can continue sending bottom ash transport water to CCR-compliant surface impoundments until retirement in 2023 and eliminate unnecessary costs to utility customers.

[1] "Unlined" meaning in this context that the surface impoundment must have at least a single composite liner system.

9 Subcategorization

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 4

Comment Excerpt:

II. THE PROPOSED NEW SOURCE SUBCATEGORIES ARE NECESSARY TO AVOID UNACCEPTABLE DISPROPORTIONATELY HIGH COSTS AND ADDRESS UNIQUE OPERATING CONDITIONS OF AFFECTED EGU SOURCES.

Santee Cooper generally supports EPA's proposal to establish three new subcategories of affected EGUs for limiting FGD wastewater and BA transport water under the 2015 ELG Rules. The proposed new subcategories would adjust the stringency of the technology-based effluent discharge limitations to cost-effective control levels based on unique operating conditions and other source-specific considerations for the following source subcategories: (1) boilers with low utilization levels, (2) electric generating facilities with extremely high FGD purge flow rates, and (3) boilers that will retire by no later than December 31, 2028. These adjustments to the effluent discharge limitations are necessary and appropriate based on EPA's authority under section 304(b) of the Clean Water Act ("CWA") to consider cost, the age of equipment and facilities, energy requirements, and other non-water quality environmental impacts. Although generally supportive of the proposed new source subcategories, Santee Cooper has a number of technical concerns regarding the provisions for implementing two of the subcategories – namely, those proposed for low-utilization and retiring units.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 5

Comment Excerpt:

TECHNICAL REVISIONS AND CLARIFICATIONS ARE NEEDED TO IMPROVE THE EFFECTIVENESS AND WORKABILITY OF THE PROPOSED REGULATIONS

FOR IMPLEMENTING THE REQUIREMENTS FOR THE NEW SOURCE SUBCATEGORIES.
Oglethorpe Power supports EPA's proposal to establish three new subcategories of affected EGUs for limiting FGD wastewater and BA transport water under the 2015 ELG Rules. The proposed new subcategories would adjust the stringency of the technology-based effluent discharge limitations to cost-effective control levels based on unique operating conditions and other source specific considerations for the following source subcategories: (1) boilers with low utilization levels, (2) electric generating facilities with extremely high FGD purge flow rates, and (3) boilers that will retire by no later than December 31, 2028. These adjustments to the effluent discharge limitations are necessary and appropriate based on EPA's authority under section 304(b) of the Clean Water Act ("CWA") to consider cost, the age of equipment and facilities, energy requirements, and other non-water quality environmental impacts. Although generally supportive of the proposed new source subcategories, the Corporation has a number of technical concerns regarding the provisions for implementing two of the subcategories – namely, those proposed for low-utilization and retiring units. The discussion below identifies those technical concerns for these two subcategories and, in each case, provides suggested revisions to improve the effectiveness and workability of the proposed procedures for implementing the requirements for the subcategories.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 7

Comment Excerpt:

Vistra encourages EPA to finalize its proposal to establish subcategories for boilers retiring by 2028 and low utilization boilers, with certain revisions. Such subcategorization is necessary because the cost and other non-water quality environmental impacts associated with boilers retiring by 2028 and low utilization boilers, in addition to the age of certain units, "are so fundamentally different from other plants on which the limitations are based that they cannot . . . achieve the effluent limitations . . . ."[4] As EPA explains in the Proposed Rule, when establishing ELGs based on BAT, Section 304 of the Clean Water Act requires EPA to take into account "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate."[5] Based on these factors, EPA then "determines whether plants within an industry should be assigned to a subcategory subject to more particularized regulations than the industry as a whole."[6] EPA has appropriately assessed these factors to determine that subcategorization for boilers retiring by 2028 and low utilization boilers is necessary, as discussed below.

[4] Chem. Mfrs. Ass'n v. EPA, 870 F.2d 177, 214 (5th Cir. 1989)
[5] 33 U.S.C. § 1314(b)(2)(B).
[6] Chem. Mfrs. Ass'n, 870 F.2d at 214; see also 84 Fed. Reg. at 64,624.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 3

Comment Excerpt:

- EPA appropriately proposes a subcategorization for low utilization units, which will—with a few modifications—avoid premature retirements and increase the resiliency of the grid during this critical period of transition within the industry.
- EPA also proposes to subcategorize units that certify to retire by December 31, 2028. This is well justified, given the significant costs the units would otherwise expend to meet new “best available technology” requirements.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 18

Comment Excerpt:

TVA supports EPA's decision to provide BATW subcategories for unit closure and low utilization boilers.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 4

Comment Excerpt:

CWLP is optimistic that provisions in the proposed rule for low utilization boilers and boilers that will permanently cease operation by 2028 will provide sufficient flexibility to allow for a smooth transition for our facilities that will allow them to operate, if economically and practically possible, until at least the dates at which the CCR program and the ELG requirements for Fly Ash Handling that have not been reconsidered will require them to shut down or spend $40 million ($21 million for Unit 33 only and $19 million additional for all three older Units) to convert to dry ash handling.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 1

Comment Excerpt:

Vistra generally supports EPA's Proposed Rule, particularly EPA's proposal to develop subcategories for boilers retiring by 2028 and low utilization boilers and EPA's proposal to add a 10 percent volumetric purge allowance for recirculating bottom ash transport water systems;

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 6

Comment Excerpt:

Yet, EPA would put in place exemptions, loopholes, and exceptions that would excuse utilities' failure to use and fully implement already-installed technology, compliance with existing permits, and adoption of available and proven technologies.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 14

Comment Excerpt:

And with its proposed carveouts for low-utilization plants and those retiring by 2028, EPA is proposing to allow unlined impoundments to serve as BAT, when EPA itself has demonstrated exhaustively that these primitive, leaking impoundments do not treat wastewater effectively.

Commenter Name: Josh Shapiro, Brian E. Frosh, Kwame Raoul, Dana Nessel, and Thomas J. Donovan, Jr.
Commenter Affiliation: Attorneys General of Maryland, Pennsylvania, Illinois, Michigan, and Vermont

Document Control Number: EPA-HQ-OW-2009-0819-8323-A1
Comment Excerpt Number: 4

Comment Excerpt:

As for the ELG Proposal, we take particular objection to EPA's proposed creation of more lenient subcategories for boilers whose owners intend to retire them by December 31, 2028, as well as "low-utilization" boilers. To support these subcategories, EPA offers little more than speculative concerns about the reliability of the electrical grid and conclusory statements about cost.
In actuality, the proposed subcategories are just one more subsidy for dirty, non-economical coal plants at the expense of public health and the environment.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 79

Comment Excerpt:

EPA also cannot create industry subcategories for plants based solely on their disproportionate compliance costs. It is well-established that "[w]ith respect to the overall impact of the [Act], Congress clearly contemplated that cleaning up the nation's waters might necessitate the closing of some marginal plants."[282] As the Court of Appeals for the D.C. Circuit has explained:

[T]he legislative intent [of the Act] is as clear as the result is harsh. Most prominently, the Act's supporters in both Houses acknowledged and accepted the possibility that its 1977 requirements[283] might cause individual plants to go out of business . . . They self-consciously made the legislative determination that the health and safety gains that achievement of the Act's aspirations would bring to future generations will in some cases outweigh the economic dislocation it causes to the present generation.[284]

The Fifth Circuit similarly emphasized Congressional intent in upholding EPA's decision *not* to subcategorize a group of plants based on cost despite the fact that the effluent limitations would "have a serious economic impact" on those plants.[285] In so doing, the Court explained that "Congress clearly understood that achieving the CWA's goal of eliminating all discharges would cause 'some disruption in our economy,' including plant closures and job losses," and therefore subcategorizing plants based on disproportionate compliance costs was not appropriate.

EPA would contravene the Clean Water Act's purpose if it created subcategories of plants with less stringent pollution-control requirements based solely on those plants' compliance costs. As courts repeatedly have explained, cost "is not a paramount consideration" in determining pollution control requirements.[286] Rather, EPA must select the best available pollution control technology that represents "a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges."[287] In making this selection, EPA is precluded from weighing pollution-reduction benefits against costs and instead must prioritize protecting the nation's waters over protecting plants' bottom lines. EPA would flip the Act on its head and violate Congressional intent if it created industry subcategories as a means of keeping dirty and marginal plants online. Carving out a subcategory for these worst-performing plants would run directly counter to the Act's requirement that BAT "be based on the single-best performing plant in an industrial field," which is to act "as a beacon to show what is possible" for the rest of the industry.[288]

[282] *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1051-52 (3d Cir. 1975).
[283] Although this quotation refers to the 1977 BPT requirements, Congressional intent and case law make clear that EPA owes even less consideration to costs in setting BAT limitations than BPT limitations. See, e.g., *Am. Iron & Steel Inst.*, 526 F.2d at 1051 ("It is immediately apparent that Congress contemplated that the Administrator should give greater consideration to the cost of compliance when defining 1977 'BPCTCA' technology levels than he should when defining the 1983 'BATEA' levels."); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 250 ("Both Congress and the Supreme Court have made clear that in setting BAT, the EPA is not required to compare the costs against the benefits of pollution reduction in the same manner as the EPA is required to do in setting BPT standards.").
[284] *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1036-37 (D.C. Cir. 1978).
[285] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 251.
[286] *BASF Wyandotte Corp. v. Costle*, 598 F.2d 637, 656 (1st Cir. 1979); see also *Am. Iron & Steel Inst.*, 526 F.2d at 1051 ("[I]t is clear that . . . the cost of compliance was not a factor to be given primary importance."); Weyerhaeuser Co., 590 F.2d at 1025 (explaining that Congress's commitment to cleaning up the nation's waters was illustrated "by the drafters' realization that enforcement of the Act would probably shut down some plants around the nation"); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 250 ("Because standards based on BAT, like BAT itself, reflect the intention of Congress to push industries toward the goal of eliminating the discharge of pollutants as quickly as possible, this goal is factored into determinations of the reasonableness of the costs associated with the regulation.").
[287] *Sw. Elec. Power Co. v. EPA,* 920 F.3d 999, 1030 (5th Cir. 2019) (quoting *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980)).
[288] Id. at 1018 (quoting *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 226 and *Kennecott v. EPA*, 780 F.2d 445 (4th Cir. 1985)) (internal quotations omitted).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 80

Comment Excerpt:

Finally, EPA cannot create subcategories unless those subcategorization decisions are supported by the rulemaking record in accordance with the Administrative Procedure Act. EPA's decision to create a subcategory is unlawful if its explanation for that decision "runs counter to the evidence before [it]" or lacks factual support in the record.[289]

[289] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983); see also *Sw. Elec. Power Co.*, 920 F.3d at 1022 (holding that EPA's BAT selection for

legacy wastewater was "wanting in light of the agency record" and therefore "arbitrary and capricious"); *Tex. Oil & Gas Ass'n*, 161 F.3d at 934 (agency action must "bear[] a rational relationship to the statutory purposes" and must be supported by "substantial evidence in the record").

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 81

Comment Excerpt:

A review of past ELGs reveals that, to date, EPA has created subcategories based primarily on plants' fixed characteristics and has rejected subcategories based on cost. Among the 58 ELG industry categories, EPA most frequently created subcategories based on the fixed characteristics of plants' raw material used, product type, or manufacturing process.[290] EPA rejected costs as a basis for subcategorization in several industries due in part to the variability of compliance costs.[291] EPA also frequently concluded that subcategories must relate to a facility's wastewater characteristics and therefore subcategories based on costs are inappropriate because costs have no effect on such characteristics.[292] Upon review of past ELGs, commenters found no instances in which EPA created industry subcategories based exclusively on cost.

[290] See, e.g., Development Document for Effluent Limitations Guidelines and Standards for the Nonferrous Metals Manufacturing Point Source Category, Vol. 1, 34 (May 1989) (10 subcategories based on raw materials) (attached); Development Document for Effluent Limitations Guidelines and Standards for the Electrical and Electronic Components Point Source Category (Phase I), 3-1 (Mar. 1983) (21 subcategories based on product type) (attached); Development Document for Final Effluent Limitations Guidelines and Standards for the Iron and Steel Manufacturing Point Source Category, 6-1 (Apr. 2002) (13 subcategories based on manufacturing process) (attached).

[291] See, e.g., Development Document for Effluent Limitations Guidelines and Standards for the Centralized Waste Treatment Industry, Vol. I, 5-2 (Aug. 2000) ("EPA did not use treatment costs as a basis for subcategorization because costs will vary and are dependent on the following wastestream variables: flow rates, wastewater quality, and pollutant loadings.") (attached); Development Document for Effluent Limitations Guidelines and Standards for the Inorganic Chemicals Manufacturing Point Source Category, 36 (June 1982) ("[T]he cost of treatment will fluctuate because of variations in quality, loading and flow rates and subcategorization on the basis of treatment cost is not recommended.") (attached); Development Document for Effluent Limitations Guidelines and Pretreatment Standards, and New Source Performance Standards for the Pesticide Chemicals Manufacturing Point Source Category, 4-7 (Sept. 1993) ("[T]he cost of treatment and the energy required will vary depending on flow rates, wastewater quality, and the amount and identity of pollutants in the wastewater. Moreover, alternative technologies could be selected by dischargers. Therefore, subcategorization based on treatment costs and energy requirements is not appropriate.") (attached); Development Document for Final Effluent Limitations Guidelines and Standards for the Pharmaceutical Manufacturing Point Source Category, 4-12 (July 1998) ("[T]he cost of treatment and the energy required will vary depending on flow rates and wastewater characteristics" and therefore "subcategorization based on treatment costs is not appropriate.") (attached); Final Development Document for Effluent Limitations Guidelines and Standards for the Transportation Equipment Cleaning Category, 5-15 (June 2000) ("Treatment costs vary significantly among facilities and are primarily dependent upon water pollution control technologies being used and on facility wastewater flow rates" and therefore "treatment costs alone are not considered an appropriate basis for subcategorization.") (attached); and Development Document for Final Effluent Limitations Guidelines and Standards for Commercial Hazardous Waste Combustors, 3-15 (June 2000) ("Treatment costs do not appear to be a basis for subcategorization because costs will vary and are dependent on the following wastestream variables: flow

rates, waste quality, waste energy content, and pollutant loadings. Therefore, treatment costs were not used as a factor in determining subcategories.") (attached).
[292] See, e.g., Development Document for Effluent Limitations Guidelines and Standards for Battery Manufacturing, Vol. I, 139 (Aug. 1984) ("The necessity for a subcategorization factor to relate to the raw wastewater characteristics of a plant automatically eliminates certain factors from consideration as potential bases for subdividing the category . . . treatment costs . . . have no effect on the raw wastewater generated in a plant.") (attached); Development Document for Effluent Limitations Guidelines and Standards for the Porcelain Enameling Point Source Category, 48 (Nov. 1982) (same) (attached); and Development Document for Effluent Limitations Guidelines and Standards for the Coil Coating Point Source Category, 36 (Nov. 1983) ("[T]reatment costs have no effect on the raw wastewater generated in a plant. The water pollution control technology employed at a plant and its cost are the result of a requirement to achieve a particular effluent level for a given raw wastewater load. It does not affect the raw wastewater characteristics, and thus does not impact subcategorization.") (attached).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 129

Comment Excerpt:

E. Neither the Retirement Nor the Low Utilization Subcategory Is Needed to Ensure Reliability.

In support of both the low-utilization and boilers retiring by 2028 subcategories, EPA advances unsubstantiated reliability justifications. In the case of the low-utilization subcategory, EPA states that "[l]ow utilization boilers tend to operate only during peak loading. Thus, their continued operation is useful, if not necessary, for ensuring electricity reliability in the near term."[430] In the case of the boilers retiring by 2028 subcategory, EPA noted that "utilities expressed the need for sufficient time to plan, construct, and obtain necessary permits and approvals for replacement generating capacity," and that "[i]n discussions of example Integrated Resource Plans (IRPs) and the associated process, utilities suggested timelines that would extend for five to eight years or longer."[431] EPA also refers to a recent report by North American Electric Reliability Corporation ("NERC") finding that reliability of the electric system would be reduced were a large percentage of the generating fleet retired without being replaced, and notes that "the well-planned construction of new generation capacity and orderly retirement of older facilities are vital to ensuring electricity reliability."[432]

Beyond these conclusory statements in the Preamble of the proposed rule, the sole support in EPA's record appears to be a single, five-page ERG memorandum that adds scarce additional detail to EPA's rationale.[433] The reliability arguments in support of these two subcategories are completely unfounded.

[430] 84 Fed. Reg. at 64,639.
[431] Id. at 64,640.
[432] Id.
[433] See ERG Memorandum, Steam Electric Effluent Guidelines Reconsideration – Evaluation of Potential Subcategorization Approaches, Docket ID No. EPA-HQ-OW-2009-0819-7911 (Aug. 29, 2019).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 82

Comment Excerpt:

In the 2019 Proposal, EPA has proposed creating three new subcategories that would be subject to less stringent pollution control requirements than the rest of the industry. Those subcategories would apply to high flow facilities, low utilization boilers, and boilers retiring by 2028.293 As explained in detail below, creation of each of these subcategories would exceed EPA's authority under the Clean Water Act and Administrative Procedure Act because they are based primarily on plants' compliance costs or lack sufficient support in the record.[294] EPA therefore must eliminate these three subcategories from the final rule.

[294] See, e.g., id. at 64,638 ("EPA is proposing to establish a new subcategory for facilities with high FGD flows based on the statutory factor of cost.").

Commenter Name: Jennifer Peters, et al.
Commenter Affiliation: Clean Water Action, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8462-A1
Comment Excerpt Number: 3

Comment Excerpt:

Proposed sub-categories to allow weaker limits for some plants are unjustified: EPA is also proposing new loopholes that will allow certain power plants to discharge even more pollution into our nation's waters. For example, if a plant operator claims a plant will retire by 2028, that plant would be completely exempt from these newer pollution limits. This would allow plants to unjustifiably continue to contaminate rivers, lakes, and streams across the country for five more years. EPA's proposal would also exempt plants that claim to only operate for a limited number of hours per year. EPA must abandon these loopholes that put utility profits above public health and the environment.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 4

Comment Excerpt:

Third, transport water for boiler slag generated in cyclone boilers contains few constituents of concern ("COC") and is materially different than the BA transport water generated by the majority of the industry. GSP Merrimack requests that EPA acknowledge this distinction by granting Merrimack Station (or, more generally, generators of transport water of boiler slag from cyclone boilers) a variance from the best available technology economically achievable ("BAT") effluent limits proposed for BA transport water or creating a BAT subcategory for cyclone boiler slag transport water.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 10

Comment Excerpt:

III. GSP Merrimack Requests a Variance or Subcategory for Cyclone Boiler Slag Transport Water.

GSP Merrimack requests a variance for Merrimack Station from the proposed BAT effluent limitations for BA transport water or the creation of a BAT subcategory for cyclone boiler slag transport water because such wastewater contains few COC and is materially different. In the Proposed Rule, EPA classifies all boiler slag (even slag from cyclone boilers) as BA and proposes to subject water used to transport slag to the same effluent limitations applicable to BA transport water. 84 Fed. Reg. at 64,628 n.9. EPA makes this classification with seemingly no consideration for actual, material differences in slag and the associated transport water generated by cyclone boilers and no justification for its conclusion.[7] GSP Merrimack requests that EPA reconsider this proposal by recognizing that boiler slag, and the associated transport water, generated by: (1) cyclone boilers in the industry is materially different; or, alternatively, (2) the cyclone boilers at Merrimack Station is materially different. Differences in this boiler slag and transport water justify a variance from the BAT effluent limits proposed for BA transport water or the creation of a BAT subcategory for such transport water. GSP Merrimack requests such a variance or the promulgation of such a subcategory and offers the following comments and Attachments 3-6 in support.

[7] Based on a review of EPA's 2013 proposed rule, 2015 final rule, the Proposed Rule, the associated "Supporting Documents" to these rules (including the agency's 2015 Response to Comments), as well as the associated administrative record available on www.regulations.gov, it does not appear that the record contains any underlying analysis to support EPA's apparent belief that boiler slag from cyclone boilers should be considered the same as BA. EPA's 2015 Response to Comments sets out the agency's general view that treating boiler slag as BA is consistent with EPA's regulatory practices and the technological and economic implications of complying with a rule that treats boiler slag as BA. However, the record does not appear to contain an explanation as to why boiler slag from cyclone boilers should be treated as BA despite the fact that such boiler slag is stable, inert, and has very low leaching characteristics and the corresponding slag transport water contains few COC compared to BA transport water generated by the majority of the industry.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC

Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 11

Comment Excerpt:

Both units at Merrimack Station have wet bottom cyclone-fired boilers, which produce slag as an end product. Molten ash from these boilers, once quenched in a tank, becomes slag (shown below)—a stable, inert, glass-like solid compound, which is very different from typical BA targeted in this ELGs rulemaking.

This stable, inert solid is conveyed through clinker grinders to reduce the size of the glass-like material, and the resulting slag material is then sluiced, or transported with water, to a collection area where it is dewatered and processed by a third-party company for 100% beneficial reuse as abrasive blasting material and/or roofing shingle aggregate. The decanted wastewater is subsequently discharged from the facility. The water used to transport boiler slag to the beneficial reuse facility at Merrimack Station contains minute concentrations of COC compared to what is found in typical BA transport water, and perhaps in other forms of cyclone boiler slag transport water generated by the industry. Two laboratory analyses of isolated slag transport water at Merrimack Station have been conducted in the recent past.[8] Both sets of analytical results prove cyclone boiler slag transport water at Merrimack Station is different. EPA's Technical Development Document for the 2015 ELG rule and this 2019 Proposed Rule each include a table that sets out the industry average concentrations of COCs found in BA transport water.[9] A comparison of these industry average concentrations to the Merrimack Station sampling results further confirms the cyclone boiler slag transport water at Merrimack Station is different. Concentrations in Merrimack Station's analytical results are less than the industry average—across the board. In fact, in many instances the Merrimack Station data is "non-detect," essentially meaning the COC is not even present in the cyclone boiler slag transport water. This comparison further supports GSP Merrimack's request for a variance or separate subcategory. EPA's toxic-weighted pound equivalent ("TWPE") methodology—which the agency relies upon to prioritize which wastewater streams, and which pollutants within those wastewater streams, warrant regulation—is also instructive and gives further credibility to GSP Merrimack's request. EPA's consultant, ERG, concluded in the 2019 rulemaking documents that the total TWPE/year discharged from 107 coal-fired power plants is 93,800.[10] Note that this TWPE/year number is a drastic reduction from the one EPA advanced in the 2015 rulemaking, which was 481,000 TWPE/year for 115 plants with a dedicated BA pond.[11] These numbers equal an average of approximately 876 and 4,182 TWPE/year, discharged per plant, respectively. The Electric Power Research Institute ("EPRI") conducted an analysis of the annual TWPE removal expected at Merrimack Station by and through implementation of a treatment technology designed to meet the "no discharge" limitation for BA transport water included in the 2015 ELG Rule.[12] EPRI utilized the two sets of analytical results of Merrimack Station's cyclone boiler slag transport water (Attachments 3 and 4), accounted for COC found in source water, converted the analytical value of the COC to TWPE, totaled all the TWPE values, and then multiplied that TWPE total by the estimated annual flow (gallons per year), which was 40 percent of the facility design flow at that time.[13] EPRI ultimately concluded that approximately 192 TWPE/year of discharges from cyclone boiler slag transport water at Merrimack Station would be eliminated. This is less than 22 percent of EPA's 2019 per-facility annual average number and less than 5 percent of EPA's 2015 per-facility annual average number. That makes Merrimack Station's cyclone boiler slag transport water materially different than the industry.

[8] See Letter from Eastern Analytical, Inc. re: Laboratory Report (July 22, 2013) (Attachment 3); Eastern Analytical, Inc. re: Laboratory Report (July 19, 2017) (Attachment 4).
[9] See EPA, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Dock. ID No. EPA-HQ-OW-2009-0819-6432, at 10-22 to 10-23, Table 10-7 (Sept. 2015) ("2015 TDD"); EPA Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Dock. ID No. EPA-OW-2009-0819-8211, at 6-12 to 6-13, Table 6-2 (Nov. 2019) ("2019 TDD"). Note that different industry averages exist elsewhere in EPA's administrative record for this rulemaking. See, e.g., EPA, Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Dock. ID No. EPA-HQ-OW-2009-0819-6427, at 3-18, Table 3-4 (Sept. 2015). Merrimack Station's analytical data is materially better and different than all of the industry data sets reviewed by GSP Merrimack.
[10] Memorandum from ERG re: Pollutant Loadings Analysis and Supporting Documentation for the 2019 Steam Electric Supplemental Environmental Assessment, EPA-HQ-OW-2009-0819-7733, at 7, Table 4 (Sept. 13, 2019).
[11] See 2015 TDD at 10-34 to 10-35, Table 10-14.
[12] See EPRI Comments on the Revised Draft Determination of Technology-Based Effluent Limits for Flue Gas Desulfurization Wastewater at Merrimack Station in Bow, New Hampshire, at Appx. B (Dec. 15, 2017) ("2017 EPRI Comments") (Attachment 5).
[13] See id.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 12

Comment Excerpt:

Moreover, operations at Merrimack Station have reduced dramatically in recent years. Thus, the 40 percent of design flow calculation utilized by EPRI inflates the TWPE actually discharged from the facility in recent years. Once baseload, the units at Merrimack Station now serve as seasonal and peak demand resources, critical to grid reliability. Set out in the table below are the discharge flow volumes (million gallons per year) and corresponding annual TWPE values from Merrimack Station's NPDES Outfall No. 003A from the last five years.[14] An average of the annual flows from these five years reduces EPRI's 192 TWPE/year number to 150 TWPE/year. The 2019 TWPE number for Merrimack Station would have been 144 TWPE/year (and this number would have been at its lowest in 2016, with a TWPE/year of 106). These values provide further support that the cyclone boiler slag transport water at Merrimack Station is materially different compared to the industry.

	mg/y	TWPE/y
EPRI Reference	584	192
Year		
2019	437	144
2018	666	219
2017	386	127
2016	322	106
2015	474	156
5 year average	457	150

The standards EPA has promulgated for granting a fundamentally different factors ("FDF") variance for individual permit holders also support GSP Merrimack's request for changes in this proposed rule. The regulations explicitly provide that a discharger "may request a variance from otherwise applicable effluent limitations . . . [f]or . . . best available technology economically achievable (BAT)" effluent limitations. 40 C.F.R. § 122.21(m). In deciding whether to grant such a request, a permit writer is to consider:

(1) The nature or quality of pollutants contained in the raw waste load of the applicant's process wastewater;

(2) The volume of the discharger's process wastewater and effluent discharged;

(3) Non-water quality environmental impact of control and treatment of the discharger's raw waste load;

(4) Energy requirements of the application of control and treatment technology;

(5) Age, size, land availability, and configuration as they relate to the discharger's equipment or facilities; processes employed; process changes; and engineering aspects of the application of control technology;

(6) Cost of compliance with required control technology.

Id. § 125.31(d). Factors (1) and (2) clearly support GSP Merrimack's request for the reasons already mentioned. Factor (6) also supports GSP Merrimack's request. The regulations provide additional detail on how cost should specifically be considered in evaluating a FDF variance request:

A request for the establishment of effluent limitations less stringent than those required by national limits guidelines shall be approved only if: . . .

(3) Compliance with the national limits (either by using the technologies upon which the national limits are based or by other control alternatives) would result in:

(i) A removal cost wholly out of proportion to the removal cost considered during development of the national limits.

Id. § 125.31(b)(3)(i). EPRI analyzed this issue and ultimately determined the cost-to-TWPE removal ratio for "dry handling" treatment technologies at Merrimack Station would be $2,724/TWPE (in 1981 dollars). 2017 EPRI Comments at 3. This is "fundamentally different" from the $314/TWPE EPA formulated for the industry in the 2015 ELG Rule[15] and no one could reasonably argue the costs for Merrimack Station are not "wholly out of proportion to the removal cost considered during development of the national limits."[16] The attached correspondence submitted to EPA Region 1 as part of the NPDES permit renewal process by the former owner of Merrimack Station, Eversource Energy, describes challenges that would be experienced in attempting to retrofit a "dry handling" treatment technology at the facility.[17] These issues are relevant to factor (5). The costs of "dry handling" technologies—if ultimately required—may also force GSP Merrimack to evaluate the economic viability of the facility (with future market conditions and forecasting critical to this analysis). This is also relevant to factor (5) and could be relevant to factor (4), as well. In the end, EPA should grant to Merrimack Station or all generators of transport water of boiler slag from cyclone boilers a variance from the BAT effluent limits proposed for BA transport water or create a BAT subcategory for cyclone boiler slag transport water. Such an action is supported by the enclosed analytical sampling data of Merrimack Station's slag transport water, especially when compared to industry average data included in the rulemaking documents. The request is also justified when this data is converted to TWPE. EPA relies upon TWPE values heavily in its rulemakings to inform whether additional treatment technology is feasible and justified. No technologies can reasonably be required for cyclone boiler slag transport water, given Merrimack Station's minuscule annual TWPE. GSP Merrimack's request is also supported by the regulatory factors EPA promulgated to evaluate whether to grant an analogous FDF variance. Almost all of these regulatory factors would support granting a variance or subcategory for Merrimack Station and any that arguably do not support such a request are simply neutral or immaterial to the specific situation. Cost is perhaps the most compelling of these regulatory variance factors. Because the slag transport water at Merrimack Station contains so few COC, the removal costs associated with technologies capable of eliminating the remaining COC in the wastewater are without question wholly out of proportion. For all these reasons, GSP Merrimack respectfully requests that EPA grant to Merrimack Station (or, more generally, generators of transport water of boiler slag from cyclone boilers) a variance from the BAT effluent limits proposed for BA transport water or, alternatively, create a BAT regulatory subcategory for cyclone boiler slag transport water.

[14] Boiler slag transport water is approximately 90 to 95 percent of the total flow through Outfall 003A. This TWPE analysis assumed slag transport water was the entire flow through the Outfall over the five-year period. It therefore overestimates the total TWPEs present in the transport water and the corresponding reductions that could occur if "dry handling" treatment technologies are utilized at Merrimack Station.
[15] See EPA, Regulatory Impact Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Dock. ID No. EPA-HQ-OW-2009-0819-5849, at F-12 (Sept. 2015).
[16] EPA has endorsed this cost-to-TWPE removal ratio to justify (at least in part) the LUB regulatory subcategory set out in the Proposed Rule. GSP Merrimack's slag transport water request is therefore consistent with the standards the agency is using with respect to other provisions in this same rulemaking.
[17] See Letter from Eversource Energy to EPA Region 1 (Feb. 17. 2017) (designated "Confidential Business Information," in accordance with 40 C.F.R. Part 2) (Attachment 6). Aspects of this February 17, 2017 correspondence were superseded by a subsequent letter. See Letter from Eversource Energy to Mr. Mark A. Stein, Sr. Assistant Reg'l Counsel, EPA Region 1 (Apr. 20, 2017), https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-1388.pdf.

Commenter Name: Ed Stone
Commenter Affiliation: Maryland Department of the Environment
Document Control Number: EPA-HQ-OW-2009-0819-8464-A2
Comment Excerpt Number: 3

Comment Excerpt:

Regarding EPA's proposal to regulate flue gas desulfurization (FGD) wastewater, EPA is basing the limitations in the 2019 Proposed Rule for FGD wastewater upon treatment using a combination of chemical precipitation and Low Hydraulic Residence Time Biological Reduction (LRTR) systems. This contrasts with the 2015 rule, which based limitations for FGD wastewater upon treatment using a combination of chemical precipitation and High Hydraulic Residence Time Biological Reduction (HRTR) systems.

Part VII.B.1 of the 2019 Proposed Rule (84 FR 64631) states "the types and amount of solids removed by the ultrafilter in the CP+LRTR treatment system are identical to the solids removed by the sand filter in the CP+HRTR;" "LRTR reductions are comparable to HRTR reductions;" and "the long term averages forming the basis of the selenium limitations for LRTR and HRTR are similar, and the higher selenium limitations for the LRTR systems are largely driven by increased short-term variability around that average." Furthermore, footnote #21, which is referenced in this same section, notes "FGD mercury and arsenic limitations in the 2015 rule were based on chemical precipitation data alone because the facilities operating biological systems were not using all of the chemical precipitation additives in the technology basis."

Drawing upon the above background and as further supported by the discussion of treatment technologies in Section 4.1 of the Supplemental Technical Development Document for the 2019 Proposed Rule, the Department suggests from EPA's information that the limits for arsenic, selenium, mercury, and nitrate-nitrite in the 2019 Proposed Rule may be achievable using chemical precipitation coupled with either LRTR or HRTR biological treatment. In this context, the Department requests the following additional subcategorization for FGD wastewater for permits issued under the current 2015 rule.

Specifically, the Department recommends that EPA subcategorize facilities with existing permits for FGD wastewaters issued under the 2015 rule and provide the states the delegated authority to maintain the implementation dates assigned in such issued permits. In addition, such a subcategory should provide states the authority to maintain the limitations for selenium and arsenic in such issued permits, established and issued under the 2015 rule, through the entire term of the permits and through all subsequent renewals, with the option for the State to adjust limits as follows: Limitations could be adjusted based on the actual optimized performance of the resulting treatment system upward to a ceiling bounded by the corresponding limitation in any final rule (if the updated limits for selenium and arsenic remains less stringent than the 2015 rule, as they are in the 2019 Proposed Rule). As referenced above, the increase to a less stringent selenium limitation in the 2019 Proposed Rule is "largely driven by increased short-term variability" of LRTR, so automatically applying such a relaxed limit for a facility which has a permit to achieve BAT under the 2015 HRTR technology based rule is problematic and should not be the only allowed outcome.

The Department also recommends that such a subcategorization approach also allow the permits issued under the 2015 rule to continue to implement the existing mercury and nitrate-nitrite limits in the timeframes specified within those permits. States would then establish appropriate "as soon as possible" deadlines on a case-by-case basis (using BPJ) for incorporating more restrictive requirements of any final rule including, but not limited to, mercury and nitrate-nitrite (should the final rule limitations remain more stringent than the 2015 rule, as they are in the 2019 Proposed Rule).

The Department also requests, consistent with the above subcategorization request and rationale for FGD discharges, that the permit limitations and timeframes in permits issued under the 2015 rule continue to be applicable to the subcategories in the 2019 proposed rule for low utilization units and facilities nearing retirement. The proposed elimination of selenium requirements for facilities in the low utilization subcategory is especially objectionable. One or more Maryland facilities may be eligible for the low utilization subcategory, but low utilization does not automatically translate to low concentrations or loadings of selenium.

Arsenic, mercury, and selenium are persistent and bioaccumulative toxic pollutants, and the fact that a facility may be below a statistical utilization level or permanently ceasing in another 8 years (i.e. under the proposed rule's retirement category) does not reduce the need for an as soon as possible improvement of its minimally controlled discharge (as compared to the 2015 treatment standards). Any cost/benefit analysis of the elimination of persistent and bioaccumulative pollutants needs to specifically consider the long and contentious history of the current proposed rulemaking, including the Department's comments on cost as described further below.

EPA requested comments regarding additional subcategorization and whether the 2015 rule limits would be appropriate for certain facilities. However, EPAs invitation(s) for comments seems to suggest it may only be interested in narrow subcategorization options, such as facilities that have installed biological systems but only where a membrane filtration system ends up being the final BAT, or facilities that have already invested and or started construction or implementation.[1] Instead the Department suggests a subcategorization approach based on permits issued under the 2015 rule, as described above.

Otherwise, EPA will be setting a precedent that risks encouraging facilities in the future to be slow in responding to implementation of requirements under the federal act and the implementing federal/state discharge permit, in the hopes of revised requirements in the future, complicating compliance and enforcement commitments, only to ultimately be rewarded by a new rule that restarts the clock even as they may have been developing plans to attempt to comply in a timely manner. Such an outcome might occur in spite of the fact that the State had determined the appropriateness of issuing such permits under the rule in effect at the time (in this current situation, the 2015 rule), doing so as the federally delegated CWA authority responsible for acting in the best interests of its citizens and the State, including its TMDL program, its water quality standards program, its drinking water protection program, and its obligations as the delegated authority for enforcement and compliance of these Clean Water Act Programs.

For example, the Department has issued three permits under the 2015 rule involving FGD wastewater and bottom ash transport water and is moving forward to the next step in the process prior to reissuance of a fourth permit. Two of the issued permits had issues related to TMDLs for nitrogen; one of the permits discharges to a freshwater receiving stream (i.e. a stream whose applicable freshwater criteria include the most restrictive aquatic life standards for selenium), and whose designated uses include public water supply. Also, two of the permits had longstanding noncompliance and enforcement issues needing resolution through permit renewal, and the third permit needed to be revised and reissued as part of the upstream facility's noncompliance solution. Finally, all three of the facilities with issued permits have been on the EPA toxics release inventory (TRI) listing for Maryland for releases to surface waters.

1 See 84 FR 64634 and 84 FR 64663 of the 2019 proposed rule.

Commenter Name: Ed Stone
Commenter Affiliation: Maryland Department of the Environment
Document Control Number: EPA-HQ-OW-2009-0819-8464-A2
Comment Excerpt Number: 4

Comment Excerpt:

Regarding EPA's cost estimates related to changing the 2015 rule at this time, it is certainly difficult to fully assess and quantify all of the environmental, public, private, and agency costs to be incurred by States in reversing a complex process already in place and underway in order to pause, cease, and retool to implement a new version of the rule with relaxed timeframes and a number of less stringent proposed requirements. A brief review of Maryland's experience on this issue is relevant. A 2010 memorandum issued by EPA's Office of Wastewater Management directed state permitting authorities to employ a case-by-case review of methods for limiting or eliminating the discharge of toxic pollutants pending changes in technology-based standards for FGD wastewaters. At that time, Maryland was already well into the process of issuing new permits for four facilities with FGD wastewaters, and we were imposing new requirements to implement biological treatment systems for those specific dischargers, not certain at the time what, if any, biological based systems would result in the pending national rule for FGD wastewater systems. But these systems were required at the time for protection of our nutrient budget (TMDL) for the Chesapeake Bay (and because enhanced nutrient reduction systems in Maryland have experienced significant reductions in suspended solids, which can indirectly reduce the discharge of some metals).

However, at that time and continuing until EPA's final 2015 rule, Maryland consistently took the position that it made little sense for Maryland to develop its own technology based requirements for pollutants not yet addressed by the outdated steam electric effluent guidelines for that industry while EPA was in the middle of its own long process to develop national requirements. Such an effort would occupy all existing permit resources in the Department, be a costly duplication of EPA efforts with no expected gains, with the potential for a short-lived outcome upon finalization of a national rule. Throughout that time period, the Department was criticized for this position, but it continued to wait upon EPA to complete its long-delayed rulemaking. In contrast to EPA statements in 2017 to wait for further federal developments, Maryland made the decision it would no longer continue relying on the suggestion of waiting for further EPA action. We began issuing permits under the 2015 rule.

So now that EPA's 2015 rule is finally complete, after all of these years, and Maryland finally has effective permits under that rule, and we are now being called upon through this proposed rule to relinquish our implementation efforts and instead concede that we were too early in embracing EPAs 2015 final rule because, for whatever reasons, the rule needs to be pulled back and reassessed?

Considering this long history, and with an economic impact consideration of the persistent and bioaccumulative toxic pollutant discharges associated with this history, we request that EPA more fully account for the unknown full cost of reversing course on permits issued under the EPA 2015 final rule and implement our requested approach for an additional subcategory for facilities with permits issued under the 2015 rule.

9a <u>Subcategorization – Retirements and Fuel Conversion by 2028</u>

Commenter Name: Rachel Procter
Commenter Affiliation: Consumers Energy Company (CE)
Document Control Number: EPA-HQ-OW-2009-0819-8291-A1
Comment Excerpt Number: 3

Comment Excerpt:

CE supports the proposed subcategory for boilers retiring by Dec. 31, 2028. CE plans to retire its D.E. Karn (Karn) Units 1 and 2, both of which are coal-fired, in 2023. This plan has been approved in our recent Integrated Resource Plan (IRP) filing with the Michigan Public Service Commission (MPSC) and has received MISO’s approval to suspend Karn Units 1 and 2 operations without the need for the units to be designated as a System Support Resource (SSR).

Allowing CE to avoid additional compliance costs under the NOPR's eventual final rule protects our customers from significant costs that can be reallocated to other investments, such as renewable energy development, energy efficiency measures, ensuring reliable electric service. We estimate that, absent the retirement exemption, CE would need to spend approximately $31 million to bring the Karn Units 1 and 2 into compliance with the rule.

Commenter Name: Jeffrey L. West
Commenter Affiliation: Xcel Energy Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8294-A1
Comment Excerpt Number: 2

Comment Excerpt:

Xcel Energy supports the EPA's proposal to subcategorize the BAT limitations for boilers retiring by 12/31/2028 to BPT limitations for TSS, based on gravity settling surface impoundments. The proposed date of 12/31/2028 is a reasonable planning horizon for retiring impacted units.

EPA's proposal is in alignment with Xcel Energy's efforts to transition our fleet to higher efficiency units that support our new fleet generation mix that will include more renewable energy generation so that we can achieve our interim goal of reducing carbon emissions by 80% by 2030 while keeping our customer bills affordable.

For regulated utilities like Xcel Energy, the 2028 planning horizon is particularly important, as it provides State public utility commissions sufficient time to review and approve proposed retirements. We agree that there are significant cost implications for a retiring unit to comply with the 2015 ELG rule. EPA's proposal for units retiring prior to 12/31/2028 is consistent with prudency requirements for regulated utilities and mitigates the potential investment in a stranded asset that may not be eligible for rate recovery, which would ultimately be costly to our customers and shareholders.

Commenter Name: Jeffrey L. West
Commenter Affiliation: Xcel Energy Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8294-A1
Comment Excerpt Number: 3

Comment Excerpt:

The support documentation required to support the certification of the estimated date of retirement from service should not be prescriptive - EPA has solicited input regarding the information that should be submitted to support the certification of the estimated date that an affected boiler will be retired from service. Xcel Energy recommends that EPA should not be too prescriptive when identifying the documentation to support these certifications. Variances in State utility commission processes necessitate some flexibility. We recommend that EPA identify categories of documents that can be used to support these certifications such as a utility commission Resource Plans, certification from company official, official notices to Regional Transmission Organizations and applicable FERC submittals.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 3

Comment Excerpt:

Specifically, EPA should:

…

- Finalize the proposed subcategory for retiring boilers since it is consistent with both past agency action and judicial precedent and will result in overall reduced pollutant discharges. EPA should clarify that this subcategory also applies to units that are repowering (with non-coal fuel sources) by December 31, 2028. EPA also should further develop the proposed subcategory for low-utilization units;

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 9

Comment Excerpt:

Third, EPA should finalize its proposed retirement subcategory, since it is consistent with past Agency action as well as judicial precedent and will result in overall reduced pollutant discharges. EPA has strong reasons for creating a subcategory based on the economic impacts from imposing BAT limits on units likely to retire in the near to medium term, and in terms of *overall* effluent discharges, units that retire by a date certain represent avoided future discharges. These retirements represent significant environmental gains from avoided effluent discharges, and EPA should realize those benefits by finalizing the proposed subcategory.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)

Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 22

Comment Excerpt:

V. EPA Should Finalize the Subcategory for Boilers That Can Certify Retirement.

EPA proposes to establish a new subcategory for boilers retiring by December 31, 2028 based on the statutory factors of cost, age of equipment and facilities involved, non-water quality environmental impacts, and other factors. 84 Fed. Reg. 64,640. For such boilers, EPA is proposing to set surface impoundments as BAT and to establish BAT limitations for TSS, for both FGD wastewater and BATW. Id. The Agency proposes that these are considered BAT for the retirement subcategory due to the "unacceptable disproportionate costs they would impose; the potential of such costs to accelerate retirements of boilers at this age of their useful life; the resulting increase in the risk of electricity reliability problems due to those accelerated retirements; and the harmonization with the CCR rule." Id. In essence, the Agency concludes that the creation of this subcategory would address concerns about burdening electricity customers with increased costs because capital investments would have to be depreciated over a shorter useful life versus and the risk that post-retirement rate recovery could be denied for the significant capital and operating costs associated with the BAT options that EPA has identified.

A. EPA's Retirement Subcategory Will Result in Overall Environmental Benefits and Is Consistent with Other Environmental Programs.

The proposed retirement subcategory is consistent with past agency action as well as judicial precedent and will result in overall reduced pollutant discharges. EPA has strong reasons for creating a subcategory based on the economic impacts from imposing BAT limits on units likely to retire in the near to medium term, given that payback periods for units are often 15 to 20 years or greater, depending on individual circumstances. Additionally, in terms of *overall* effluent discharges, units that retire by a date certain represent avoided future discharges; in terms of overall discharges, units that retire or repower with fuels other than coal represent environmental benefits through avoiding future discharges.[17] These environmental benefits are tangible: units that cease utilization of coal as a fuel source do not have the effluent discharges at issue here in the Proposed ELG Rule and retiring or repowering of these units provides an avenue to cease these discharges for all future periods. Simply because the Agency has created a time-limited subcategory out to 2028 does not necessarily mean that all units in this subcategory will operate until the end of 2028—unit retirement decisions are subject to a number of factors including economic viability, grid reliability considerations, regulatory approvals, among many others. Due to these processes and factors, unit retirements are scheduled over numbers of years—as can be seen from existing public announcements, a significant number of units representing approximately 120 GW of capacity have either already retired or are slated to be retired in the coming years. See EEI Retirements Chart, attached as Appendix A. These retirements represent significant environmental gains from avoided effluent discharges, and EPA should realize those benefits by finalizing the proposed subcategory.

The Agency is also on firm legal footing by establishing a specific subcategory for units that are planning to retire in coming years. EPA has explicitly taken such an approach under the CWA, specifically in its 2014 final rule titled *National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*. 79 Fed. Reg. 48,300 (Aug. 15, 2014) (Final 316(b) Rule). EPA explicitly notes that it considered that "Unit closures provide clear reductions in flow … EPA expects flow reductions due to unit closures could be reasonably included as part of a facility's impingement mortality and entrainment reductions strategy." 79 Fed. Reg. at 48,332. The regulations for cooling water intake structures under CWA section 316(b) contain exemptions for units that are scheduled to retire before the expiration of the current permit—permittees that planned to retire their facilities before their then-current permit expired did not need to comply with substantive portions of the rule. See 40 C.F.R. § 122.21(r)(ii)(F). Units that are scheduled to retire within one permit cycle would not be subject to the substantive portions of the rule so long as they signed a certified statement specifying the facility's last operating date. Id. at § 122.21(r)(ii)(G).

EPA has also used a similar approach in other environmental statutes, like the Clean Air Act (CAA), most notably in both the regional haze rule and in designations for the sulfur dioxide (SO2) National Ambient Air Quality Standards (NAAQS). In both of those CAA programs, EPA acknowledged that retiring or repowering units would suffice for compliance with those federal environmental requirements as long as the retirements were federally enforceable by a date certain. EPA's establishment of a subcategory for retiring units to avoid unnecessary costs and requirements is not unique.

In the regional haze program, EPA has utilized its discretion to allow for units that are retiring not be required to install control technology that would be otherwise required under an analysis of Best Available Retrofit Technology (BART). The CAA requires each regional haze plan to "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress" toward the statutory goal of eliminating manmade visibility impairment in Class I Federal areas. See 42 U.S.C. § 7491(b)(2). Similar to the factors required for EPA to review in the CWA for promulgating ELGs, when determining what measures amount to "reasonable progress," a State must consider four criteria: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and nonair quality environmental impacts of compliance; and (4) the remaining useful life of any existing source subject to such requirements. Id. at § 7491(g)(1).[18]

While the regional haze program has had a focus on source-specific evaluations of the above BART factors, important for this analysis is that EPA and States have concluded in numerous different contexts that an evaluation of all of the above factors leads to the imposition of no further controls given the pending retirement of the source in question. This has primarily been the result of an analysis of the remaining useful life of the source when weighed against the other four BART factors; specifically, that the installation of pollution control technology can impose significant costs for some environmental gains, but that those costs and environmental benefits do not outweigh the environmental and economic benefits of simply retiring the source.[19] When promulgating air quality designations under CAA section 107(d) for the SO2 NAAQS, EPA acted pursuant to a consent decree with environmental petitioners to designate areas in several different groups. Crucially, the Agency specifically stated that areas that had electric generating units that had announced an upcoming retirement and cease of operations date did not need to be classified as not attaining the NAAQS, since their pending retirement obviated the need for further regulatory actions an implementation of nonattainment provisions.[20] In essence, the Agency crafted a regulatory category that specifically took account of unit retirements. Accordingly, unit retirements provide long-term environmental benefits, which EPA has recognized. These unit closures should be recognized under the CWA as providing similar benefits.

[17] Similarly, units that repower to utilize natural gas no longer will have effluent discharges related to the utilization of coal, and therefore do not need to be regulated by the ELGs here.
[18] To ensure States achieve "reasonable progress," every plan must require certain large-scale, stationary sources of air pollutants to implement controls known as BART, or adopt a BART alternative. Id. at § 7491(b)(2)(A); 40 C.F.R. § 51.308. The CAA defines BART as being based on a source-specific evaluation of five factors. See Oklahoma v. EPA, 723 F.3d 1201, 1208 (10th Cir. 2013). These "BART factors" are: (1) The costs of compliance; (2) The energy and non-air quality environmental impacts of compliance; (3) Any existing pollution control technology in use at the source; (4) The remaining useful life of the source; and, (5) The degree of visibility improvement which may reasonably be anticipated from the use of BART. 42 U.S.C. § 7491(g)(2).
[19] Most recently, EPA has endorsed such an approach in its approval of Arkansas' Regional Haze State Implementation Plan and withdrawal of a Federal Implementation Plan wherein the Agency determined that there was no need to install pollution control technology on BART eligible units given that those units had an enforceable order to switch the type of coal used and then to cease use off coal by the end of 2028. See Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas, 84 Fed. Reg. 51,033 (Sept. 27, 2019). Specifically, EPA concluded that Arkansas satisfied the requirements of the CAA by "fully considering the five statutory factors…Taking into account the remaining useful life of White Bluff Units 1 and 2 (based on Entergy's enforceable Administrative Order to cease coal combustion by December 31, 2028), and the resulting cost-effectiveness of controls, as well as the anticipated visibility improvement of the SO2 control options and the other BART factors." Id. at 51,036.
[20] The Agency's second round of designations specifically focused on areas that "contain any stationary sources that had not been announced as of March 2, 2015, for retirement and that according to the EPA's Air Markets Database emitted in 2012 either (i) more than 16,000 tons of SO2, or (ii) more than 2,600 tons of SO2 with an annual average emission rate of at least 0.45 pounds of SO2/mmBTU." Response to Significant Comments on the Designation Recommendations for the 2010 Sulfur Dioxide Primary NAAQS, Docket No. EPA-HQ-OAR2014-0464 (June 30, 2016).

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 23

Comment Excerpt:

B. EPA Should Finalize Requirements to Certify Retirement and also Explicitly Include Units that Repower in the Subcategory.

EPA should allow units to utilize multiple avenues to certify boiler retirement or repowering to natural gas. In the proposal, EPA defines the term retired from service to mean "the owner or operator of a boiler no longer has, or is no longer required to have, the necessary permission through a permit, license of other legally applicable form of permission to conduct electricity generation activities under Federal, state or local law." 84 Fed. Reg. at 64,672. And the rule requires owners or operators of "retired from service" units to provide, among other things, a "copy of the most recent integrated resource plan, certification of boiler cessation under 40 C.F.R. § 257.103(b), or other legally binding submission supporting that the boiler will be retired from service by December 31, 2028." Id. at 64,677. In addition to the acceptable submissions referenced in the regulatory text, EPA also should further specify that owners or operators can submit the following to demonstrate retirement by December 31, 2028:

- Federal Energy Regulatory Commission (FERC) Form 1, which is an annual regulatory requirement for major electric utilities, licensees and others which contains extensive information on asset retirement obligations, depreciation schedules for retirements, dates announced for retirements in other financial reporting forms, and other information relating to asset retirement. See 18 C.F.R. § 141.1.
- Relevant FERC tariff forms utilized by Regional Transmission Organizations/Independent System Operators (RTOs/ISOs) certifying rescission of the tariff to interconnect and provide power to the RTO/ISO. An example of this would be the Midcontinent Independent System Operator's (MISO) Attachment Y.[21]

Further, the definition of "retired from service," (proposed 423.11(w)) may not adequately account for facilities that intend to repower utilizing a different fuel source—specifically, facilities that are repowering to utilize natural gas as a primary fuel source or facilities with single unit retirements among remaining operating units. EPA should make clear that the subcategory for retiring boilers encompasses repowering facilities, given that facilities repowering to gas no longer will create the waste streams regulated by the ELGs for the power sector at issue in the Proposed ELG Rule.

EPA should explicitly note that the retirement subcategory includes units that will repower by December 31, 2028, and that the definition of "retired from service," which includes the requirement that "the owner or operator of a boiler no longer has, or is no longer required to have, the necessary permission through a permit, license of other legally applicable form of permission to conduct electricity generation activities under Federal, state or local law" does not apply to repowering units that can generate electricity with other fuel sources and not subject to the regulations under this Proposed Rule. EPA also should note that repowering can happen at any time and does not need to be completed by a date certain in order for the contents of the rule to no longer be applicable to such sources in future years. EPA proposes that as part of the permit renewal or re-opening, "facilities submit a one-time certification to the permitting authority stating the date of expected retirement from the combustion of coal, and provide a citation to any filing, integrated resource plan, or other documentation in support of that date." 84 Fed. Reg. at 64,667. EPA asserts that this will provide the permitting authority further evidence that a boiler will, in fact, cease the production of electricity by that date." See id. Sources should be able to submit this form at any time in advance of the 2028 deadline, not only on a one-time, time of permit issuance basis to qualify for the 2028 subcategory.

[21] MISO, FERC Electric Tariff, Attachment Y, Notification of Generation Resource/SCU/Pseudo-tied Out Generator, Change of Status, Including Notification of Rescission (Jul. 16, 2018), https://cdn.misoenergy.org/Attachment%20Y109858.pdf.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 19

Comment Excerpt:

6. The proposed Retirement Subcategory is appropriate.

EPA proposes to establish a new subcategory with the ELGs for coal fired units that have a limited remaining operational life. For this subcategory EPA proposes that companies who certify to retire coal fired units can be allowed to operate the units until December 31, 2028. In the 2019 proposal, the units operating within this subcategory will be subject to existing BAT standards until December 31, 2028. This subcategory is needed to address end of life units in which the expense of new environmental control equipment that would be needed for ELG compliance are not economically appropriate for the company and ratepayers. EPA should consider the following items when finalizing this subcategory.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 20

Comment Excerpt:

A. The Retirement Subcategory should include units that are repowered by December 31, 2028

Excluding repowered units from the Retirement Subcategory would discourage repowering at existing coal-fired facilities. This is a critical consideration since power providers must make repowering decisions in conjunction with retrofit or retirement decisions. Making a retirement or repowering decision requires a power provider to work with Independent System Operators (ISOs), transmission owners, Public Service Commissions and others to determine prudent resource decisions required to ensure electrical grid reliability. Repowering should be a viable option to retirement as a generation resource and electrical system reliability planning process. Like retirement, repowering eliminates all pollutants related to coal-firing. Repowering a coal-fired unit with natural gas, for example, is a viable option for power providers because much of the critical infrastructure is already in place, including transmission lines, substations, and water. Also, repowering at the same facility ensures that the site is already approved and permitted for generation activities and discourages unwarranted development of "greenfield" sites for new generation. By excluding repowered units from the Retirement Subcategory, EPA would discourage permittees from repowering units to compensate for retiring units. It would discourage permittees from using ideal sites (former coal-fired units/facilities) for their repowering projects. EPA should certainly take the opposite approach by including repowered units in the Retirement Subcategory to encourage reuse of existing power generation facilities, which is both economically efficient and environmentally beneficial. As EPA analysis has shown, it is not economically prudent for a power provider to retrofit a coal-fired unit that will retire in a short time. In the same way, the retrofit expense for a unit that will be repowered in a short timeframe is also not a wise use of resources. While repowering a coal-fired unit should be a viable resource option to retirement, the economic burden of retrofit costs for a short-term operation of the coalfired unit would make it unfeasible to implement a repowering option. Repowering will (1) provide a valuable option to maintaining electric grid reliability while (2) eliminating the pollutants related to coal-firing. As the ELG standards are finalized, the power provider will then have the necessary information to begin the detailed evaluation required to make an informed retrofit, repower or retire decision. Preliminary technology and system evaluations can be conducted earlier, but an understanding of the final ELG Rule standards and requirements is necessary to fully evaluate the economic and technical implications of retrofit, repower or retire options. In addition to substantial analysis during the initial planning period, the process to plan for and complete any new transmission and/or generation projects will also take several years. This will include fuel supply infrastructure projects for repowering projects to convert coal-fired generating units. Generally, these projects require time for siting/routing, design, land acquisition, permitting, procurement, and construction. Many constraints influence the timing of these projects and are not within the permittees' control. Many states have established requirements to maintain necessary amounts of generation resources to meet anticipated demand. In these jurisdictions, resource planning and generator retirement decisions must be approved by regulators or other governmental agencies. In some cases, it can take years to obtain authorization from grid operators and PSCs to decommission units. Maintaining mandatory grid reliability standards (e.g., NERC standards) after permittees start decommissioning units or while units are temporarily closed for repowering is a primary consideration. Regional Transmission Organizations (RTOs) typically require prior notification and time to conduct detailed grid reliability analysis before retirements, outages, or extended periods of non-operation. Time to coordinate and carefully plan these projects is essential. Loss of generation of a power plant requires careful analysis up front to maintain electrical system reliability, and much of this process is out of the utility's control.

Overall, the entire process of planning and constructing new transmission and/or generation infrastructure will take a significant amount of time because it is complex and involves many elements outside of the utility's control. This time is necessary to fully study the final ELG Rule, work with regulators and ISOs to gather enough information to make a final decision on whether to retrofit, repower, or retire units. The numerous considerations and lead time required to repower a coal-fired unit are similar to the considerations and timing required to retire a coal-fired unit and therefore, repowered units should be included in the Retirement Subcategory of the final ELG Rule.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 21

Comment Excerpt:

B. Companies should be allowed two years to formally certify use of subcategory.

The 2019 proposal would require facilities to submit a one-time certification to the permitting authority and it would have to be submitted with a permit application (NPDES) or when a permit is re-opened[17]. EPA should amend this requirement to change the deadline for submittal of the certification, which should be up to two years from the date of final rule promulgation. There are two reasons for this proposed change to the existing certification requirement. First, setting a standard timeframe for companies to make a decision about unit retirement or repowering will not only simplify the process, but also provide for regulatory certainty for both companies and regulatory agencies. Next, under the current requirement, there are some companies that will be at a huge disadvantage because of the renewal date of existing NPDES applications. For example, DTE has a facility in which permit requirements were established for ELG compliance following the 2015 Rule. Then because of the 2017 Postponement Rule, the permit was reopened to modify the requirements due to the modified applicability dates. Upon promulgation of the final ELG Rule, the permit will need to be reopened in order to modify ELG requirements in early 2021. This timeline will not allow for an adequate economic analysis for unit retirement or repowering, which is a vital component of the decision making process to utilize this proposed subcategory.

[17] Fed. Reg. Vol 84, p. 64677

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 3

Comment Excerpt:

Similarly, the establishment of new source subcategory for retiring coal-fired EGUs is needed to avoid stranded costs and disproportionately high compliance costs. To improve the effectiveness and workability of EPA's proposal, Santee Cooper recommends that EPA also creates several other new source subcategories that would extend the retirement deadlines in order to further support the orderly transition to a new fleet of cleaner and more efficient electric generating resources.

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 7

Comment Excerpt:

B. A Subcategory For Retiring Boilers Is Necessary To Avoid Stranded Costs And Unacceptably High Compliance Costs.

EPA is proposing to establish a new source subcategory for coal-fired boilers with a limited useful life that will retire by no later than December 31, 2028. These retiring boilers would only be subject to effluent discharge limitations for total suspended solids ("TSS") based on gravity settling through the use of surface impoundments for both FGD wastewater and BA transport water. These TSS limitations would apply in lieu of imposing significantly more stringent effluent discharge limitations based on chemical precipitation with biological treatment for reducing discharges of FGD wastewater, and dry ash handling or closed-loop wet ash handling system for reducing BA transport waters. Santee Cooper supports the proposed adoption of a new source subcategory for retiring boilers with the less stringent effluent discharge limitations for the following reasons. First, market conditions in the electric power sector have shifted significantly over the past decade. These changes have included increased supplies of inexpensive natural gas and technological advances in solar, wind, and other renewable energy resources. As a result of these market trends, rate of coal-fired power plant retirements has accelerated in recent years and this trend of early retirements will most likely continue, if not increase, with the aging of the coal-fired generating fleet and the mounting pressures for the electric power sector to reduce its carbon footprint.[5] The adoption of a new source subcategory for retiring units is necessary to avoid the potential for stranded costs that would be incurred by requiring these facilities to make major capital investments for pollution control equipment near the end of their useful life. Furthermore, it is appropriate exercise of EPA's standard-setting authority under section 304(b) of the CWA, which directs EPA to consider cost, the age of the equipment and facilities involved, and non-water quality environmental impacts (including energy requirements). Second, retiring units would incur unacceptably high compliance costs if they were required to install the reference control technologies (as noted above) that were used for setting effluent discharge limitations for FGD wastewater and BA transport waters for the general source category. These disproportionately high costs would mainly be incurred due to the fact that a retiring unit would be unable to amortize major capital and O&M costs across a 20-year life of the newly installed control technologies (which was the time period that EPA used for justifying the cost-effectiveness of the proposed effluent discharge limitations). This economic assessment was specifically confirmed by the Agency itself in both the preamble to the Proposed Rule and a technical support document. In particular, EPA determined that a retiring EGU "could be forced to pass on capital costs per MWh 10 to 15 times higher than those passed on with the assumed 20-year amortization in EPA's cost estimates, and the costs per MWh remain more than double the EPA's estimates until amortization of six to eight years, depending on the discount rate."[6] Third, the imposition of these high compliance costs could accelerate the retirements of those coal-fired EGUs that are no longer being used as baseload generating units, particularly given that they are approaching the end or their useful life. The accelerated early retirement of significant amounts of existing coal-fired generating capacity could, in turn, increase the risk of electricity reliability problems. One notable study confirming these electric reliability risks is a recent North American Reliability Corporation (NERC) report documenting through a "stress test scenario" assessment that significant reliability risks could result from the premature retirement of large coal-fired and nuclear facilities if those retirements were to occur faster than the construction of necessary replacement generating capacity.[7] The proposed adoption of a new source subcategory for retiring coal-fired EGUs (with less stringent effluent discharge limitations) would address this concern by ensuring the orderly and well-planned replacement of such retiring units retirement with new generation, along with the necessary transmission and other ancillary electric infrastructure. In particular, it would allow the electric power sector to continue its organized phasing out of coal-fired generating facilities that are no longer economical or reaching the end of their useful life, in favor of new highly efficient and low- or zero-emitting generating units without posing the electric reliability risks identified above in the NERC report.

[5] 84 Fed. Reg. at 64,640. See also Supplemental Technical Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Section 3, ("Supplemental TDD").
[6] 84 Fed. Reg. at 64,640. See also Supplemental TDD at Section 3.
[7] North American Electric Reliability Corporation, Special Reliability Assessment: Generation Retirement Scenario (December 18, 2018). Available online at:
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%2ODLLIVERCRetirements_Report2018_Final.pdf
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Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 8

Comment Excerpt:

And finally, Santee Cooper has a technical concern regarding the proposed timeframe by which owners or operators must make an election to retire their coal-fired boilers. This concern, which is similar to the one described above for low-utilization units, is the proposed deadline for submitting to the permitting authority the one-time certification statement that the boiler will be retired by December 31, 2028. In particular, the regulatory text in the Proposed Rule states that the certification "must be submitted with the permit application, or where a permit has already been issued, by the as soon as possible date determined under paragraph 423.11(t)."[8] This requirement fails to specify any minimum date by when the submission must be made. Given that NPDES permits have already been issued to the vast majority of, if not all, existing generating facilities, one possible reading of the proposed regulatory text is that every owner or operator of a retiring boiler must submit its certification statement by November 1, 2020 (which is a deadline date that could precede the promulgation date of a final ELG rule) unless the owner or operator is able to secure an extension from the permitting authority (which may not be later than December 31, 2023). This approach is confusing and creates considerable uncertainty on what is the deadline for submission of the one-time certification statement to the permitting authority. To clarify this situation, Santee Cooper recommends that EPA revise proposed section 423.19(f)(1) to require that the initial certification statement be submitted to the permitting authority by a date certain, specifically within three years from the promulgation date of the final ELG rule in the Federal Register.

[8] 84 Fed. Reg. at 64,677 (citing proposed 40 C.F.R. §423.19(f)(1)).

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 10

Comment Excerpt:

III. EPA SHOULD CREATE OTHER NEW SOURCE SUBCATEGORIES FOR LONGER-TERM RETIREMENTS THAT OCCUR AFTER 2028.

In the preamble to Proposed Rule, EPA requested comment on a number of important issues relating to the proposed retirement deadline of December 31, 2028. Those issues included whether "a date earlier or later than 2028 would be more appropriate" and "if a date after 2028 would be warranted, and what an appropriate retirement date might be."[9] Santee Cooper is providing responses to EPA's inquiries in the following two sections. Section A below presents many of key reasons why a retirement deadline of December 31, 2028 reflects the minimum amount of time that is needed to build new replacement generating capacity and, as a result, that the proposed retirement deadline should not shortened under any circumstances. This discussion is followed in Section B by proposals to extend the retirement deadline beyond 2028 to accommodate many possible initiatives now under consideration to shut down existing coal-fired generating facilities and bring online replacement capacity under a time schedule that is slightly longer eight years, specifically within time range of ten to twelve years.

A. The Proposed 2028 Retirement Deadline Should Be Retained At Minimum.

Santee Cooper believes that the retirement deadline date should remain December 31, 2028 and not be shortened under any circumstances. A long lead time is necessary to complete the design, permitting, financing, procurement, and construction of the necessary replacement generating capacity. Even under best case situations, building and bringing online the new generating facilities can take up to five or six years to complete. Additional time will sometimes become necessary due to circumstances beyond the control of the electric utility. For example, lengthy project delays can frequently result from legal challenges to the permits or other federal, state, or local approvals that are typically necessary for construction of any major new generating facility. In many cases, a project to build replacement capacity may also require the construction of other critically important energy infrastructure necessary to support the deployment of new generating facility. Notable examples include the buildout of a natural gas pipeline and the necessary transmission lines for delivering the electricity from the new facility to the load centers. One notable case in point is the effort that has been underway for many years to build a new natural gas pipeline through West Virginia, Virginia, and North Carolina. Referred to as the Atlantic Coast Pipeline, this major energy infrastructure has been subject to lengthy construction delays due to various legal challenges to the many federal, state, and local permits and authorizations that are necessary for building a 600-mile underground pipeline across three states. In addition, the proposed "safety valve" mechanism for extending the retirement deadline in the case of those generation facilities that fail to retire by 2028 is not of much help. An extension would most likely not be available due to many circumstances that are beyond the control of the electric utility, such as major unexpected delays in the construction of the new replacement generating unit or other important infrastructure for the project (e.g., buildout of natural gas pipeline or transmission lines). Rather the extension would be limited to only those cases in which the Department of Energy has issued an emergency order requiring continued operation of the EGU under section 202(c) of the Federal Power Act ("FPA") or a public utility commission has issued a reliability must-run agreement. The issuance of such an emergency order or must-run agreement is infrequent and limited only to providing relief in emergency situations. As a result, EPA's proposed safety valve provision would not serve as a reliable mechanism for extending the retirement deadline due to a wide range of extenuating circumstances that do not necessarily involve an emergency electric reliability problem meeting the stringent requirements for issuing a FPA section 202(c) order or a reliability must-run agreement. For these reasons, Santee Cooper believes that a retirement deadline of December 31, 2028 is the absolute minimum amount of time that is needed to complete the orderly transition from the retiring to new generating capacity and would urge EPA to lengthen it, if possible, on the basis that units slated for retirement are not running very much anyway. In the alternative, we urge that EPA consider developing other regulatory options, as described below in the next section, to extend the retirement deadline another few years until December 31, 2032. Santee Cooper also recommends the addition of an "off-ramp" for facilities which may need to operate for a longer period of time due to unanticipated circumstances. We recommend such facilities be given one year to agree to a compliance schedule with their regulator and up to five years to construct new treatment technology.

B. EPA Should Create Other New Source Subcategories To Support The Transition To New Fleet Of Cleaner and More Efficient Generating Resources.

As explained in the previous section, a retirement deadline of December 31, 2028 will most likely not be sufficient to ensure an orderly transition for some coal-fired EGUs that may retire over the next decade. To address this concern, Santee Cooper urges EPA to establish new source subcategories that would establish appropriate effluent discharge limitations for existing coal-fired EGUs that are scheduled to retire over the next decade (specifically units with a remaining useful life that is greater than eight years but less than twelve years). One objective of these new source subcategories is to support the transformation that is now underway in the electric power sector to close existing coal-fired power plants and transition to renewable energy and other low- and zero-emitting energy resources. Requiring electric utilities to incur major capital compliance costs to comply with stringent new effluent discharge limitations also does not make good policy sense for this class of retiring units. It could in fact hinder, rather than help to facilitate, an orderly and efficient transition to cleaner and more efficient electric generating resources in South Carolina and other states. In addition, it would be inconsistent with the requirements of the CWA10 for EPA to establish effluent discharge limitations that are reasonable and economically achievable for all affected facilities within the particular source category. Under these proposed approaches of establishing new subcategories of longer-term retiring EGUs, EPA would establish alternative effluent discharge limitations that would moderate the stringency of the limitations to ensure the reasonableness and economic achievability of the control requirements. A brief summary of these additional new subcategories is provided below.

1. We support UWAG's proposal of a new subcategory that would be equivalent to the 50 MW units which are currently excluded from regulation. These units would be those that generate less than 438,000 MWhs according to a two-year rolling average. This is equivalent to a 50 MW unit running at baseload. Further, as was discussed earlier, logically there is no reason facility averaging should not be available as well. This subcategory has potential to alleviate problems associated with developing new generation and to maintain grid reliability.

2. We support UWAG's proposal of a new subcategory for low utilization units scheduled for retirement. Under their proposal, such units would get an extra three years to retire. This aligns with reality (low utilization units do not run much, do not generate much wastewater, and those slated for retirement will soon eliminate their discharge altogether). We would suggest the retirement exemption provide four years to retire, rather than three. Again, this subcategory has potential to alleviate problems associated with developing new generation and to maintain grid reliability.

3. For facilities that operate above the generation thresholds noted previously but which plan to retire, we suggest a new subcategory that would allow additional time to construct replacement generation. Discharge limitations for facilities in this subcategory should be set on a case-by-case basis by the state or federal regulatory authority based on "best professional judgment" ("BPJ") in order to reflect the variety of source-specific factors for ensuring the establishment of reasonably achievable and cost-effective control levels. Key elements of each provision are briefly outlined below.

Scope of Source Subcategory: New subcategory would apply to those retiring coal-fired EGUs with a remaining useful life that is greater than eight years but less than twelve years. In particular, the subcategory would apply to those existing units that are scheduled to be retired, but will need to operate over an extended time period that shall not exceed twelve years from the promulgation date of the final ELG rule.

Source-Specific Discharge Limitations: This subcategory of coal-fired units would be subject to a source-specific effluent discharge limitation based on a BPJ analysis that allows for the consideration of the remaining useful life of the unit and other unique design and operating considerations of the retiring unit. This approach makes sense because it avoids stranded costs by not requiring major capital investments that are going to be retired over the near term, while still requiring the installation of cost-effective control measures to limit discharges during interim period. As a general matter, the effluent discharge limitation would be limited to those cost-effective measures for reducing pollutant discharges that do not require major capital investments. This would result in the establishment of an effluent discharge limitation that is less stringent than the new effluent discharge limitation that EPA will establish for units with a remaining useful life of greater than twelve years. In the case of FGD wastewater, this effluent discharge limitation could be based on various less capital-intensive control options, such as physical and chemical treatment with the addition of specified chemicals to the ponds or FGD systems in order to precipitate metals and other constituents in the wastewater. In addition, the setting of source-specific effluent limitations based on BPJ will allow the regulatory authority to consider other unique design and operating circumstances that will affect the performance and cost-effectiveness of the control options for reducing effluent discharges during the limited compliance period prior to retirement. Notable factors that should be considered in making the BPJ determination include the following:

- Planned retirement date of the affected unit;
- Size of the affected unit;
- Projected annual capacity factor of the affected unit under current energy forecasts;
- Projected dispatch of the affected unit, including the extent to which the unit is expected to cycle and follow load or be dispatched at a baseload steady-state under current energy forecasts;
- Projected flow rates and discharge levels of the particular unit under projected utilization levels during the interim period; and
- Other relevant unit-specific factors.

Compliance Deadlines. Two separate deadlines would apply to this particular source subcategory of retiring EGUs. The first deadline would be for compliance with the alternative effluent discharge limitation for this new subcategory of retiring EGUs. Santee Cooper recommends that EPA set this compliance deadline at five years from the promulgation date of a final rule. An extension of up to two years may be obtained if additional time is needed to achieve compliance with the alternative limitation. The effluent discharge limitation with the specified compliance deadline would be incorporated as a permit condition into the NPDES permit at the same time that the federally enforceable requirement to retire the unit (i.e., three years from the promulgation date of a final rule.) The second deadline would be the date by which the retiring unit must permanently cease commercial operation to generate electricity. The retirement deadline would be a date that is twelve years from the promulgation date of the final rule.

Election Process: The owner or operator of the retiring EGU must make a federally enforceable commitment to retire the designated unit within two years from the promulgation date of the final rule. To make an election to retire the unit, a letter must be submitted to the appropriate EPA and the state regulatory authorities within two years from promulgation date of the final rule. The commitment to retire the unit would be irrevocable and become federally enforceable through the establishment of permit condition in the NPDES permit for the unit. The permit condition to retire would be incorporated into the NPDES permit within three years from promulgation date of the final rule. Assuming that EPA promulgates a final rule in November, 2020, the milestones for the implementation of the requirements for this new subcategorization of retiring units would be as follows:

DATE	MILESTONE
November, 2020	EPA issues final ELG rule
November 2022	Owner or operator submits a letter making an irrevocable commitment to retire the designated existing EGU
November, 2023	The permit condition to retire the existing EGU is incorporated into the NPDES permit
November, 2025	The retiring unit must begin to comply with the alternative discharge effluent limitation established for retiring units unless it obtains an extension of up to two years.
November, 2032	The retiring unit permanently ceases commercial operations to generate electricity.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 12

Comment Excerpt:

E. EPA Should Finalize the Proposed Retirement Subcategory

The Group strongly supports EPA's proposal to establish a new subcategory for boilers retiring by 2028.[22] First, these units will be retiring in the near term and thus their FGD and BATW waste streams will be completely eliminated. Further, because the cost estimates used for other subcategories assume that facilities will amortize both capital and operations and management costs across the 20-year life of technologies, applying those cost estimates to retiring facilities does not account for the fact that retiring facilities have an abbreviated lifespan.[23] Overhauling facilities in order to comply with new regulatory requirements is a substantial investment and burden on both facilities and customers, with very limited short-term environmental benefit and no long-term environmental benefit. Creating a subcategory for retiring facilities, as EPA proposes, would mitigate these concerns without lessening environmental benefits. While CCIG strongly supports the establishment of the subcategory for boilers retiring by 2028, EPA should clarify that a coal-fired unit that is repowered to fire on natural gas should also be treated as a retiring unit eligible for the new subcategory for several reasons. First, regardless of whether a company decommissions a coal-fired unit or repowers it, the result will be the complete elimination of BATW and FGD wastewater discharges. Thus, from an environmental perspective, there is no basis to distinguish retiring units from those repowered on natural gas. Second, repowering a coal fired unit requires substantial investment, and EPA's amortization of costs across a 20-year technology life does not create an accurate picture of true costs for those facilities. Indeed, EPA's Economic Impact Analysis—one of the lynchpins of its Regulatory Impact Analysis—included no estimate of the costs or economic impacts that would result from requiring units that will repower by December 31, 2028, to install BATW or FGD wastewater treatment technology that they would use for only three to five years. Instead, EPA removed those facilities from the industry profile for purposes of assessing the costs and economic impacts of the rule. For instance, Talen Energy's Brunner Island plant was listed in a July 31, 2019 report by Eastern Research Group, Inc. as being repowered by 2028 and did not estimate any costs to be incurred by the plant for BATW or FGD waste waters based on that understanding.[24] Therefore, as with units retiring by 2028, requiring a coal-fired unit that is being repowered to fire on natural gas to comply with the same regulatory requirements as coal-fired units that are not being repowered would create an unwarranted burden that doesn't achieve additional environmental benefits. That burden can be mitigated by either creating a new subcategory for units that are being repowered or by expanding the subcategory for retiring boilers created in the Proposed Rule. If EPA elects not to include repowered facilities in the retirement subcategory or provide a new subcategory for such units, it must account for and explain the basis for distinguishing repowered facilities from retired facilities.

[22] Id. at 64,640.
[23] Id.
[24] This report is included in the docket for the Proposed Rule as document EPA-HQ-OW-2009-0819-7373.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 16

Comment Excerpt:

Retirement Subcategory
FirstEnergy supports a retirement subcategory to avoid exacerbated premature retirements due to complying with costly environmental regulations. FirstEnergy offers certain comments to the retirement subcategory to make it more meaningful and representative of reality.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 17

Comment Excerpt:

Retirement Certification
The Proposed ELG Rule's retirement certification is confusing at best, and at worst, significantly limiting to the permittee. By setting the time period sometime between the permit application or

as soon as possible but no later than the applicability date, there is significant ambiguity in the date that the permittee must notify the respective agency. Also, permittees, like FirstEnergy, have permits that are currently in the process of being renewed which was never clarified in the Proposed Rule. This uncertainty could lead to an initial certification date of November 1, 2020.

Retirements are a very complex and sensitive subject matter not only to the permittee but also the various stakeholders, including the locality in which the unit resides. Thoughtful consideration of all the factors that go into a retirement are required and can take a significant amount of time. The planning horizon for power generation assets is generally decades into the future, with some of FirstEnergy's assets currently being 50 or more years old. FirstEnergy proposes that the certification be submitted to the Agency no later than December 31, 2023 which would allow the permittee to conduct a thoughtful analysis of retirement and the alternatives that exist.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 18

Comment Excerpt:

Retirement Timing
While FirstEnergy generally supports the December 31, 2028 date for retirement, it comes with the caveat that the most likely replacement for coal fired generation is a natural gas combined cycle ("NGCC") power plant. As such, the siting of a new power plant on an existing site has several environmental and financial advantages versus siting a new power plant on a greenfield site. FirstEnergy's former Hatfield Power Plant was an attractive site to an NGCC developer due to the existing infrastructure of the former plant. One problem with siting a new NGCC power plant at existing coal fired power plants in some parts of the country is limited access to pipeline infrastructure. Pipeline infrastructure can be a very time-consuming exercise, over which, the electric utility has very little control. Pipelines currently in development have run into a number of challenges, such as environmental permitting and appeals or neighboring property issues.[3] As such, FirstEnergy proposes that a condition be included that if natural gas infrastructure issues delay the development of an NGCC site, the permittee will be granted up to a two-year extension to the December 31, 2028 date to be granted by the permitting authority. As EPA has during this and previous rulemakings, it should consult with the CCR Rule personnel and align closure dates in the CCR Rule with the ELG Rule.

3 Sullivan, Sean. "PennEast Pipeline Seeks Two-Year in-Service Delay, Citing Permitting." S&P Platts Global, S&P Global Market Intelligence, 31 Dec. 2019, www.spglobal.com/platts/en/market-insights/podcasts/crude/011320-capitol-crude-peakpermian-capital-flight-risk.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 13

Comment Excerpt:

For the retirement subcategory, UWAG supports a retirement deadline of December 31, 2028, as EPA has proposed. But we seek some adjustments to the subcategory. First, units that certify that they will repower by December 31, 2028, should be included in the subcategory. Just as unit retirement ends any generation of BATW or FGD wastewater, repowering accomplishes the same thing. There is no reason to treat repowered units differently than retired units under this rule. Also, the retirement certification should not require that the owner/operator surrender the facility's permit or license to generate electricity. This is counter-productive, as it would impact gas units that are co-located with retiring coal units. The NPDES regulations assure that a formal certification by a responsible corporate official binds the company to the action being certified. Nothing further should be required. As to the timing of retirement/repowering certification, we recommend that EPA set a deadline of December 31, 2023, for filing of the certification. This will allow companies an opportunity to analyze the rule and possible compliance strategies and to attain necessary approvals for retirement or repowering of units. Any shorter timeframe would be unworkable.

Commenter Name: Mike Krumland
Commenter Affiliation: Nebraska Public Power District (NPPD)
Document Control Number: EPA-HQ-OW-2009-0819-8308-A1
Comment Excerpt Number: 4

Comment Excerpt:

NPPD supports the BAT for units retiring by December 21, 2028; however, EPA should expand this category to include units that will be re-powering and streamline the certification process.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 4

Comment Excerpt:

Similarly, the 2019 Proposed Rule includes a retirement subcategory. For boilers retiring by December 31, 2028, "BAT limitations would be set equal to BPT limitations for TSS based on the use of surface impoundments." 84 Fed. Reg. 64630. GenOn would also not be able to take advantage of the retirement subcategory if the date remains the same because, again, it would have already procured and installed the technology required under the 2015 ELG Rule. The 2015 rule does not include a retirement option for bottom ash transport water. Therefore, a November 1, 2020 date will likely mean that bottom ash transport equipment will be installed at economically stressed facilities that may be retired between December 31, 2023 and December 31, 2028.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 13

Comment Excerpt:

10. The EPA should allow owners of coal-fired boilers that opt to retire before 2028 to withdraw their elections to retire and continue operating their plants if they immediately implement ZLD technology when their election is reversed.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 31

Comment Excerpt:

Certifications under PSES for boilers retiring by 2028

As part of the proposed subcategory for those boilers retiring by December 31, 2028, EPA is proposing a reporting and recordkeeping requirement which mandates that when facilities are making the request to be included in this subcategory, the facility must submit a one-time certification stating the date of the expected retirement from the combustion of coal, and provide a citation to any filing, integrated resource plan, or other documentation in support of that date. It is not entirely clear to CWLP who would receive this certification. Since CWLP is a direct discharger as well as an indirect discharger, a retirement certification for our older units would be submitted to the NPDES authority Illinois EPA.

If for some reason, CWLP determined to submit such a certification for Dalman Unit 4, under the PSES it would go to the Control Authority. Under 40 C.F.R. 403.3(f) the Control Authority is either the POTW, if their pretreatment program has been approved by the Approving Authority or the Approving Authority if it has not. Under 403.3(c), the Approving Authority is either the Regional Administrator of the appropriate region or the State Director in an NPDES State with an approved State pretreatment program. Illinois is, of course, an NPDES state, but it does not having an Approved Pretreatment Program. So in CWLP's case the approving authority is the Regional Administrator. Although SCWRD has submitted a program update to USEPA that has not yet been approved, CWLP assumes that SCWRD would qualify as the Control Authority for this provision based on the previous approval of their program by USEPA.

While CWLP is in the process of determining retirement dates for its older boilers as a result of an Integrated Resource Plan ("IRP") completed in 2019, CWLP has no plans to retire Dallman Unit 4 at this time. However, the IRP did show the marginal nature of even Unit 4 such that if CWLP's compliance costs for Unit 4 alone are significant under the PSES CWLP will have to seriously consider whether there is an incentive in the regulation to retire Unit 4 prematurely. Unit 4 was opened in 2009 and the City financed the costs of that facility with bonds that have a pay pack end date of 2040. The debt service on those bonds is $36.6 million per year. Retiring Unit 4 prior to 2040 would result in stranded assets for our customers. However, given the current market conditions and regulatory uncertainty at the State level, CWLP will have to be open to the idea that Unit 4 may need to be retired before the end of its useful life before making a large additional capital expenditure. In order to make a decision of whether to take advantage of that option, CWLP would need to study the cost of implementing a new biological treatment pretreatment system for Unit 4 only (which assumes the shutdown of our older units) and determine whether that cost alone is sufficiently less than $45 - $50 million to allow CWLP to operate beyond 2028. There is a possibility the FGD PSES rule will shorten the remaining useful life of our facility by incentivizing CWLP to commit to a 2028 retirement date to avoid capital expenditures that will become additional stranded assets, but CWLP does not today have the information to make that determination and would not want to be pressured to make it such an important decision hastily.

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 13

Comment Excerpt:

EPA should amend the proposed retirement subcategory to include boiler repowering or replacement.

The Agency has proposed a subcategory for boilers retiring by 2028, with BAT based on surface impoundments. Cleco fully supports this subcategory as a sensible means of avoiding unjustified costs and stranded investments. The Agency has also requested comments on "whether this subcategory should also be available for boilers that are planned to be repowered or replaced by 2028, not just those planned for retirement."[65] Cleco takes the view that the subcategory should include repowering or replacement of boilers, and it suggests modest changes to the proposed rule to achieve that result.

Coal-fired generation has long played a critical role in supplying affordable, reliable electricity to American consumers, especially those in Louisiana. While the total generation from these units might be falling, it cannot disappear altogether without serious disruption to grid reliability. That threat is amply demonstrated by the North American Electric Reliability Corporation ("NERC") study described in the preamble, which assumes only premature retirement.[66] Cleco thus agrees with EPA's views that " the well-planned construction of new generation capacity and orderly retirement of older facilities are vital to ensuring electricity reliability."[67] Cleco believes that view applies with equal force in the areas in which it serves customers.

In Cleco's case, repowering is particularly important because the company is considering repowering a coal-fired unit at Big Cajun II to natural gas. While repowering might be construed as "retired from service" in some sense of the phrase, Cleco has concerns that the proposed definition of this phrase does not do so with enough clarity.[68] Of greatest concern is that it appears to require the owner to certify that the boiler will no longer "conduct electricity generation activities[.]"[69] Unlike retirement, boiler conversion (repowering) is intended to allow the boiler to continue to conduct electricity generation activities using a different fuel.

This definition should be amended to specify that boiler conversion qualifies for the subcategory, or EPA should provide a separate definition for repowering and adjust language elsewhere in the proposed regulatory text to apply to retirement from service or repowering. [70] Cleco suggests that the final rule might read "retired from service or <u>converted to burn a non-coal fuel</u>." Alternatively, EPA might borrow language from the CCR Rule. That rule's alternative closure provisions tum on "permanent cessation of a coal-fired boiler[.]"[71] This language would need to be slightly changed to read "permanent cessation of coal firing" or something similar; it is not the "boiler" after conversion that ceases but the burning of the coal.

[65] Id. at 64,641.
[66] See id. at 64,640.
[67] Id.
[68] See id. at 64,672 (to be codified at 40 C.F.R. § 423.11(w)).
[69] See id. (to be codified at 40 C.F.R. § 423.11(w)).
[70] For example, seeking coverage under the subcategory requires a certification that the boiler "will be retired fromservice[.]" Id. at 64,677 (to be codified at 40 C.F.R. § 423.19(f)(1)).
[71] 40 C.F.R. § 257.103(b)(1).

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 14

Comment Excerpt:

EPA should ensure that permit applicability dates accommodate the retirement or repowering decision-making process.

To qualify for the retirement subcategory, the proposed rule requires the owner to submit a certification "with the permit application, or where a permit has already been issued, by the as soon as possible date determined[.]"[72] Cleco is not confident that this language permits utilities enough time to secure the regulatory permission they must obtain before certifying retirement. A permit application, for example, might be due very soon after this rule takes effect merely thanks to the luck of the five-year renewal cycle. Cleco sees no basis for denying the ability to certify future retirement on that basis.

The "as soon as possible" or applicability dates might be better options for a certification deadline than the permit cycle, but the proposed rule could be tightened in this regard. For one thing, some facilities will have separate "as soon as possible" dates for BATW and FGD wastewater. If that proves true, then it is not clear which date controls the timing of the retirement certification.

Cleco recommends that the final rule clarify that the certification is due by the later of the two " as soon as possible" dates. The second date is preferable because it provides more time to secure approval from public utility regulators. That approval is not instantane~us and might take multiple years to request and obtain.

To reinforce the harmony between the retirement certification and the "as soon as possible" dates, EPA should also clarify in the final rule that permitting authorities may explicitly consider the time required to obtain regulatory approval for retirement in setting those dates. It makes little sense to mandate expensive upgrades without knowing whether the facility will, or even can, retire a boiler, and any reasonable permitting authority should recognize the need for careful planning around a decision of such magnitude.

[72] See Proposed Rule, 84 Fed. Reg. at 64,677 (to be codified at 40 C.F.R. § 423.19(f)(1)).

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 7

Comment Excerpt:

Buckeye generally supports establishing a subcategory for boilers retiring early.

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 8

Comment Excerpt:

However, there are facility-wide compliance issues brought on by having this subcategory. All of Cardinal's FGD wastewater is treated in one location. As Buckeye evaluates potential technologies for ELG compliance, the new equipment (if required) will be sized to treat water from all three units. If one or more of the boilers is certifying early retirement, the facility should be able to size the equipment for the post-retirement configuration of the plant. The compliance deadlines for the remaining unit(s) should be extended. This should be addressed on a case-by-case basis in the NPDES permit either by US EPA or another permitting agency.

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 9

Comment Excerpt:

Additionally, a 10-year window from the date of finalizing the rule is more appropriate for a closure date.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 1

Comment Excerpt:

Facilitate continued delivery of clean, safe, reliable and affordable energy: EPA should include subcategories for units that will be retired, replaced or repowered that appropriately consider the timing and processes associated with system resource planning and any associated regulatory approvals.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 7

Comment Excerpt:

Retirement subcategory

- We support the retirement subcategory and recommend that EPA include scenarios of repowering or replacing generation. EPA should also modify the qualification and certification timing and criteria to more appropriately accommodate state regulatory approval processes.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 89

Comment Excerpt:

Proposed § 423.13(g)(2)(i); § 423.13(k)(2)(ii). Units qualifying for the exemption would not have to meet the other new BAT limits for FGD wastewater and BATW. UWAG generally supports the proposed Retirement Subcategory, with a few recommended modifications as outlined below.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 90

Comment Excerpt:

A. The Retirement Subcategory Should Include Units that are Repowered.

EPA solicits comment on whether the Retirement Subcategory should include units that are planned to be *replaced* or *repowered* with non-coal fuel sources[161] by 2028 and, if so, whether BAT should be the same as for retiring units. 84 Fed. Reg. at 64,641 (emphasis added).[162] UWAG strongly agrees the Retirement Subcategory should include repowered units. Those units certified to be repowered should be subject to the same BAT basis as units certified to be retired for all the reasons discussed below.[163]

1. Like Retiring Units, Repowering Eliminates All Pollutants Related to Coal-Firing.

The Agency "removed coal-fired generating units that will retire or convert fuel type prior to December 31, 2028, from the analyses supporting this proposed rule because they will cease discharging FGD wastewater or bottom ash transport water prior to the date of compliance…." Supplemental TDD at 3-4. Whether a permittee decommissions a coal-fired unit or repowers it, the result will be the complete elimination of BATW and FGD wastewater discharges, which are the subject of this rulemaking.

[161] UWAG uses the terms "repower" and "fuel conversion" interchangeably. They both refer to converting a unit's fuel source from coal to non-coal sources.
[162] It is unclear what EPA means by "replaced," as a separate category from "retired" units. Many units slated for retirement will be replaced by non-coal units that will not be subject to the Rule.
[163] Discharges from coal-fired units are the focus of this rulemaking and this Subcategory. So, for units that are included in this subcategory because they are certified to be retired or repowered, the requirement should be that those certified units cease coal-fired operations by December 31, 2028, not that the decommissioning process or repowering project be complete by that date. Ceasing coal-fired operations means that the unit will also cease generating BATW and FGD wastewater.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 91

Comment Excerpt:

See id.at 6-3, n.39 ("The EPA determined that baseline and post-compliance *pollutant loadings are equal to zero for … units that announced plans to retire, convert to a non-coal fuel source,* or change/upgrade ash handling practices by the time the … units are required to meet the requirements of the proposed rule.") (emphasis added). The environmental benefits gained from the Proposed Rule's BATW and FGD wastewater requirements are the same regardless of whether a unit is retired or repowered. In terms of BATW and FGD wastewater discharges, there is no environmental basis for distinguishing between the two for the purpose of this rulemaking.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 92

Comment Excerpt:

2. Excluding Repowered Units Would Discourage Repowering at Existing Coal-Fired Facilities.

As EPA's updated industry profile illustrates, permittees often make repowering decisions in conjunction with retirement decisions. See ERG, *Review of Company Rational for Retirements, Deactivations, and Fuel Conversions,* EPA-HQ-OW-2009-0819-7374 (Feb. 27, 2019) ("ERG, EPA-HQ-OW-2009-0819-7374"). EPA's industry profile identifies approximately eight plants that have or will repower (i.e., refuel) in conjunction with retirement or deactivation of coal units. Id. This demonstrates that repowering is a common strategy for reducing reliance on coal-fired generation.

In addition, EPA's industry profile demonstrates repowering is increasingly common at former coal-fired facilities. The Agency identified 27 plants that, as of October 2018, had converted or planned to convert coal-fired units to a different fuel source. (ERG, 2019 Industry Change Memo), Table A-3, at 18-19.

Repowering units on the same site as a former coal-fired unit is a common practice because existing infrastructure and permits can continue to be used and the property is already an established industrial site. According to the EIA, there are four main phases of a coal-fired unit decommissioning—retirement, decommissioning, remediation, and redevelopment.[164] Redevelopment "may involve repurposing the site for another generation technology or some other commercial, industrial, or municipal application. Coal-fired power plants typically occupy land in or near downtown areas or along rivers, and they usually have access to railways, roadways, water, sewers, and other infrastructure."[165] Repowering an entire power plant with natural gas, for example, is "a viable option for power providers because much of the critical infrastructure is already in place, including transmission lines, substations, and water."[166] Also, repowering at the same facility ensures that the site is already approved and permitted for generation activities and discourages unwarranted development of "greenfield" sites for new generation.

By excluding repowered units from the Retirement Subcategory, EPA would discourage permittees from repowering units to compensate for retiring units. It also would discourage permittees from using ideal sites (former coal-fired units/facilities) for their repowering projects. UWAG urges EPA to include repowered units in the Retirement Subcategory to encourage reuse of existing power generation facilities, which is both economically efficient and environmentally appropriate.

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[164] As noted above, eligibility for this subcategory should be based on whether units certified to retire or repower cease coal-fired operations by December 31, 2028, not whether the decommissioning process or repower project is complete. A unit may cease coal-fired operations before December 31, 2028, but the repowering project associated with that retirement may not be complete until after that date because it takes place during the later "redevelopment" phase.
[165] EIA, *More U.S. Coal-Fired Power Plants Are Decommissioning as Retirements Continue* (July 26, 2019), https://www.eia.gov/todayinenergy/detail.php?id=40212 (last visited Dec. 16, 2019).
[166] EIA, Id.; *see also* Don Hopey, *New Castle power plant switching to natural gas,* PITTSBURGH POST-GAZETTE (June 24, 2013), https://www.post-gazette.com/local/region/2013/06/24/New-Castlepower-plant-switching-to-natural-gas/stories/201306240188 (last visited Dec. 23, 2019) (for units repowered using the existing boilers, all existing infrastructure is reused).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 93

Comment Excerpt:

3. Including Repowered Units Is Consistent with EPA's Economic Impact Analysis.

EPA's approach to its economic analysis weighs in favor of including repowered units in the Retirement Subcategory. For example, EPA's Economic Impact Analysis—one of the lynchpins of its Regulatory Impact Analysis—did not include any estimate of the costs or economic impacts of requiring units certified to repower to install BATW or FGD wastewater treatment technology that they would use for only three to five years. Instead, EPA removed those facilities from the industry profile for purposes of assessing the costs and economic impacts of the rule. *See* ERG 2019 Industry Change Memo at 5; Supplemental TDD at 3-4.

Requiring repowered facilities to incur the substantial costs of retrofitting technologies that will be used for far less than the standard 20-year depreciation period EPA used to assess annualized economic impacts[167] enlarges the Proposed Rule's economic impact, in real terms, for repowering facilities. If EPA elects not to include repowered facilities in the Retirement Subcategory, it must account for and explain why the economic impacts are justifiable.

EPA solicits comments on whether units that are being or will be repowered are unable to finance both the repowering retrofit and FGD wastewater and BATW technology upgrades that would be applicable to the unit prior to completion of the repowering. 84 Fed. Reg. at 64,641. The answer to that question depends on a variety of site-specific factors, including the borrowing power of the unit owner. But the question misses the most important point, i.e., that the realized costs of retrofitting a unit that will repower shortly thereafter are much higher than EPA calculated for the units that will not repower.

A permittee who is already planning to repower a unit or an entire facility could be required to spend hundreds of millions of dollars to retrofit units with BATW- and FGD wastewater-compliant technology only to operate them for a few years. The Agency examined cost implications of complying with the Proposed Rule under hypothetical unit retirement scenarios and concluded the costs they would have to recover would be far higher, in real terms, than the costs for units that were more likely to operate for the full 20-year amortization period EPA's annualized cost calculations assumed. See ERG, *Memorandum re: Steam Electric Effluent Guidelines Reconsideration – Evaluation of Potential Subcategorization Approaches,* EPA-HQ-OW-2009-0819-7911 (August 2019) ("ERG, EPA-HQ-OW-2009-0819-7911"). ERG's analysis applies equally to repowering units, which for cost purposes are no different than retiring units.

Even if a repowered unit could afford to pay off financing related to the abandoned equipment, however, it is an imprudent use of resources. In many cases, ratepayers would absorb these additional costs for equipment that will be mothballed a few years after it is put into service.

[167] See 84 Fed. Reg. at 64,640 ("Cost estimates for this proposal assume that facilities will amortize capital and O&M costs across the 20-year life of the technologies…").

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 94

Comment Excerpt:

4. Including Repowered Units Is Consistent with the CCR Rule.

One of EPA's reasons for proposing the Retirement Subcategory is to "ensure that facilities could make better use of the CCR rule's alternative closure provision, by which an unlined surface impoundment could continue to receive waste and complete closure by 2028." 84 Fed. Reg. at 64,641. The Agency notes that "facilities may have to cease receiving waste well in advance of that date" but "a 2028 date ensures that the ELG will not restrict the use of this alternative closure provision regardless of when a facility ultimately ceases receipt of waste." Id.

The CCR rule's current alternative closure provisions allow units otherwise required to close to continue receiving CCR under certain circumstances. For a CCR surface impoundment that is 40 acres or less, if the permittee agrees to cease operation of the coal-fired boiler, the impoundment is permitted to continue receiving CCR, but must complete closure by October 17, 2023. 40 C.F.R. § 257.103(b)(2). If the surface impoundment is larger than 40 acres and the permittee agrees to cease operation of the boiler, the impoundment may continue receiving CCR, but it must complete closure by October 17, 2028. 40 C.F.R. § 257.103(b)(3).[168]

UWAG applauds EPA's effort to harmonize the ELG and CCR rules in order to not foreclose use of the CCR alternative closure provisions. The Retirement Subcategory is a critical feature of the Proposed Rule and the eight-year deadline provides the necessary time for the industry to transition the nationwide fleet in light of the ELG and CCR rules.

The CCR rule, however, is no reason to exclude repowered units from the Retirement Subcategory. Nothing in the CCR rule prevents permittees from using the alternative closure provisions for units that are being repowered with a non-coal fuel source. In fact, repowering is entirely consistent with the intent of the CCR rule that permittees cease using *coal-fired* boilers. See 80 Fed. Reg. 21,302, 21,340-41 (Apr. 17, 2015) ("These requirements also do not apply to fly ash, bottom ash, boiler slag, and flue gas desulfurization materials, generated primarily from the combustion of fuels (including other fossil fuels) *other than coal*…. Fuel mixtures that *contain less than 50% coal* are not considered to be CCR, but other fossil fuel wastes…. Similarly, EPA determined that *regulating natural gas combustion wastes is not warranted* because the burning of natural gas produces virtually no solid waste."); 40 C.F.R. § 257.103(b)(3) ("…the *coal-fired* boiler must cease operation, and the CCR surface impoundment must complete closure…"). By definition, if a unit is repowered using only natural gas, it is no longer a coal-fired unit, the former coal-fired unit has ceased operation, and the repowered unit does not produce CCR.

5. Some Units are CCR Compliant and Have Not Yet Retrofitted BATW Systems.

Units that may repower have not necessarily retrofitted technologies that will comply with the ELGs because of the CCR rule. It is not the case, as the Proposal suggests in several locations, that all coal-fired facilities are already being required to retrofit BATW recirculating systems to replace CCR ponds forced to close by the CCR rule. For example, the Proposal states: "[f]lexibility for facilities to comply with BAT limitations for BA transport water beyond 2023 is not necessary because the process changes should already have occurred due to CCR rule requirements." 84 Fed. Reg. at 64,641. This is inaccurate. There are coal-fired facilities that are CCR rule-compliant without having to retrofit additional BATW technologies. For instance, some coal-fired units with lined ponds[169] comply with the CCR rule, recirculate part of their BATW, and meet the current ELG TSS and oil and grease limits. Also, many systems have dewatering bins that discharge to treatment systems, including settling basins not considered CCR ponds. These types of systems are CCR-compliant without requiring any retrofitting

[168] EPA is considering changes to the CCR rule, including revisions to the initiation of closure deadlines for unlined CCR surface impoundments and for units that failed the aquifer location restriction. See 84 Fed. Reg. 65,941, 65,942 (Dec. 2, 2019).

[169] Some facilities have clay-lined ponds that met the criteria of "lined" ponds under the 2015 CCR rule and, therefore, were not subject to closure. 40 C.F.R. § 257.71(a)(1)(i). In August 2018, however, the D.C. Circuit Court of Appeals vacated this provision. *Utility Solid Waste Activities Group v. EPA,* 901 F. 3d 414 (D.C. Cir. 2018). EPA is planning to propose a rule that would "provide a mechanism in which unlined surface impoundments meeting strict criteria would be allowed to continue to operate." OMB, *Fall 2019 Unified Regulatory Agenda: Hazardous and Solid Waste Management System: Disposal of CCR; A Holistic Approach to Closure Part B: Alternate Demonstration for Unlined Surface Impoundments; Implementation of Closure; Legacy Units* (RIN 2050-AH11), https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201910&RIN=2050-AH11 (last visited Dec. 31, 2019). Therefore, some facilities with clay-lined ponds are awaiting this rule and have not retrofitted BATW handling.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 95

Comment Excerpt:

Facilities that fall into this category will need time to plan, design, procure, construct, and optimize new treatment systems to comply with the Proposed Rule.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 96

Comment Excerpt:

B. Permittees May Need Approximately Eight Years to Complete Unit Retirement or Repowering.

EPA solicits comment on whether December 31, 2028, is the appropriate target date for the Retirement Subcategory. 84 Fed. Reg. at 64,641. UWAG supports the December 31, 2028 date so long as the final rule's effective date occurs by June 30, 2020. Otherwise, the Retirement Subcategory date should be eight years from the effective date of the rule. The eight-year period is necessary because it allows (1) two years for permittees to analyze the final rule, make a decision about whether to retrofit, retire, or repower their units, and secure approvals from public utility commissions ("PUCs") and/or independent systems operators ("ISOs"); and (2) approximately six years to complete new transmission and/or generation projects to support retirement or repowering decisions. This time period is necessary for orderly decision-making during a time of intense transition within the industry. It would give permittees time to decide whether to retrofit, retire, or repower their units after considering market factors, the impact of other regulations, and the estimated costs of compliance with the final rule.

EPA gives permitting authorities the ability to set applicability dates that are "as soon as possible" after November 1, 2020, after considering such factors as "[t]ime to expeditiously plan (including to raise capital), design, procure, and install equipment … Changes being made or planned at the plant in response [to Clean Air Act (CAA) or Resource Conservation and Recovery (RCRA) regulations] … [and] [o]ther factors as appropriate." 40 C.F.R. § 423.11(t); see also 84 Fed. Reg. at 64,665. EPA's delegation of authority acknowledges that there are many factors that affect permittees' ability to decommission, construct, or modify units. The decision of whether to retire or repower a unit requires permittees to evaluate a variety of factors, including the factors EPA acknowledges as appropriate to consider in setting applicability dates. Thus, EPA should consider the discussion below in that context and allow approximately eight years after the final rule's effective date for permittees to retire or repower their units.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 97

Comment Excerpt:

1. Analysis of the Final Rule and Gathering Data to Make Informed Decisions About Whether to Retrofit, Retire, or Repower Units Could Take Approximately Two Years.

While some wastewater characterization, pilot studies, and preliminary technology evaluations can be done before EPA publishes the final rule, the ultimate economics driven by the details of the final rule will control the decision whether to retrofit (i.e., install new technology to comply with the final rule), retire, or repower units. Permittees will need to analyze the final rule and a myriad of other considerations before they can make a final decision about whether to retrofit, retire, or repower their units. These considerations include business decisions related to financing, facility changes required by other rules, and other factors that bear on the decision to retrofit or retire units.

In addition to the time necessary to fully analyze and understand the final rule, permittees will need time to gather and analyze detailed information about compliant technologies, beyond what could be assessed preliminarily while EPA was reconsidering the rule. Tasks related to choosing the appropriate technologies may include those listed below.

- Determine applicable final rule requirements and gather initial information on candidate technologies for each affected wastestream. While evaluating applicable final requirements may sound straightforward, the comingling of existing wastestreams and other plant-specific process configurations may require more detailed analysis of potential compliance options.
- Perform evaluations to ensure that all wastestreams are properly mapped on an up-to-date diagram that will serve as the baseline for planning retrofits (may also require additional flow and mass balance studies).
- Evaluate potential water use reductions and recycle options.
- Develop a final list of all candidate technologies and their costs for each facility.
- Develop an RFP for each technology and send it to appropriate vendors.

Permittees also will need time to consider how to obtain appropriate financing, including, but not limited to, resolving the issues raised below.

- Analyze the impacts of the final rule on their operations and conduct economic assessments—permittees cannot commit themselves to capital expenditures until legal requirements are settled.
- Run and analyze the results of system planning models for various combinations of possible retrofits and unit retirements.
    - If necessary, take the required steps to secure PSC approval for costs, which requires time to coordinate meetings and hearings.
    - Determine an appropriate scheduling of debt obligations in light of existing debt obligations and commitments for planned construction at the facility or other facilities.

In addition, conceptual retrofit design will take months.[170] When considering retrofit design, permittees will need time to complete several tasks, including, but not limited to, those listed below.

- Determine necessary O&M, O&M frequency, and O&M costs for each candidate technology.
- Evaluate proposals from vendors and develop total cost estimates for each candidate technology and all related new infrastructure (e.g., balance-of-plant costs, new landfill space, new control systems, etc.).
- Determine life cycle analysis, including O&M costs, for technology options per wastestream (e.g., dry handling of bottom ash vs. MDS vs. remote RMDS).
- Conduct unit-by-unit cost/benefit analysis to determine whether to retrofit or retire the units.
- Develop conceptual design, considering specifics of the units being retrofitted (e.g., maximum capacity, heat rate, etc.).

- Determine permitting requirements for each retrofit and develop timelines for securing necessary permits/permit modifications.
- Make the technology selection for each wastestream in consultation with all appropriate people within the company.
- Align all connections and tie-ins to the existing equipment in coordination with planned unit major outages that generally occur every three years.

Permittees also will need time to consider the changes being made at their facilities to comply with other regulations like the Clean Water Act § 316(b) Rule (the "§ 316(b) rule"), the CCR rule, and the Affordable Clean Energy ("ACE") rule. For example, permittees will need to:

- analyze the actions and costs required to comply with the § 316(b) rule and how those actions may affect retrofits and/or facility retirement or repowering decisions;
- in light of proposed changes to the CCR rule, consider how the rule's deadlines and substantive requirements may affect ELG compliance; and/or
- for the ACE rule, consider the "remaining useful life" analysis of units.[171]

Finally, permittees will need time to consider other factors that will affect their decision whether to retrofit their facilities to comply with the final rule, retire, or repower them. A few of those factors are:

- the time required, and the schedule, for necessary corporate actions (e.g., management and Board of Directors' approvals, resolutions, etc.);
- whether retrofitting the affected units at the facility is likely to cause any grid reliability problems, including short-term ones;
- the impact of managing multiple retrofits at multiple facilities within the same general time period;
- the time required to acquire any additional real property needed for retrofits;
- any commitments (through individual settlements with EPA or the states, for example) to reduce the capacity of, or shut down, facilities affected by the final rule; and/or
- any backlog of NPDES permitting for states in which permittees operate and the general permitting requirements and their timing (e.g., public notice, public comments/hearings, etc.).

As the considerations above illustrate, permittees will require time after EPA publishes the final rule not only to analyze it, but to make informed decisions about their next steps. This period could take approximately two years.

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[170] Southern Company, Comment Letter on Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-HQ-OW-2009-0819- 4379, 149 (Sept. 19, 2013) ("Given the number of plants that will be impacted [by the 2013 proposed ELG rule] and the demand on vendors and contractors, we believe that 12-18 months will be needed for conceptual design.").
[171] See 84 Fed. Reg. 32,520, 32,535 (July 8, 2019) ("Indeed, Congress has expressly provided that the EPA must permit states to take into consideration a source's remaining useful life, among other factors, when applying a standard of performance to a particular source.")

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Commenter Affiliation: Utility Water Act Group (UWAG)
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Comment Excerpt Number: 99

Comment Excerpt:

3. Industry Examples Support the Need to Provide Permittees approximately Eight Years to Retire or Repower Units.

a. Louisville Gas and Electric Company and Kentucky Utilities Company, Cane Run Generating Station

In early 2009, EPA started a review of primary national air quality standards ("NAAQS") for sulfur oxides (SO_2). See 74 Fed. Reg. 18,573 (Apr. 23, 2009). This review led to a proposed rule to revise the primary NAAQS for SO2. 74 Fed. Reg. 64,810 (Dec. 8, 2009).

Attempting to get ahead of anticipated regulatory changes, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") conducted an analysis indicating that the least costly way to comply with the proposed rule would be to replace the coal-fired units at their Cane Run Generating Station ("Cane Run") in Louisville, Kentucky, with natural gas "combined cycle turbines" ("CCGT"). They also conducted siting studies that suggested Cane Run was the best location for a self-build option.

In December 2010, LG&E and KU issued an RFP seeking solutions to meet their electric energy and capacity requirements at Cane Run by 2016.[176] At the conclusion of the RFP processes, the utilities determined, in part, that replacing Cane Run coal-fired generation with 640 MW of natural gas powered generation was the best alternative to bring the Cane Run facilities into compliance with EPA regulations. LG&E and KU CPCN Application at 4-5. LG&E and KU further evaluated the effects of various EPA regulations on their generation facilities and their proposed plans to meet their energy requirements, including consideration of the replacement of the Cane Run coal unit with a CCGT, in reports filed with the Kentucky Public Service Commission (the "Kentucky Commission") in 2011.[177]

On September 15, 2011, the utilities filed a joint application requesting regulatory approvals to, in part, construct a 640 MW CCGT to replace coal-fired generation facilities at Cane Run. Id. at 1. LG&E and KU implemented this plan to comply not only with changing EPA regulations regarding NAAQS, but also the proposed Cross-State Air Pollution Rule ("CSAPR") and a proposed rule aimed at reducing hazardous air pollutants (the MATS rule), each of which were determined to make continued coal operations at Cane Run infeasible.[178]

The Kentucky Commission approved the utilities' application on May 31, 2012, following a public hearing, a hearing on the merits, and post-hearing briefing. *See generally* Order, *In re: LG&E and KU Cane Run* (May 31, 2012). The Cane Run CCGT reached commercial operation in June 2015, approximately five years following the utilities' initial consideration of the project.

History of Cane Run Plant, LGE-KU.COM, https://lge-ku.com/canerun/history (last accessed Dec. 16, 2019).

b. Georgia Power Company, McDonough Plant

In 2007, Georgia Power Company ("Georgia Power") sought regulatory approval from the Georgia Public Service Commission ("GA PSC") to construct a combined cycle generation unit at Plant McDonough, near Atlanta, Georgia.[179] Georgia Power implemented its plan to meet future resource needs, which included the necessary replacement of the Plant McDonough coal units. Georgia Power Application at 10-13. In its 2004 IRP, Georgia Power investigated various generation and transmission challenges facing the Northeast Georgia region and developed a strategy for expansion, including the proposed addition of gas-fired facilities. Georgia Power Application at 11 (The GA PSC approved Georgia Power's 2004 IRP in July 2004.). Georgia Power issued an RFP for the construction of the proposed project in 2006 and submitted a revised information filing, including its evaluation of decertifying the Plant McDonough coal units and cost benefits of replacing the coal-fired capacity with gas-fueled generation, to the GA PSC in January 2007. Id. at 19, 44, 47-48.

Georgia Power filed its application seeking the certification of combined cycle units and related decertification of its coal units at Plant McDonough on January 31, 2007. *See generally id.* The GA PSC approved the application on September 14, 2007. Certification Order Adopting Stipulation, *In re: Georgia Power McDonough* (Sept. 14, 2007). All of the Plant McDonough natural-gas fired units reached commercial operation by October 2012, approximately six years following Georgia Power's initial RFP and approximately eight years following Georgia Power's 2004 IRP.[180]

c. Colorado Electric Utility Company, Pueblo Airport Generating Station

In 2013, Colorado Electric Utility Company (d/b/a Black Hills Energy ("Black Hills"))[181] sought regulatory approval to construct a natural gas-powered electric generating plant at Black Hills' Pueblo Airport Generation Station ("PAGS") to replace its coal-fired Clark Station generating unit in Cannon City, Colorado.[182] Black Hills implemented its plan to replace the coal-fired facilities with natural gas generation facilities in response to Colorado's Clean Air-Clean Jobs Act ("CACJA"), requiring utilities operating coal-fired electric generation units located in Colorado to implement an emission reduction plan on or before August 15, 2010. Phase I Decision No. C14-0007 at 18, *In re: Black Hills PAGS* (Dec. 17, 2013).

On August 13, 2010, in compliance with the CACJA, Black Hills filed an emission reduction plan proposing to retire its two units at Clark Station and replace that capacity with a gas-fired unit to be constructed at PAGS. Id at 19. The Public Utilities Commission of Colorado (the "Colorado Commission") approved Black Hills' emission reduction plan on December 15, 2010. Id. Subsequently, in 2011, Black Hills filed an application seeking a CPCN to construct a 92 MW facility at PAGS; the Colorado Commission denied Black Hills' application on the basis that Black Hills failed to prove that there was a need to construct 92 MW of facility capacity. Id. at 20. Black Hills refiled its application seeking a CPCN for the development and ownership of a proposed 40 MW generation facility located at PAGS on April 30, 2013. *See generally* Black

Hills' Verified Application. The Colorado Commission approved the application, pursuant to a settlement agreement reached in the docket, on December 17, 2013. *See generally* Phase I Decision No. C14-0007, *In re: Black Hills PAGS* (Dec. 17, 2013). The PAGS 40 MW natural gas-fired turbine reached commercial operation on December 29, 2016, approximately six years following Black Hills's filing of its 2010 emission reduction plan proposing to replace Clark Station coal units with gas-fired units.[183]

d. Public Service Company of Colorado, Cherokee Generating Station

During the Spring of 2010, shortly after Colorado passed the CACJA on April 19, 2010, the Public Service Company of Colorado ("Public Service") started identifying coal units that it would need to address in an emissions reduction plan[184] required by CACJA. On August 13, 2010, Public Service submitted its Emission Reduction Plan to the Colorado Commission. Final Order Addressing Emission Reduction Plan, Decision No. C10-1328 at 4, *In re: Public Service ERP* (Dec. 9, 2010). The Emission Reduction Plan proposed several changes at the Cherokee Generating Station near Denver, CO, including retirement of several coal-fired units, replacement with natural gas-fired units, and repowering a coal-fired unit with natural gas. Emissions Reduction Plan at 8-9.

In its plan, Public Service highlighted several reasons why it would be critical to sequence the coal-fired unit retirements, replacements, and/or retrofits. Emissions Reduction Plan at 32. For example, because of engineering construction schedules and space restrictions at the Cherokee site, construction of natural-gas fired units would need to be staggered to replace retiring units. Id. To meet transmission reliability requirements, the earliest natural-gas fired units could start operation would be Spring 2014, when a new gas pipeline could be built to supply gas to Cherokee. Id. at 33. Finally, Public Service stated that sequencing was important to ensure expenditures were spread out over several years and to better mitigate annual rate impacts. Id.

After extensive public comments and hearings, the Colorado Commission modified and approved the Emission Reduction Plan, ordering, in part, that three coal-fired units be retired by 2015, another coal-fired unit be converted to a natural-gas fired unit by the end of 2017, and Public Service be granted a presumption of need for additional natural-gas fired units in a future application. Final Order Addressing Emission Reduction Plan, at 84-85.

In accordance with its Emissions Reduction Plan and the Colorado Commissions' decision, Public Service retired a coal-fired unit in 2011; retired another coal-fired unit in 2012; retired a third coal-fired unit in 2015; constructed and put into operation three natural-gas fired, combined cycle units in August 2015; and repowered the final coal-fired unit in September 2017.[185] In other words, Public Service completed the final phase of the Emissions Reduction Plan, with respect to the Cherokee Generating Station, almost seven and a half years after it started assessing its options for complying with the CACJA.

e. Alliant Energy, Riverside Energy Center Expansion Project

In November 2013, Alliant Energy (d/b/a Wisconsin Power and Light Company ("WPL")) began a study to assess the feasibility of new generating resource options because it planned to retire several coal-fired power plants.[186] The feasibility study looked at market options and analyzed which options could satisfy MISO's load requirements. In June 2014, WPL issued an RFP and received and analyzed over 30 proposals. As a result, WPL decided that a two-on-one, natural gas-fired, combined-cycle generating facility that could produce approximately 650 MW of electricity was appropriate. WPL Application at 8-9. On April 24, 2015, WPL submitted an application for a CPCN from the Public Service Commission of Wisconsin (the "Wisconsin PSC"). One year later, on May 6, 2016, the Wisconsin PSC approved WPL's CPCN application. Final Decision, *In re: WPL Riverside* (May 6, 2016).

WPL started construction on April 11, 2017.[187] In addition to obtaining the CPCN, WPL has been working for years to obtain all of the necessary federal and state permits to allow it to construct and operate the project. WPL Letter at 13-16. As of the end of September 2019, WPL had completed 96 percent of construction and still needed to obtain several permits before operation starts. Id. at 4. WPL anticipates completion by May 2020,[188] six and a half years after it started its feasibility study.

f. Virginia Electric and Power Company, Surry-Skiffes CreekWhealton Project

In its 2011 Integrated Resource Plan, Virginia Electric and Power Company (d/b/a Dominion Virginia Power ("Dominion")) identified several coal-fired generation units that it would need to retire between 2014 and 2022 because of their old age or other regulatory requirements (e.g., the MATS Rule).[189] To meet mandatory NERC reliability criteria after retiring these units, Dominion proposed a project to construct a 500kV aerial transmission line and switching station and to upgrade an existing transmission right-of-way to connect the Surry Nuclear Power Plant with a substation on the Yorktown Peninsula. Dominion Application at 5- 6. On June 11, 2012, Dominion submitted an application for a CPCN to the Virginia State Corporation Commission (the "SCC"). Id. at 1-4.

Although the SCC issued an order granting Dominion's application on November 26, 2013, litigation ensued, and the SCC was not able to issue a final order until June 5, 2015, after the Virginia Supreme Court remanded the case to the SCC. Order at 2-3, *In re: Dominion SurrySkiffes Creek* (June 5, 2015).

Even after the June 2015 SCC order, Dominion was not able to begin construction on all segments of the project because it still needed certain permits. For example, Dominion needed a Special Use Permit and approval for its site plan work at the switching station segment of the project from James City County ("JCC").[190] After contentious proceedings regarding both authorizations, JCC issued the Special Use Permit on July 11, 2017, and gave Dominion final approval for its site plan work for the switching station portion of the project on September 19, 2017.

In addition, Dominion needed two permits for critical segments of the project from the U.S. Army Corps of Engineers (the "Corps").[191] Dominion submitted a permit application to the Corps in August, 2013. June 2015 Update at 3. Almost four years later, on July 3, 2017, the Corps issued a final permit to Dominion under § 404 of the Clean Water Act and § 10 of the Rivers and Harbors Act. October 2017 Update at 4. Just a few days later—on July 12, 2017— federal litigation ensued over the permit. Id. at 3. Despite ongoing federal litigation, Dominion energized the project on February 26, 2019,[192] almost eight years after it identified the need for the project in its 2011 IRP.

g. Kentucky Power Company, Big Sandy Plant

In response to new CAA rules (i.e., CSAPR and the MATS rule) and under a Consent Decree,[193] Kentucky Power Company ("Kentucky Power"), a wholly owned subsidiary of American Electric Power, submitted to the Kentucky Commission on December 5, 2011, an application for approval to retire one unit and retrofit another with air pollution control equipment at its Big Sandy Plant by the end of 2015.[194] Sierra Club intervened in the proceeding, arguing that Kentucky Power should pursue "lower cost market, natural gas, energy efficiency, and renewable energy resources" in lieu of its proposed plan.[195] In May 2012, Kentucky Power requested, and the Kentucky Commission granted, to withdraw its application to "reevaluate alternatives" and environmental regulations.[196] Kentucky Power ultimately decided to retire one unit at Big Sandy and repower the other to burn natural gas.[197] Although the MATS rule required compliance by April 16, 2015, Kentucky Power was able to get extensions to complete its retirement and repowering plans.[198] One unit was retired on June 1, 2015, and the other went online burning natural gas on May 30, 2016.199 The retirement and repowering project was completed over eight and a half years after the Consent Decree was issued and over five and a half years after Kentucky Power submitted an initial proposal to the Kentucky Commission.

These industry examples illustrate the unique circumstances and challenges facilities face when attempting to implement retirement and/or repowering projects. Below is a summary of the time each of the facilities described above needed to retire or repower their units, or connect to replacement power:

Company	Facility	Time Required
LG&E and KU	Cane Rune	Approximately 5 years
Georgia Power	Plant McDonough	Approximately 8 years
Black Hills	PAGS	Approximately 6 years
Public Service	Cherokee Generating Station	Approximately 7.5 years
WPL	Riverside Energy Center Expansion Project	Approximately 6.5 years
Dominion	Surry-Skiffes Creek-Whealton Project	Approximately 8 years
Kentucky Power	Big Sandy Plant	Approximately 8.6 years

For the reasons discussed above, analysis of the final rule and the decision to retrofit, retire, or repower existing facilities, and then implement that decision takes years. UWAG urges EPA to adopt the Retirement Subcategory in the final rule and allow permittees eight years to retire or repower units rather than retrofit their facilities with technology required to meet the proposed BATW and FGD wastewater requirements.

[176] Joint Application of Louisville Gas and Electric Co. and Kentucky Utilities Co., ….Vol. 1 at 4 (the "LG&E and KU CPCN Application"), *In re: Joint Application of Louisville Gas and Electric Co. and Kentucky Utilities Co. for a Certificate of Public Convenience and Necessity and Site Compatibility*

Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Co., LLC in LaGrange, Ky., No. 2011-00375 (Ky. Pub. Serv. Comm'n Sept. 15, 2011) (*"In re: LG&E and KU Cane Run"*).

[177] LG&E and KU CPCN Application at 2-3 (The companies submitted a Compliance Plan evaluating the effects of EPA regulation on each of the companies' coal-fired steam generating units in June 2011 and an Integrated Source Resource Plan providing detailed summaries of the companies' plans to meet their future energy requirements within their service areas in April 2011.); see The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Co. and Kentucky Utilities Co., Volume 1 at 8- 78, *In re: LG&E and KU Cane Run* (Apr. 21, 2011).

[178] Id. at 2 (In March 2011, the EPA issued the MATS rule aimed at reducing hazardous air pollutants from new and existing coal- and oil-fired electric utility steam generating units. In August 2011, the EPA issued CSAPR that provided limited allowances for NOx and SO2 emission starting in 2012. Finally, EPA's NAAQS rule was introduced to further restrict NOx and SO2 emissions starting in 2016 and 2017.).

[179] Application of Georgia Power Co. (the "Georgia Power Application") at 9-10, *In re: Georgia Power Co.'s Application for Certification of Units 4, 5, and 6 at Plant McDonough and Decertification of Units 1 and 2 at Plant McDonough,* No. 24506-U (Ga. Pub. Serv. Comm'n Jan. 31, 2007) (*"In re: Georgia Power McDonough"*).

[180] Final – McDonough Construction Monitoring Report of Accion Group, Inc. on Georgia Power Co.'s Construction Activities Concerning Plan McDonough Units 4, 5, and 6, at 2 n.1, *In re: Georgia Power McDonough* (Aug. 26, 2014).

[181] "Investor-owned utilities are for-profit corporations that are regulated by the Colorado Public Utilities Commission ("PUC"). Colorado has two investor-owned electric utilities – Black Hills Energy and Public Service Company of Colorado, known as Xcel Energy." Colorado Energy Office, *Electric Utilities*, https://www.colorado.gov/pacific/energyoffice/electric-utilities) (last visited Dec. 20, 2019).

[182] Verified Application of Black Hills/Colorado Electric Utility Co. ("Black Hills' Application") at 1, *In re: Application of Black Hills/Colorado Electric Utility Co., LP for a Certificate of Public Convenience and Necessity to Construct a Power Plant Consisting of a 40 MW Simple Cycle Combustion Turbine and Associated Balance of Plant Pursuant to Commission Decision No. C12-1434, No. 13A0446-E* (Pub. Utils. Comm'n of Colo. Apr. 30, 2013) (*"In re: Black Hills PAGS"*)

[183] Black Hills Corp., *Black Hills Corp. Reports First Quarter 2017 Results,* BLACKHILLSCORP.COM (May 3, 2017), http://ir.blackhillscorp.com/QuarterlyEarnings/Index?KeyGenPage=1073753054 (last visited Dec. 19, 2019); Phase I Decision No. C14-0007 at 19, *In re: Black Hills PAGS.*

[184] Clean Air-Clean Jobs Act Emissions Reduction Plan of Pub. Serv. Co. of Colo. (the "Emissions Reduction Plan") at 8-9, *In re: Commission Consideration of Pub. Serv. Co. of Colo.'s Plan in Compliance with House Bill 10-1365, "Clean Air Clean Jobs Act,"* No. 10M-245E (Pub. Utils. Comm'n of Colo. Aug. 13, 2010) (*"In re: Public Service ERP"*).

[185] 2016 Electric Resource Plan of Pub. Serv. Co. of Colo., Vol. 1 at 1-13, 1-24, CPUC Proceeding No. 16A-0396E (Pub. Utils. Comm'n of Colo. May 27, 2016); see also Aldo Svaldi, *Coal's future as a power source in Colorado flickering,* THE DENVER POST (Sept. 3, 2017), https://www.denverpost.com/2017/09/03/colorado-coal-future-xcel-energy/ (last visited Dec. 18, 2019).

[186] Application of Wisconsin Power and Light Co. (the "WPL Application") at 8-9, *In re: Application for a Certificate of Public Convenience and Necessity to Build an Approximately 650 Megawatt Natural Gas-Fueled Power Plant at its Riverside Energy Center Facility in the Town of Beloit, Rock County, Wis.,* No. 6680-CE-176 (Pub. Serv. Comm'n of Wis. Apr. 24 2015) (*"In re: WPL Riverside"*).

[187] Letter from Brian Penington, Manager Regulatory Affairs, WPL, to Steffany Powell Coker, Secretary to the Commission, Wisconsin PSC (the "WPL Letter") at 11, *In re: WPL Riverside* (Oct. 30, 2019).

[188] Brad Allen, *Alliant Plant Nearing Completion in Township,* Beloit Daily News (Oct. 18, 2019), https://www.beloitdailynews.com/local_news/20191018/alliant_plant_nearing_completion_in_township (last visited Jan. 19, 2020).

[189] Application of Virginia Electric and Power Co., Application No. 257 (the "Dominion Application"), Vol. I at 3-4, *In re Application of VEPCO d/b/a Dominion Virginia Power for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes CreekWhealton 230 kV Transmission Line, and Skiffes Creek 500 kV-230 kV-115 kV Switching Station,* No. PUE-2012-00029, (Va. State Corp. Comm'n June 11, 2012) (*"In re: Dominion Surry-Skiffes Creek"*).
[190] Update on Status of Certificated Project ("October 2017 Update") at 12, 14-15, *In re: Dominion Surry-Skiffes Creek* (Oct. 10, 2017).
[191] Update on Status of Certificated Project ("June 2015 Update") at 3, *In re: Dominion SurrySkiffes Creek* (June 19, 2015).
[192] Update on Status of Certificated Project at 16, *In re: Dominion Surry-Skiffes Creek* (Feb. 27, 2019).
[193] *United States v. Am. Elec. Power Serv. Corp.,* Civil Action C2-99-1250, 2007 U.S. Dist. LEXIS 104330 (S.D.N.Y. Oct. 9, 2007).
[194] *Application of Kentucky Power Co. at 6-7, In re: Application for Approval of its 2011 Environmental Compliance Plan, For Approval of Its Amended Environmental Cost Recovery Surcharge Tariff, and for the Grant of a Certificate of Public Convenience and Necessity for the Construction and Acquisition of Related Facilities,* No. 2011-00401 (Ky. Pub. Serv. Comm'n Dec. 5, 2011) (*"In re: Kentucky Power Big Sandy"*).
[195] Post Hearing Br. of T. Vierheller, et al. at p.3 of pdf file, *In re: Kentucky Power Big Sandy* (May 11, 2012).
[196] Order at 1, *In re: Kentucky Power Big Sandy* (May 31, 2012).
[197] Integrated Resource Planning Report of Kentucky Power Co. to the Kentucky Public Service Commission ("2013 IRP"), Vol. A at ES-1, *In re: Integrated Resource Planning Report of Kentucky Power Company to the Kentucky Public Service Commission,* No. 2013-00475 (Ky. Pub. Serv. Comm'n Dec. 20, 2013).
[198] Integrated Resource Planning Report of Kentucky Power Co. to the Kentucky Public Service Commission ("2016 IRP"), Vol. A at 63, *In re: Electronic 2016 Integrated Resource Planning Report of Kentucky Power Company to the Public Service Commission of Kentucky,* No. 2016-00413 (Ky. Pub. Serv. Comm'n Dec. 20, 2016).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 31

Comment Excerpt:

C. The Retirement Subcategory Would Ease the Industry's Transition to Other Fuels, Which is Already Well Underway.

NERC recently conducted a special reliability assessment to assess the potential implications of the changing generation resource mix on the reliability of North America's bulk power system ("BPS").[200] The BPS transformation is occurring due to growth in new natural gas, wind, and solar resources as older, coal-fired or nuclear power plants retire. NERC Special Reliability Assessment at p. v. NERC concluded "that generator retirements are occurring, disproportionately affecting large baseload, solid-fuel generation (coal and nuclear). If these retirements happen faster than the system can respond with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur." Id.; see also 84 Fed. Reg. at 64,640. As discussed above, independent system operators ("ISOs") could seek RMR agreements with generator owners if the ISOs determine "that a unit planning to retire is needed for reliability, and no other solutions are readily available within the specified time frame…." Id. at 22. The Retirement Subcategory would reduce concerns about overreliance on natural gas or renewables during the industry's transition period because coal-fired units would be allowed to operate a few additional years to help stabilize the grid.

The Retirement Subcategory also would promote investment in non-coal-fired units by providing some relief from unrecovered costs related to ELG retrofits. As the Agency points out, there is "potential for stranded assets where equipment would be purchased near the end of a facility's useful life and the public utility commission (PUC) would not allow cost recovery." 84 Fed. Reg. at 64,640.[201] There are "recent examples of PUCs rejecting cost recovery, which make the prospect of continued recovery after retirement less certain." Id. at 64,640.

[200] NERC Special Reliability Assessment at v.

[201] The concept of stranded assets or costs generally refers to "costs incurred by a utility which may not be recoverable under market-based retail competition. Examples include undepreciated generating facilities, deferred costs, and long-term contract costs." EIA Glossary, https://www.eia.gov/tools/glossary/index.php?id=S (last visited Dec. 17, 2019).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 100

Comment Excerpt:

C. The Retirement Subcategory Would Ease the Industry's Transition to Other Fuels, Which is Already Well Underway.

NERC recently conducted a special reliability assessment to assess the potential implications of the changing generation resource mix on the reliability of North America's bulk power system ("BPS").[200] The BPS transformation is occurring due to growth in new natural gas, wind, and solar resources as older, coal-fired or nuclear power plants retire. NERC Special Reliability Assessment at p. v. NERC concluded "that generator retirements are occurring, disproportionately affecting large baseload, solid-fuel generation (coal and nuclear). If these retirements happen faster than the system can respond with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur." Id.; see also 84 Fed. Reg. at 64,640. As discussed above, independent system operators ("ISOs") could seek RMR agreements with generator owners if the ISOs determine "that a unit planning to retire is needed for reliability, and no other solutions are readily available within the specified time frame…." Id. at 22. The Retirement Subcategory would reduce concerns about overreliance on natural gas or renewables during the industry's transition period because coal-fired units would be allowed to operate a few additional years to help stabilize the grid.

The Retirement Subcategory also would promote investment in non-coal-fired units by providing some relief from unrecovered costs related to ELG retrofits. As the Agency points out, there is "potential for stranded assets where equipment would be purchased near the end of a facility's useful life and the public utility commission (PUC) would not allow cost recovery." 84 Fed. Reg. at 64,640.[201] There are "recent examples of PUCs rejecting cost recovery, which make the prospect of continued recovery after retirement less certain." Id. at 64,640.

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[200] NERC Special Reliability Assessment at v.

[201] The concept of stranded assets or costs generally refers to "costs incurred by a utility which may not be recoverable under market-based retail competition. Examples include undepreciated generating facilities, deferred costs, and long-term contract costs." EIA Glossary, https://www.eia.gov/tools/glossary/index.php?id=S (last visited Dec. 17, 2019).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 101

Comment Excerpt:

XVI. EPA Should Allow Permittees to Submit Retirement or Repowering Certification Statements On or Before December 31, 2023.

EPA proposes that permittees seeking to include their units in the Retirement Subcategory must submit a certification statement, which would be "a one-time certification to the permitting authority … submitted *with the permit application, or where a permit has already been issued, by the as soon as possible date* determined under paragraph 423.11(t)…." Proposed § 423.19(f)(1) (emphasis added).

For all of the reasons described in Section XV.A, UWAG recommends that EPA amend the language in proposed § 423.19(f) to specifically include units that will be repowered.

UWAG also recommends that EPA change its proposed deadline for submitting the retirement or repowering certification. See Proposed § 423.19(f)(1). Permittees should be allowed to certify retirement or repowering of units on or before December 31, 2023, regardless of permit application or renewal schedules.[202] For all the reasons described in Section XV.B.1, permittees will need time after the final rule's effective date to make retirement or repowering decisions. Also, allowing permittees to certify retirement or repowering on or before December 31, 2023 simplifies the timing requirement and increases regulatory certainty.

Under EPA's proposed deadline, many facilities will be disadvantaged. If a company needs to submit a renewal application soon after the final rule's effective date, it may not have adequate time to analyze the impact of the rule on its units and its system. For instance, if the permit application is due one month after the effective date of the rule, the permittee will have only 90 days (assuming the rule is effective 60 days after publication) to analyze the rule and run system planning models. In contrast, a permittee whose application is due three years after the final rule's effective date has much more time to weigh the options. Thus, for consistency and simplicity, permittees should be able to submit their certifications on or before December 31, 2023, regardless of permit application or renewal schedules.

In addition, as described in Section XVIII, regulated utilities cannot certify retirement or repowering without permission from their state utility commissions. Therefore, allowing permittees to certify retirement or repowering on or before December 31, 2023 gives those permittees that are regulated the additional time necessary to submit IRPs and obtain the necessary state utility commission approvals.

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[202] UWAG recommends this be a "no later than" date as some permittees may choose to submit certifications sooner than December 31, 2023.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 10

Comment Excerpt:

NRECA supports the agency's proposed retirement subcategory for both easing and supporting the transition to alternative generation and for not expecting a plant at the end of its coal-fired generating life to make significant new capital investment. This proposal will ease the steam electric sector's transition to other fuels and will allow resources to be directed to such alternatives.

NRECA agrees that eight years is generally a reasonable time for a unit to retire or repower. Every project is different and multiple external factors such as uncertainty over other regulatory requirements, required permission and permits, and even weather will affect the ultimate timeline. Still, based on industry estimates (1) analyzing and selecting an option (e.g., invest in new pollution control equipment, repower, retire) can take about two years; (2) construction of new transmission and/or generation can take approximately six additional years. We are concerned, however, that setting a date certain, in this case December 31, 2028, could be problematic if EPA is delayed in finalizing this proposal. NRECA recommends EPA set a date eight years from the effective date of the final ELG rule.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)

Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 11

Comment Excerpt:

Similarly, NRECA recommends EPA provide two years from the effective date of the final rule for a plant to certify retirement (or repowering) both to reflect the two years EPA estimated to justify the December 2028 date and to avoid disadvantaging plants based on their NPDES renewal schedule.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 12

Comment Excerpt:

Finally, NRECA recommends EPA require a certified letter as sufficient to bind the entity submitting a certification; additional documentation (e.g. the most recent Integrated Resource Planning report (IRP) or a boiler cessation certification) is unnecessary and creates an additional regulatory burden with no commensurate regulatory benefit. Requiring a plant surrender the permit or license to generate electricity is not only unnecessary, but also would adversely affect gas-fired units co-located with retiring coal units.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 13

Comment Excerpt:

NRECA also urges the agency to expand the retirement subcategory to include plants that will repower in addition to those decommissioning. Repowering eliminates pollutants derived from coal as decommissioning does, so would achieve a similar environmental outcome. Repowering is not always viable, but where it is, the option may be more cost effective and less expensive than decommissioning one unit and constructing another. Similarly, we encourage EPA to revise the definition of “retired from service” to include repowered units as they are retired from service burning coal. Expanding the subcategory and definition to include units that repower is also consistent with the recent CCR proposal and would reduce complication and burden for plants subject to both the ELG and CCR rules.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 14

Comment Excerpt:

NRECA also urges the agency to expand the retirement subcategory to include plants that will repower in addition to those decommissioning. Repowering eliminates pollutants derived from coal as decommissioning does, so would achieve a similar environmental outcome. Repowering is not always viable, but where it is, the option may be more cost effective and less expensive than decommissioning one unit and constructing another. Similarly, we encourage EPA to revise the definition of "retired from service" to include repowered units as they are retired from service burning coal. Expanding the subcategory and definition to include units that repower is also consistent with the recent CCR proposal and would reduce complication and burden for plants subject to both the ELG and CCR rules.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 102

Comment Excerpt:

XVII. The Retirement Subcategory Certification Statement Should Require Only a Certified Letter from the Permittee.

EPA proposes that permittees seeking to include their units in the Retirement Subcategory must submit their most recent IRPs, a boiler cessation certification under the CCR Rule, or other legally binding support that their units will be retired by 2028, as well as a certification statement. Proposed § 423.19(f)(2). UWAG urges EPA to require only a certified letter signed by a responsible corporate officer in order to qualify a unit for the Retirement Subcategory.[203]

The permittee would be required to certify that it will retire (or repower) a unit by submitting to the permitting authority a certification statement that it will do so. The certification would be binding under the NPDES rules because it would be submitted in connection with an initial or renewal permit application, a modification of a current permit, or an update to a pending permit application. If a permittee is a corporation, it must submit its permit applications to NPDES permitting authorities, or any other information requested by permitting authorities, with a signature from a "responsible corporate officer,"[204] including a mandatory certification statement. See 40 C.F.R. § 122.22. If the permittee is a municipality, state, federal, or other public agency, it must submit its application or additional information with a signature from a "principal executive officer or ranking elected official," along with the same certification statement. Id.

The signatures of these individuals and the certification statements are enough, on their own, to legally bind the entities submitting application documents or information related to a pending application or existing permit. EPA's proposal to require other documentary evidence with the proposed initial certification statement is unnecessary to achieve the goal sought by the Proposed Rule (i.e., to legally bind the permittee) and unreasonably increases the burden on permittees.

[203] UWAG's recommendation is consistent with the CCR rule's alternative closure requirements for "[p]ermanent cessation of a coal-fired boiler(s) by a date certain." 40 C.F.R. § 257.103(b)(1). In fact, the only initial notification requirement for permittees seeking to abide by the alternative closure requirements is that they "prepare and place in the facility's operating record a notification of intent to comply" with them within six months of becoming subject to closure requirements. § 257.103(c). Also, the cooling water intake structures rule for existing facilities (known as the § 316(b) rule) contains a very simple certification requirement for exemptions for planned retirements. See § 122.21(r)(ii). Permittees that planned to retire their facilities before their then-current permit expired did not need to comply with substantive portions of the rule. § 122.21(r)(ii)(F). Permittees that planned to retire their facilities within one permit cycle after their then-current permit expired would not be subject to the substantive portions of the rule, so long as they signed a certified statement specifying the facility's last operating date. § 122.21(r)(ii)(G).
[204] 40 C.F.R. § 122.22(a)(1) ("a responsible corporate officer" means: "(i) A president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision-making functions for the corporation, or (ii) the manager of one or more manufacturing, production, or operating facilities, provided, the manager is authorized to make management decisions which govern the operation of the regulated facility…").

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 124

Comment Excerpt:

F. Including Repowering Units in the Retirement Subcategory is Important to Producing an Economically Achievable Rule.

As noted earlier in these comments, EPA has not assessed the economic impact of its Proposal to units that will repower by December 31, 2028. Instead, EPA removed from the industry profile 26 plants (43 units) that announced by October 2018 that they would *repower* with a non-coal fuel on or before December 31, 2028. ERG 2019 Industry Change Memo at 5-6. EPA identified another six units at two plants that announced repowering plans after the October 2018 cut-off. Id., Table 3 at 10.

EPA properly understood that units repowering with a non-coal fuel would no longer produce either BATW or FGD wastewater. But some of those units will not be repowered until December 2028, so they will generate BATW and FGD wastewater that will need to comply with any relevant ELGs that become applicable to those waste streams *before* December 2028. For this reason, as discussed in Section XV, UWAG urges EPA to apply its proposed December 31, 2028 deadline to facilities certifying to retire and repower.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 125

Comment Excerpt:

But if EPA elects to apply earlier deadlines to repowered facilities, the Agency must consider the costs and economic impacts of that approach. The current deadlines would require repowering facilities to shoulder the substantial costs of installing BATW and FGD wastewater technology that they will use for only a fraction of the 20-year depreciation period EPA uses for purposes of calculating annualized capital costs. As EPA's analysis of the actual costs for retiring facilities shows, those annualized costs for facilities in this situation are far higher than the costs realized by facilities that are able to use the technology for the intended period of time. See ERG, EPA-HQ-OW-2009-0819-7911 at 3-4.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 98

Comment Excerpt:

2. Construction of New Transmission and/or Generation Projects May Take Approximately Six Additional Years.

In addition to a substantial amount of analysis during the initial planning period described above, the process to plan for and complete any new transmission and/or generation projects will also take about six years. Generally, these projects require time for siting/routing, design, land acquisition, permitting, procurement, and construction. Many constraints influence the timing of these projects and are not within the permittees' control.

According to the North American Electric Reliability Corporation ("NERC"), "[m]any states … have established requirements to maintain necessary amounts of generation resources to meet anticipated demand. In these jurisdictions, resource planning and generator retirement decisions must be approved by regulators or other governmental agencies."[172] In some cases, it can take years to obtain authorization from grid operators and PSCs to decommission units.

Maintaining mandatory grid reliability standards (e.g., NERC standards) after permittees start decommissioning units or while units are temporarily closed for repowering is a primary consideration. "To protect against threats to the power grid, [Regional Transmission Organizations ("RTOs")], which are responsible under federal law for ensuring the reliability of their respective power grids, generally require prior consultation or notification before retirements, outages, or extended periods of non-operation."[173] Time to coordinate and carefully plan these projects is essential "to ensure reliability in the region is not negatively impacted and to give the RTOs time to assess whether a unit must be kept in operation." USWAG Response, Ex. A, Vodopivec Decl. at A56. RTOs such as Midcontinent Independent System Operator ("MISO"), PJM Interconnection, LLC , and the Electric Reliability Council of Texas ("ERCOT"), among others, generally enter into agreements with permittees that are "designed to be short-term stop gaps while transmission upgrades sufficient to maintain the reliability of the grid are built. Typically, these … agreements, as short-term stop gaps, last for under two years; however, large-scale retirements may extend this period to reflect the larger number of required transmission upgrades." USWAG Response, Ex. A, Vodopivec Decl. at A56-A57.

To the extent permittees' retirement options include the closure of entire facilities, several considerations come into play. Closing a power plant requires "careful planning" that includes "evaluating replacement power options; either securing replacement power in the form of purchased power from the market or building a new … generating facility" and, importantly, assessing closure impacts on employees. Id., Ex. A, Morgan Decl. at A127–A128.

In addition, the need to coordinate facility outage schedules could also affect project timing. Most permittees schedule outages during periods of low electricity demand, such as the fall or spring, and do not typically schedule outages "for capital projects and plant maintenance work … during the summer." See id., Ex. A, Jenkins Decl., at A91. So essential tasks for these types of retirement or repowering projects "that would otherwise interfere with plant generation … must be timed to coincide with scheduled plant outages in order to avoid risks to critical plant reliability functions." Id; see also id., Ex. A, McManus Decl. at A108 ("Outages of individual generating units must be scheduled in advance and coordinated with the [RTO], and must be staggered in such a manner that generating capacity to satisfy electricity demand is continuously met."). These constraints limit the times of year when certain tasks can be accomplished.

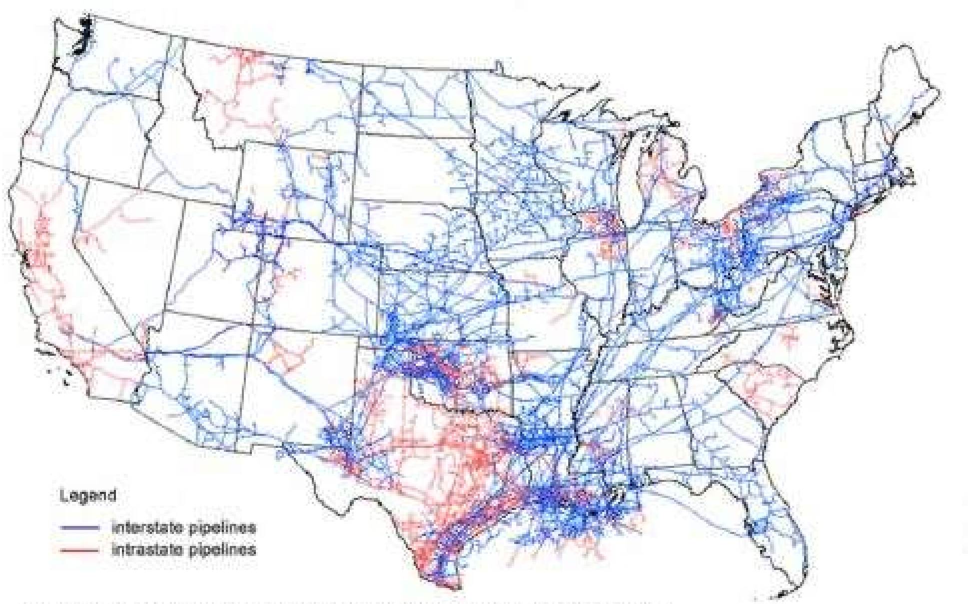
Moreover, "[s]afety considerations also drive project timing, in so far as there are limits upon . . . how quickly construction tasks can be performed and how many workers or pieces of equipment (e.g., earthmovers) can be deployed during a given construction task before there are threats to employee and contractor safety." Id., Ex. A, Jenkins Decl. at A92.

Furthermore, the infrastructure at many facilities across the country "was built decades ago…." Id. Therefore, "retrofitting existing, aged plant infrastructure … to accommodate updated pollution control and waste minimization processes is far more complicated and time consuming than constructing entirely new plant components within previously unused spaces. This is often because aged plant infrastructure must undergo significant modification prior to the installation of new components." Id. at A-92-A93.

Other constraints that permittees must consider for these types of projects, and that may affect timing, include: securing new rights-of-way; coordinating with other transmission line owners; procuring unique equipment and manpower; obtaining necessary permits to construct and operate; and defending against litigation that may arise at any step of the process.

In some cases, projects pose their own unique challenges. For example, some parts of the country are significantly underserved with natural gas pipelines and those types of projects are subject to their own permitting and construction delays and uncertainty.[174] As shown in the EIA map below, there is a lot of "white space" across the country, indicating a lack of access to pipeline infrastructure in many places.

Map of U.S. interstate and intrastate natural gas pipelines



Source: U.S. Energy Information Administration, *About U.S. Natural Gas Pipelines*

[175]

Overall, the entire process of planning and constructing new transmission and/or generation infrastructure could take at least six years because it is complex and involves many elements outside of permittees' control. See USWAG Response, Ex. A, McManus Decl. at A107 ("The steps generally described above are quite complex, as they involve fundamental changes to a plant's design and operation, and involve certain elements whose timing is beyond the control of [permittees]. For example, elements whose timing is out of the control of [permittees] are: the procurement of equipment, obtaining required permits, a limited construction season due to weather, and planned or unplanned outages of generating units."); Id., Ex. A, Hamrick Decl. at A138 ("These projects are complex, as they involve fundamental changes to plant design and operations and involve certain elements, which are not entirely within the control of [the permittee], including required permits from local, state, and federal authorities; equipment deliveries; and weather impacts on construction."). This six-year period is in addition to the two years permittees need to fully analyze the final rule and gather enough information to make a final decision on whether to retrofit, repower, or retire units.

[172]NERC, *Generation Retirement Scenario: Special Reliability Assessment,* 22, 25 (Dec. 18, 2018), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf (the "NERC Special Reliability Assessment").

[173] Response of Utility Solid Waste Activities Group and Luminant/Dynegy Companies in Support of Respondents' Motion for Voluntary Remand Without Vacatur and in Opposition to Petitioners' Motion for Partial Stay or, in the Alternative, For Partial Summary Vacatur ("USWAG Response"), Ex. A, Vodopivec Decl. at A56, *Waterkeeper Alliance, Inc. v. USEPA,* No. 18-1289 (D.C. Cir. Jan. 22, 2019), ECF No. 1769550.
[174] See, e.g., Laurence Hammack, *Another Delay, Cost Increase for Mountain Valley Pipeline,* THE ROANOKE TIMES (Oct. 22, 2019), https://www.roanoke.com/business/another-delay-cost-increasefor-mountain-valley-pipeline/article_1cf18404-9dd2-5e83-9fa5-7760e147ab8a.html (last visited Jan. 8, 2020) ("The projected cost of building the Mountain Valley Pipeline has gone up by another half a billion dollars. And the expected completion date, most recently slated for mid-2020, has been pushed back to the end of that year.... Mountain Valley attributed the latest delay and revised cost estimate … to 'various legal and regulatory challenges.'"); Robert Bryce, *Out of Gas: New York's Blocked Pipelines Will Hurt Northeast Consumers,* Manhattan Institute (June, 2019), https://www.manhattan-institute.org/natural-gasshortage-northeast (last visited Jan. 14, 2020).
[175] EIA, *Natural Gas Explained - Natural Gas Pipelines* (Dec. 5, 2019), https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php (last visited Jan. 20, 2020).

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 38

Comment Excerpt:

VI. SOUTHERN COMPANY SUPPORTS EPA'S SUBCATEGORY FOR RETIRING UNITS AND SUGGESTS CERTAIN MODIFICATIONS

Southern Company supports regulations that facilitate the continued delivery of clean, safe, reliable and affordable energy to customers. With certain modifications, EPA's proposal to establish a subcategory for units planning to retire by December 31, 2028 can reduce the risk of stranded investments and facilitate the orderly transition of an evolving generation fleet. During the same period in which Southern Company has been developing technologies to meet the 2015 limitations and moving toward coal ash pond closures, our industry has seen significant change. Due to a variety of factors, coal-based generation represents less of the Southern Company system's generation today than ever. The 2015 ELG rule requirements, particularly the limitations for flue gas desulfurization wastewater and bottom ash transport water, did not adequately address a reality where coal units are significantly diminished in their traditional role as baseload generation.

Southern Company generally supports EPA's proposal and offers additional evidence in support of an eight-year timeframe for retirement (i.e., 2028), particularly when replacement generation is required. Southern Company also offers specific suggestions to improve the proposed certification requirement supporting this subcategory. The timing of this certification should accommodate the timeline illustrated by these comments, and Southern Company suggests revisions to that effect.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 39

Comment Excerpt:

A. EPA Should Include a Subcategory for Units that will be Replaced or Repowered and Should Amend the Regulatory Text to Accommodate

The proposed rule solicits comments on "whether this subcategory should also be available for boilers that are planned to be repowered or replaced by 2028, not just those planned for retirement."[81] The capital investments required by the ELG rule are a significant factor that could result in more coal units becoming uneconomical in the near future. However, in certain cases, units cannot be retired without first identifying and procuring new capacity upon retirement and/or performing significant transmission system improvements. A likely prudent approach to ensuring reliability, utilities can construct new capacity resources to replace the required capacity shortfall, which may include transmission infrastructure improvements.[82] The final rule should facilitate this replacement process through a subcategory for retiring or repowering units.

To that end, EPA should broaden the proposed term "retired from service" to better accommodate repowering. As proposed, the term "retired from service" means "the owner or operator of a boiler no longer has, or is no longer required to have, the necessary permission through a permit, license, or other legally applicable form of permission to conduct electricity generation activities under Federal, state, or local law, irrespective of whether the owner and operator is subject to this part."[83] The "retired from service" phrase should be replaced with "cease coal-fired boiler operation" or similar language. A change to this effect ensures that repowering is permissible even though the repowered unit will continue to conduct electricity generation activities. This proposed change is also congruent with the provisions in the federal CCR rule for the "cessation of a coal-fired boiler[.]"[84]

81 Proposed Rule, 84 Fed. Reg. at 64,641.
82 Utilities can also replace generating capacity through purchase power agreements ("PPAs") with other generation sources, provided that doing so is both adequately and economically available when the need arises. However, a PPA may come at a cost premium relative to a new build and require lead time related to new transmission infrastructure.
83 Id. at 64,672 (to be codified at 40 C.F.R. § 423.11(w)) (emphasis added).
84 40 C.F.R. § 257.103(b)(1). For some instances of repowering, however, the boiler itself might not cease operations altogether; it might be retooled to burn a different fuel. Southern Company therefore recommends slightly different wording than that used by the CCR rule.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 40

Comment Excerpt:

B. Southern Company Supports an Eight-Year Timeframe for Retirement or Repowering.

The proposed subcategory requires facilities to retire by the end of 2028. Southern Company expects that EPA will promulgate a final version of this subcategory in late 2020. If that expectation holds, then the end of 2028 is an appropriate timeframe for unit retirement or repowering. This timeframe is comprised of several separate processes, each of which is explained below. Also included is a specific example supporting a timeframe of at least eight years for a utility to obtain regulatory approvals to retire coal units, if necessary, and/or complete the certification (if required) and construction of new generation.

1. The planning and evaluation process.

The Southern Company system's annual integrated resource planning process ensures customers receive reliable and affordable electric service by evaluating a diverse portfolio of demand-side and supply-side resources. This portfolio—comprised of demand response, energy efficiency, nuclear, natural gas, oil, coal, hydro, solar, wind, landfill gas, and biomass generation—maximizes value for customers in a wide variety of future economic and regulatory scenarios.

The Southern Company system considers retirement options for generating units as a part of the overall resource strategy. If environmental controls are mandated for a unit, then the economic value of the unit, including future operating costs, changes. The Southern Company system must then consider, through comprehensive economic and planning evaluations, whether it is in the best interest of customers to install the required control technology or to retire the unit and replace it with another resource.

2. The regulatory approval process.

It is imperative that this rule preserve flexibility to allow utilities to make investments in the best interest of its customers. Many regulated utilities cannot submit to the NPDES permitting authority a retirement certification prior to having first obtained such approval from their public service commission ("PSC"), which requires a full and thorough assessment as presented in a comprehensive integrated resource planning ("IRP") process. By way of example, this process for Georgia Power is detailed below.

At least every three years, Georgia Power is required by law to submit an IRP and seek approval from the Georgia PSC. Just as the annual system IRP does for Southern Company, the Georgia Power IRP details the Company's long-term plans for its energy resources to meet energy demand in a way that ensures continued delivery of clean, safe, reliable and affordable energy to its customers. To modify its generation portfolio, Georgia Power must follow the requirements established by law and adhere to the Georgia PSC's comprehensive rules. When adding replacement capacity resources, Georgia Power would likely be required to issue a request for proposals ("RFP"), evaluate RFP bids, and apply for certification of the new resource(s) with the Georgia PSC. Georgia Power complies with the laws, rules, and regulations that govern this process while also completing extensive analysis to ensure the final resource certifications are in the best interest of customers. The laws that govern this process are found in Title 46, Chapter 3A of the Georgia Code, and the IRP and RFP rules and regulations are those established by the PSC in Chapter 515-3-4 of the Rules and Regulations of the State of Georgia.

The Georgia PSC rules do not explicitly prescribe all facets of the process, but to receive approval of a certification request, the utility must ensure prudency of the RFP process, which necessitates a thorough and equitable evaluation. The timeline below lays out this process, incorporating Georgia law and the PSC rules and regulations.

Figure 6. Timeline illustrating Georgia Power process for regulatory approvals of a certification request.

As demonstrated in the timeline above, Georgia Power typically requires between 19 and 30 months before resources are certified or activities associated with building a new resource are initiated. Up to six months of additional time (not reflected in the timeline above) may be required prior to the certification filing depending on the level of activity at the Georgia PSC and whether certification requests will be included as part of an upcoming triennial IRP filing. While Alabama and Mississippi Power Companies are not required by their respective PSCs to file a formal IRP, each operating company undergoes a similar, although less prescriptive, resource planning process to ensure they also provide clean, safe, reliable, and affordable power to their customers. Regardless, each of Southern Company's regulated operating companies are required to seek approval from their respective PSCs to certify new resources. EPA should recognize that individual state regulatory processes differ and account for this by establishing a timeframe for retirement under this subcategory that is workable for all facilities in the industry.

3. The replacement generation construction process.

If a new generation resource is required and approved, the time required to complete new construction can vary based on technology. The Southern Company system currently estimates that planning, engineering, permitting, procuring, building, and testing a new natural gas combined cycle could require 62 months, while solar, storage, and other new technologies would likely be constructed in shorter durations.

4. Replacement generation example.

Taken together, the estimated time required for each of the sequences above supports a duration of approximately eight years from initial RFP to commercial operation. Table 3 describes a historical example illustrating the approval and construction of three new gas-fired units at Georgia Power's Plant McDonough. In this example, Georgia Power implemented its plan to meet future resource needs at Plant McDonough, near Atlanta, Georgia, which included the necessary replacement of its coal units with three natural gas combined cycle units to meet load demands in northeast Georgia as well as to comply with environmental regulations.

Table 3: Timeline of relevant regulatory approval and construction process associated with retirement and replacement generation.

Date*	Action
2004	After extensive study, including months of transmission system analyses** focusing on the north Georgia region, a course of action was presented for Georgia PSC approval, as required, in the 2004 Georgia Power Company IRP filing. The course of action included soliciting new-build generation to locate in the north Georgia region to address critical transmission system needs. Georgia Power is required to file the IRP at least every 3 years, and the proceedings last up to 6 months, which includes discovery and hearings under oath.
June 6, 2006	After review and approval by the Georgia PSC, GPC issued a formal RFP, as ordered by Georgia PSC rules, seeking generation capacity to meet load growth needs while encouraging new generation siting targeting the north Georgia region.
January 31, 2007***	Upon completion of the solicitation, as required by the Georgia PSC, GPC filed an application for certification of constructing three new combined cycle units and for decertification of the two operating coal units at Plant McDonough and reuse of the adjacent, previously retired Plant Atkinson property.
September 14, 2007	Following the certification proceeding, the Georgia PSC approves the application to construct three combined cycle units at the Plant McDonough-Atkinson site and to retire the two operating coal units there.
September 30, 2011	Unit 1 retired.
December 2011	The first combined cycle unit (Unit 4) achieves commercial operation.
February 29, 2012	Coal Unit 2 is retired, making way to complete construction of the two remaining combined cycle units.
April 26, 2012	Unit 5 online.
October 28, 2012	The third and final combined cycle unit (Unit 6) is completed.

*Date reflects actual dates of activities, not proposed.

**Transmission constraints are an important and critical consideration when addressing changes to the generation fleet, such as new generation or retiring generation. Significant transmission system upgrades may be needed to support reliable operations and resiliency of the system, depending on the location of the generation. These updates may require long lead-time planning, land acquisition, design, and construction efforts in order to support the new generation or accommodate future retirements.

*** Georgia Power filed for operation dates of the new combined cycle units for 2011 and 2012; however, due to lower-than-forecasted load growth, GPC delayed operation of these facilities and the associated coal unit retirements, acting in the best interests of customers.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 41

Comment Excerpt:

C. EPA Should Clarify the Certification Deadline to Account for the Time Required to Approve and/or Complete Retirement.

The information above establishes the need to allow through at least 2028 to complete unit retirement. It also establishes that utilities might reasonably need time through at least the end of 2023 to submit a certification of retirement. Using the example of the Georgia PSC process above, an owner could need up to 30 months to secure approval of retirement. A final rule promulgated at the end of 2020 would therefore require the ability to certify out to mid-2023 at least, and an additional six months might be necessary depending on the level of activity at the PSC and whether certification requests will be included as part of an upcoming triennial IRP filing. A six-month buffer also helps account for variation in state PSC processes, delay in promulgation of the final rule, additional time to account for the fact that companies will likely be considering this regulatory option for a number of facilities at the same time, or uncertainty over the desirability of retirement caused by post-promulgation challenges.

The proposed rule does not appear to provide sufficient time for that certification in many instances. To qualify for the subcategory, the initial certification statement must be submitted either "with the permit application, or where a permit has already been issued, by the as soon as possible date[.]"[85] Southern Company recommends two changes to this language to ensure that utilities have a reasonable opportunity to obtain the regulatory approvals necessary for retirement and certification of new resources. Without sufficient time, this subcategory might prove unavailable in practice.

First, EPA should remove the phrase "with the permit application." Permits must be renewed every five years with a new application due at least 180 days before expiration of the prior permit.[86] Because permittees obtained permits at different times, they have different deadlines for submitting renewal applications. Some of these applications might be due well before the end of 2023, or even soon after the final rule becomes effective; consequently, the permittee would have no meaningful opportunity to secure PSC approval for new retirements. They should not be denied that opportunity based on the happenstance of permit renewal timing.

Second, EPA must resolve an ambiguity in the alternative deadline—"the as soon as possible date" or applicability date—in a manner that recognizes the realities of varying PSC processes. If EPA proceeds with the rule as proposed, many permits will include at least two applicability dates: one for BATW that extends no later than the end of 2023 and one for FGD wastewater that extends no later than the end of 2025. It is not clear to which date the proposed rule refers, and this ambiguity will undoubtedly invite permit challenges and legal disputes.

The final rule should clarify that the retirement certification is due by the latest applicability date in the permit. This clarification better ensures that utilities have the time needed to complete the PSC process. As explained above, that process might extend through at least the end of 2023, but some BATW applicability dates might arrive earlier and therefore create significant risk of precluding retirement certification. That leaves the second, later applicability date (likely that for

FGD wastewater) as the only feasible option for accommodating state regulatory approval. This later date should therefore set the time required for certification.[87]

Of course, an owner who is either able to obtain retirement approval before that date or is not required to seek retirement approval will have more flexibility in its construction schedule. Along with the possibility of some stranded investments, this is an incentive to seek approval and certification without unreasonable delay. Southern Company expects that many utilities will obtain and submit retirement certification in advance of the latest applicability date, but that date provides better assurances against unpredictable events that impact the IRP process and PSC approval(s). It also recognizes that other options for replacement generation might require more time to evaluate and plan, even if they require less time to implement.[88]

85 Proposed Rule, 84 Fed. Reg. at 64,677 (to be codified at 40 C.F.R. § 423.19(f)(1)).
86 40 C.F.R. §§ 122.21(d)(2), 122.46(a).
87 The latest applicability date is also more consistent with planning under the Clean Air Act. The Affordable Clean Energy rule requires state implementation plans to be filed with EPA in mid-2022 with implementation in mid-2024. These implementation plans will incorporate resource planning considerations similar to those for ELGs (i.e., considering end of useful life).
88 See supra note 82. In some instances, the additional flexibility for retirement planning might result in a more favorable outcome in pollutant loadings compared to the construction of replacement generation.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 4

Comment Excerpt:

Vistra supports EPA's proposal to establish new subcategories, which would have separate effluent limitations, because the imposition of costly new technologies on boilers that intend to retire in the near-term and units that are operating as non-baseload units would be disproportionately costly and could result in significant reliability impacts.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 8

Comment Excerpt:

EPA appropriately recognizes that "cost, the age of the equipment and facilities involved, non-water quality environmental impacts (including energy requirements), and other factors" necessitate the subcategorization of boilers retiring by 2028.[7] Coal-fueled facilities are facing increasing regulatory and economic pressures. Therefore, many companies are developing plans to retire older units that are no longer economically competitive. In fact, the U.S. Energy

Information Administration ("EIA") projects that "almost 90 [gigawatts ("GW")] of coal-fired capacity will retire between 2019 and 2030."[8] However, if no subcategory is established, it could leave these facilities with a Hobson's choice: install costly new technologies that could result in significant stranded assets in the short-term or choose to retire these units prematurely which may cause reliability concerns.

As EPA explains in the Proposed Rule, its examination of costs revealed that if a facility retires in less than 20 years (the amortization period EPA assumes for its cost analysis), the facility could be subject to "capital costs per MWh 10 to 15 times higher than . . . with the assumed 20-year amortization in the EPA's cost estimates, and the costs per MWh remain more than double the EPA's estimates until amortization of six to eight years, depending on the discount rate."[9] Further, a recent reliability assessment developed by the North American Electric Reliability Corporation's ("NERC") "found that if these retirements happen faster than the system can respond (e.g., construction of new base load), significant reliability problems could occur."[10] Accordingly, EPA has correctly determined that the technologies identified as BAT for other units are not appropriate for boilers retiring by 2028 "due to the unacceptable disproportionate costs they would impose; the potential of such costs to accelerate retirements of boilers at this age of their useful life; [and] the resulting increase in the risk of electricity reliability problems due to those accelerated retirements . . . ."[11]

Importantly, EPA's use of 2028 as the retirement year for the proposed subcategory is appropriate to harmonize the ELG rule with the Coal Combustion Residuals ("CCR") rule and allow companies to make fully informed business planning and capital allocation decisions.[12] As EPA explains in the Proposed Rule and previously explained in the 2015 ELG rule, "the ELGs and CCR rules may affect the same boiler or activity at a facility. . . . [Therefore,] when the EPA finalized both rules in 2015, the Agency coordinated them to facilitate and minimize the complexity of implementing engineering, financial, and permitting activities."[13] This "continues to be a consideration in the development" of the Proposed Rule.[14] EPA's use of October 17, 2028, as the deadline for closure of certain CCR units at retiring facilities is fully justified.[15] Therefore, it is appropriate for EPA to rely on a 2028 timeline for the ELG rule to ensure "the ELG will not restrict the use of [the CCR rule's] alternative closure provision . . . ."[16]

[7] 84 Fed. Reg. at 64,640.
[8] EIA, U.S. Coal Plant Retirements Linked to Plants with Higher Operating Costs (Dec. 3, 2019), https://www.eia.gov/todayinenergy/detail.php?id=42155.
[9] 84 Fed. Reg. at 64,640 (emphasis added).
[10] Id.
[11] Id.
[12] Vistra is filing these comments in the docket for EPA's proposed revisions to the ELG rule in addition to the docket for EPA's proposed revisions to the CCR rule in accordance with EPA's request. Id. at 64,626.
[13] Id.
[14] Id.
[15] 40 C.F.R. § 257.103(b)(3).
[16] 84 Fed Reg. at 64,641.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.

Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 12

Comment Excerpt:

A. EPA Fails To Account For Pollution Loads From 'Early Retirement' Units

According to EPA's Proposed TDD, the Agency "removed coal-fired generating units that will retire or convert fuel type prior to December 31, 2028 from the analyses supporting this proposed rule."[61] This means that EPA did not calculate – and the public cannot calculate – the pollution reductions (and associated costs) that might be achieved by requiring pollution control upgrades at these plants. EPA suggests that costs might be disproportionately high for 'early retirement' units because they have fewer years of operating life over which to amortize costs, and might end up with stranded assets.[62] This is simply not a credible concern in light of the fact that these plants can lease, rather than purchase, treatment systems.[63] EPA must evaluate the costs and pollution reductions associated with eliminating the discharge of pollution from <u>all</u> units, including those scheduled to retire by 2028. EPA's failure to evaluate such costs and benefits renders its analysis for the 2019 Proposal arbitrary and capricious.

[61] Proposed TDD at 3-4.
[62] 84 Fed. Reg. at 64,640.
[63] See, e.g., ERG, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367, at M-2, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019).

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 2

Comment Excerpt:

The Retirement Subcategory Should Include Units Repowered by December 31, 2028.

EPA proposes to establish a subcategory for coal-fired units that have a limited remaining useful life or, in other words, those that certify they will retire by December 31, 2028. For this proposed subcategory (the "Retirement Subcategory"), EPA proposes surface impoundments as the technology basis for BAT, and it proposes to establish BAT limitations on TSS for both FGD wastewater and BATW that are equivalent to existing TSS limits. Proposed § 423.13(g)(2)(i); § 423.13(k)(2)(ii). Coal-fired units qualifying for the exemption would not have to meet the other new BAT limits for FGD wastewater and Bottom Ash Transport Water (BATW). Talen generally supports the proposed Retirement Subcategory, with a few exceptions and recommendations outlined below including most-importantly the expansion to include repowered units.

EPA solicits comment on whether the Retirement Subcategory should include units that are planned to be *replaced* or *repowered* with non-coal fuel sources[1] by 2028 and, if so, whether BAT should be the same as for retiring units. 84 Fed. Reg. at 64,641.[2] Talen strongly agrees the Retirement Subcategory should include repowered units, such as will be the case by 2028 for Talen's Brunner Island facility in York Haven, PA. Talen added natural gas capability to our 3 coal fired boilers and has plans to fire only natural gas in these boilers (considered to be repowered) by the end of 2028. Those repowered units should be subject to the same BAT basis as retired units, for the reasons given below:[3]

1 The terms "repower" and "fuel conversion" are used interchangeably. They both refer to converting a unit's fuel source from coal to non-coal sources.
2 It is unclear what EPA means by "replaced," as a separate category from "retired" units. Many units slated for retirement will be replaced by non-coal units that will not be subject to the Rule.
3 While Talen argues that units certified to be repowered by the end of 2028 should be included in the Retirement Subcategory, coal-fired units are the focus of this rulemaking and this Subcategory. So, for those units included in this Subcategory, permitting authorities should only need to consider whether the coal-fired unit(s) cease operating by the end of 2028 to ensure compliance with certifications.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 4

Comment Excerpt:

1. Repowering Eliminates All Pollutants Related to Coal-Firing, Just as Unit Retirement Does.

The Agency "removed coal-fired generating units that will retire or convert fuel type prior to December 31, 2028, from the analyses supporting this Proposed Rule because they will cease discharging FGD wastewater or bottom ash transport water prior to the date of compliance…." Supplemental TDD at 3-4. Whether a permittee decommissions a coal-fired unit or repowers it, the result will be the complete elimination of BATW and FGD wastewater discharges, which are the subject of this rulemaking. *See* Supplemental TDD at 6-3, n. 39 ("The EPA determined that baseline and post-compliance *pollutant loadings are equal to zero for … units that announced plans to retire, convert to a non-coal fuel source*, or change/upgrade ash handling practices by the time the … units are required to meet the requirements of the proposed rule.") (emphasis added). Therefore, the environmental benefits related to BATW and FGD wastewater and, the ELG parameters being reconsidered, for repowering a unit are identical to those of retiring a unit. There is no environmental basis for distinguishing between retiring units and those being repowered.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy

Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 5

Comment Excerpt:

2. Excluding Repowered Units from the Retirement Subcategory Would Waste Money and Resources.

EPA solicits comments on whether units that have been or will be repowered are unable to finance both the repowering retrofit and FGD wastewater and BATW technology upgrades that would be applicable to the unit prior to completion of the repowering. 84 Fed. Reg. at 64,641.

A permittee who is already planning to repower or has repowered a unit or an entire facility could be required to spend tens of millions of dollars to retrofit units with BATW- and FGD wastewater-compliant technology only to operate them for a few years. Moreover, the Agency examined cost implications of complying with the proposed rule under hypothetical unit retirements, but it did not conduct the same analysis for units that would need to install new technology only to repower a few years later. *See* 84 Fed. Reg. at 64,640; *see generally*, Supplemental TDD at § 5. Even if a repowered unit could afford to pay off financing related to the abandoned equipment, however, it is an imprudent use of resources, and, in many cases, ratepayers would absorb these additional costs for equipment that will be mothballed a few years after it is put into service.

Specifically, at Talen's three units at its Brunner Island facility, which since 2017 can operate on both natural gas and coal, it reached an agreement with the Sierra Club in 2018 to phase out the coal operations by the end of 2028. This phase out includes an interim reduction in coal firing starting in 2023 where the plant will not operate on coal during the ozone season (May through September). Requiring significant investment at this plant, which will see two phases of reductions in coal fired operations, is not prudent.

Furthermore, Talen's investment in the continued operation of this plant has an overall benefit to the local economy, being forced to spend excessively for a short-lived issue could adversely impact the continued operation of this plant.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 7

Comment Excerpt:

3. Including Repowered Units in the Retirement Subcategory Is Consistent with the CCR Rule.

One of EPA's reasons for proposing the Retirement Subcategory is to "ensure that facilities could make better use of the CCR rule's alternative closure provision, by which an unlined surface impoundment could continue to receive waste and complete closure by 2028." 84 Fed. Reg. at 64,641. The Agency notes that "facilities may have to cease receiving waste well in advance of that date" but "a 2028 date ensures that the ELG will not restrict the use of this alternative closure provision regardless of when a facility ultimately ceases receipt of waste." 84 Fed. Reg. at 64,641.

The CCR rule's alternative closure provisions allow units otherwise required to close to continue receiving CCR under certain circumstances. For a CCR surface impoundment that is 40 acres or less, if the permittee agrees to cease operation of the coal-fired boiler, the impoundment is permitted to continue receiving CCR, but must complete closure by October 17, 2023. 40 C.F.R. § 257.103(b)(2). If the surface impoundment is larger than 40 acres and the permittee agrees to cease operation of the boiler, the impoundment may continue receiving CCR, but it must complete closure by October 17, 2028. 40 C.F.R. § 257.103(b)(3).

Talen commends EPA's effort to harmonize the ELG and CCR rules in order to not foreclose use of the CCR alternative closure provisions. The Retirement Subcategory is a critical feature of the Proposed Rule, and the eight-year deadline provides the necessary time for the industry to transition the nationwide fleet in light of the ELG and CCR rules.

The CCR rule, however, is no reason to exclude repowered units from the Retirement Subcategory. Nothing in the CCR rule prevents permittees from using the alternative closure provisions for boilers that are being repowered with a non-coal fuel source. In fact, repowering is entirely consistent with the intent of the CCR rule alternative closure provisions that is allowed when permittees cease using *coal-fired* boilers. *See* 80 Fed. Reg. 21,301, 21,341 (Apr. 17, 2015) ("These requirements also do not apply to fly ash, bottom ash, boiler slag, and flue gas desulfurization materials, generated primarily from the combustion of fuels (including other fossil fuels) *other than coal*…. Fuel mixtures that *contain less than 50% coal* are not considered to be CCR, but other fossil fuel wastes…. Similarly, EPA determined that *regulating natural gas combustion wastes is not warranted* because the burning of natural gas produces virtually no solid waste."); 40 C.F.R. § 257.103(b)(3) ("…the *coal-fired* boiler must cease operation, and the CCR surface impoundment must complete closure…"). By definition, if a unit is repowered using only natural gas, it is no longer a coal-fired unit, the former coal-fired unit has ceased operation, and the repowered unit does not produce CCR.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 10

Comment Excerpt:

6. Excluding Repowered Units from the Retirement Subcategory Would Discourage Repowering at Existing Coal-Fired Facilities.

Permittees often make repowering decisions in conjunction with retirement decisions, and EPA's updated industry profile illustrates this fact. *See* ERG, *Review of Company Rational for Retirements, Deactivations, and Fuel Conversions,* EPA-HQ-OW-2009-0819-7374 (Feb. 27, 2019). EPA's industry profile from February 2019 identifies approximately eight plants that have or will repower (*i.e.*, refuel) in conjunction with retirement or deactivation of coal units. ERG, EPA-HQ-OW-2009-0819-7374. This demonstrates that repowering is a common strategy for reducing reliance on coal-fired generation.

In addition, EPA's updated industry profile from July 2019 demonstrates repowering is increasingly common at former coal-fired facilities. The Agency identified 27 plants that, as of October 2018, had converted or planned to convert coal-fired units to a different fuel source. ERG, *Memorandum re: Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule*, EPA-HQ-OW-2009-0819-7373, ("ERG 2019 Industry Change Memo"), Table A-3, 18-19 (July 31, 2019).

Repowering units on the same site as a former coal-fired unit is a common practice because existing infrastructure and permits can continue to be used and the property is already an established industrial site. According to the EIA, there are four main phases of a coal-fired unit decommissioning—retirement, decommissioning, remediation, and redevelopment. Redevelopment "may involve repurposing the site for another generation technology or some other commercial, industrial, or municipal application. Coal-fired power plants typically occupy land in or near downtown areas or along rivers, and they usually have access to railways, roadways, water, sewers, and other infrastructure." EIA, *More U.S. Coal-Fired Power Plants Are Decommissioning as Retirements Continue* (July 26, 2019), *available at* https://www.eia.gov/todayinenergy/detail.php?id=40212 (last visited Dec. 16, 2019). Repowering an entire power plant with natural gas, for example, is "a viable option for power providers because much of the critical infrastructure is already in place, including transmission lines, substations, and water." EIA, *More U.S. Coal-Fired Power Plants Are Decommissioning as Retirements Continue*; *see also* Don Hopey, *New Castle power plant switching to natural gas*, PITTSBURGH POST-GAZETTE (June 24, 2013) *available at* https://www.postgazette.com/local/region/2013/06/24/New-Castle-power-plant-switching-to-naturalgas/stories/201306240188 (last visited Dec. 23, 2019) (for units repowered using the existing boilers, all existing infrastructure is reused). Also, repowering at the same facility ensures that the site is already approved and permitted for generation activities and discourages unwarranted development of "greenfield" sites for new generation.

By excluding repowered units from the Retirement Subcategory, EPA would discourage permittees from repowering units to compensate for retiring units. It also would discourage permittees from using ideal sites (former coal-fired units/facilities) for their repowering projects. Talen urges EPA to take the opposite approach by including repowered units in the Retirement Subcategory to encourage reuse of existing power generation facilities, which is both economically efficient and environmentally appropriate.

Talen is considering the option of repowering its Montour plant located near Washingtonville, PA given its success in repowering its Brunner Island plant discussed above. Montour is working on the various approvals and permits as it considers this investment but has yet to make its final decision because of market and regulatory uncertainties. https://www.dailyitem.com/news/local_news/talen-delays-montour-plant-gas-conversion/article_3153990b-e573-5238-b176-32b95c6a94f6.html. However, the decision to proceed with such a significant investment to secure the long-term future of its Montour plant will likely be adversely affected, if it would also be subject to tens of millions of dollars that would be required to comply with the BATW and FGD wastewater requirements in the ELG when it would only be operating as a coal fired plant for a few short years.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 12

Comment Excerpt:

EPA Should Amend the Definition of "Retired From Service."

EPA proposes to define "retired from service" as meaning "the owner or operator of a boiler no longer has, or is no longer required to have, the necessary permission through a permit, license, or other legally applicable form of permission to conduct electricity generation activities under Federal, state, or local law, irrespective of whether the owner and operator is subject to this part." Proposed § 423.11(w). Talen urges the Agency to amend this definition for several reasons.

As already mentioned above, the Retirement Subcategory should include units that will be repowered by December 31, 2028. Talen urges EPA to broaden the definition to include repowered units in the definition of the Retirement Subcategory. If a permittee certifies that it will repower *or* retire a unit by December 31, 2028, then the unit should be allowed to operate until the certified date without meeting any new BAT limits for BATW or FGD wastewater beyond the prescribed TSS limits. Furthermore, this will not affect the permit authority from requiring treatment to meet any discharge specific water quality-based limits.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 13

Comment Excerpt:

Also, the proposed requirement for surrender or withdrawal of the licenses/permits necessary to generate electricity is unworkable. It clearly will not work where the unit is being repowered, and many permittees already have both coal-fired and non-coal-fired units at the same generating facilities and thus need to retain their licenses to generate electricity for the noncoal-fired units. Furthermore, permitting authorities decide whether and when to amend licenses to remove the authority to generate for units being retired. In other words, this decision is not entirely within the permittee's control. The permittee cannot be assured that the license withdrawal requirement EPA proposes in the definition of "retired from service" can be timely fulfilled, despite the permittee's best efforts to accomplish this step. A backlog of applications for license modifications, for instance, could jeopardize a permittee's compliance with its retirement certification.

For this reason, the certification statement should be self-implementing (i.e., effective upon the submittal of the certification by the permittee) and not dependent on any actions by third parties. Talen agrees with UWAG's recommendation (a certified letter signed by responsible corporate official) would be within the permittee's control and legally binding. Nothing further should be required.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 83

Comment Excerpt:

B. EPA's Proposed Subcategory for Boilers Retiring by 2028 Is Not Legally Permissible and Not Supported by Evidence.

EPA proposes to establish a subcategory for boilers that commit to retire by December 31, 2028.[295] Units falling into this subcategory would be subject to effluent limitations for both FGD wastewater and bottom ash transport water based on surface impoundments as the best available technology.[296] EPA asserts that this subcategory will prevent "premature closures" of units that might occur where units already scheduled to retire by 2028 would face pressure to retire earlier (e.g., by 2023) in order to avoid installing pollution control systems. According to EPA, these "premature" retirements could adversely affect reliability.

This proposed subcategory for boilers retiring by 2028 is supported by neither the law nor the evidence in the record. According to Commenters' analysis of EPA's data, 66 units discharging bottom ash transport water, FGD wastewater, or both would be exempt from meaningful pollution limits as a result of this subcategory.[297] These units would be allowed to discharge highly toxic wastewater for up to eight years longer than otherwise allowed. This subcategory amounts to a massive loophole in the BAT standards that fails to protect downstream communities or ensure an even playing field across the steam electric generating industry. As discussed in Section X.C – Retirement Subcategory Enforceability, the subcategory is also unenforceable and therefore prone to gaming by facilities seeking to skirt reasonable clean water protections.

[295] Id. at 64,640.
[296] Id.
[297] Attachment: Units in 2028 Subcategory (attached).

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 84

Comment Excerpt:

1. The Clean Water Act Does Not Permit EPA to Establish a Subcategory Solely to Prevent Facility Closure

EPA asserts that in establishing this subcategory, it considered the statutory factors of "cost, the age of the equipment and facilities involved, non-water quality environmental impacts (including energy requirements), and other factors as the Administrator deems appropriate."[298] Yet EPA gives mere lip service to the breadth of these statutory factors. EPA's sole reason for establishing this subcategory is cost, and the possible impact of those costs on continued facility operation. EPA asserts that units with plans to retire by 2028 face disproportionately high costs of compliance due to the shorter period of time in which those units could recover the capital costs of measures to meet the ELGs for FGD and bottom ash wastewater. This could lead to "premature closure" of those units, prior to the ELG compliance date, in order to avoid incurring those costs.

To begin with, EPA's assertion that the closure of certain units before their currently scheduled retirement date is "premature" conveys an inappropriate and misinformed judgment about when such units *should* retire. Generation units should retire when, after factoring in the costs of compliance with environmental regulations mandated by statute, they are uneconomical to operate compared to other available sources of generation. There is nothing "premature" about the retirements in question—prior to the 2015 ELG Rule, EPA delayed updates to the ELGs for decades, and plants that cannot afford to invest in modern and affordable pollution control technologies are retiring at the time that they should, or perhaps even later than appropriate. Moreover, the average age of the units in this subcategory is over 54 years, which is close to the maximum lifetime of coal units; retirement of these units is in no way premature.

Avoiding premature closure of units is not a valid basis for establishing a subcategory. As explained in Section II – Legal Background, "Congress clearly contemplated that cleaning up the nation's waters might necessitate the closing of some marginal plants."[299] Indeed, it would contravene the Clean Water Act's purpose to subcategorize plants solely to prevent those plants from closing due to increased costs. Doing so amounts to creating a special exemption for the worst-performing plants, rather than requiring such plants to instead meet the standard set by the best-performing plant in the industry. The Clean Water Act recognizes that some units may need to retire as a result of technology-based standards; this is an acknowledged and accepted impact of BAT standards which are intended to reflect "a commitment of the maximum resources economically possible to the ultimate goal of eliminating all pollutant discharges."[300] To set weaker BAT standards in order to avoid the closure of marginal plants undermines the statute's purpose.

Indeed, in the 2015 ELG Rule, EPA rejected requests that it establish a subcategory based on retirement dates.[301] EPA justified its rejection of these proposed subcategories on grounds that the final rule was "economically achievable for the industry as a whole" regardless of plants' expected retirement dates.[302]

EPA did consider whether it would be appropriate to establish differentiated requirements for units or plants based on their remaining useful life, but concluded that even plants and units that are retiring or expected to retire are still capable of achieving the limitations and standards in the final rule. EPA's economic achievability analysis considered potential plant closures attributable to the final rule. As EPA's analysis makes clear, the final rule is affordable to the industry as a whole . . . .[303]

EPA's decision in 2015 was correct—subcategories should not be created solely for the purpose of ensuring that the rule is economically achievable for each idiosyncratic subset of units that EPA can conjure. The proper unit of analysis for the statutory factor of economically achievable is the "industry as a whole." EPA's reasons for departing from its 2015 rejection of a similar requested subcategory are unpersuasive and inconsistent with the fundamental purpose of the Clean Water Act.

It is well-established that cost "is not a paramount consideration" in determining pollution control requirements.[304] Even if EPA had studied the cost of compliance for these units, which, as described below, it did not, it is inappropriate for EPA to create a subcategory based solely on the higher costs that soon-to-retire units may face compared to their peers. While EPA may consider cost in delineating subcategories or making a BAT determination, balancing of costs against benefits is not permitted,[305] It is especially inappropriate to give such weight to cost where the costs do not reflect differences in the plant's product type, process type, raw material or wastewater characteristics, which are the most common bases on which EPA has previously established subcategories. EPA rejected a request for a similar subcategory in 2015 because its record "shows that neither age nor location of a plant or generating unit 'by itself in general affect the wastewater characteristics, the processes in place, or the ability to install and operate the treatment technologies evaluated as part of this rulemaking.'"[306]

Instead, the consideration of costs here reflects the plant's supposed ability to *recover* the costs. Ability to recover costs varies widely within the steam electric generating unit sector, based on differences in regulatory structures, energy prices in the different wholesale markets in which particular units may sell, and myriad other factors. EPA's proposal to subcategorize on this basis would open the Agency up to countless requests for subcategories based on differences in the profitability of various plants. Subcategorizing on the basis of ability to recover costs requires EPA to go far outside its core expertise, creates ample opportunities for gaming, and is contrary to the purpose of federal ELGs to establish some degree of uniformity in regulatory requirements across the industry. EPA offers no limiting principle for why certain plants' challenges with recovering costs justify a subcategory and not others. Nor does EPA articulate why it has drawn the line at 2028. The same rationale could be offered for extending this exemption to resources retiring through 2030 or 2035 – indeed, EPA seeks comment on whether it should extend the subcategory in this manner. This why consideration of the recovery of revenues – a complex economic matter that EPA cannot accurately model – is an inherently flawed basis on which to create a subcategory. The exception could easily swallow the rule, thus undermining the fundamental objective of the Clean Water Act to promote the rapid elimination of pollution from our nation's waters.

EPA has failed to fully consider the other statutory factors, besides cost, in proposing to establish this subcategory. EPA does not discuss the age of the units falling into this subcategory, and previously found that bottom ash conversions "have occurred on generating units that have been operating for over 50 years." [307] EPA does not evaluate whether the processes involved at units that would retire by 2028 differ in any relevant way from those not retiring. Nor does EPA evaluate all of the non-water quality environmental impacts of establishing this subcategory. In part this is because EPA failed to include these units in its baseline case for IPM modeling, which would have disclosed the air quality and climate impacts of continued operation of these units. EPA's failure to consider the broader suite of factors required by statute reflects an elevation of one factor in a manner that undermines the overall statutory standard that BAT be technology-forcing and reflects the maximum commitment of resources to the goal of eliminating pollution from the nation's waters.

[298] 84 Fed. Reg. at 64,640.
[299] *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1051-52 (3d Cir. 1975).
[300] *Sw. Elec. Power Co. v. EPA*, 920 F.3d 999, 1030 (5th Cir. 2019) (quoting *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980)).
[301] EPA, Response to Comments on ELG for Steam Electric Power Generating Point Source Category, at 3-579, 3-588, Docket ID No. EPA-HQ-OW-2009-0819-6469 (Sept. 2015).
[302] Id. at 3-548.
[303] Id. at 3-579.
[304] *BASF Wyandotte Corp. v. Costle*, 598 F.2d 637, 656 (1st Cir. 1979); see also *Am. Iron & Steel Inst.*, 526 F.2d at 1051 ("[I]t is clear that . . . the cost of compliance was not a factor to be given primary importance."); *Weyerhaeuser Co.*, 590 F.2d 1011, 1025 (D.C. Cir. 1978) (explaining that Congress's commitment to cleaning up the nation's waters was illustrated "by the drafters' realization that enforcement of the Act would probably shut down some plants around the nation"); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 250 ("Because standards based on BAT, like BAT itself, reflect the intention of Congress to push industries toward the goal of eliminating the discharge of pollutants as quickly as possible, this goal is factored into determinations of the reasonableness of the costs associated with the regulation.").
[305] *Sw. Elec. Power Co. v. EPA*, 920 F.3d at 1007.
[306] EPA, Response to Comments on ELG for Steam Electric Power Generating Point Source Category, at 3-590, Docket ID No. EPA-HQ-OW-2009-0819-6469 (Sept. 2015).
[307] Id. at 3-591 (citing DCN SE05813), Docket ID No. EPA-HQ-OW-2009-0819-6206 (Nov. 3, 2015).

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2. *EPA has not established that units in this subcategory face unacceptable costs or will retire prematurely as a result*

a. EPA did not examine the costs of compliance for units retiring by 2028

While EPA rests its entire case for this subcategory on cost, it never evaluates the costs of compliance for the units it indicates would fall into this subcategory. As detailed in the report of Synapse Energy Economics,[308] EPA excluded these units from its baseline scenario for purposes of IPM modeling. EPA did not develop cost estimates for these units, or even survey the relevant water pollution control technologies in place at these units.

Lacking this critical data, EPA's sole argument that cost distinguishes the units in this subcategory is based on a generalized arithmetic exercise in which a theoretical $100 million capital cost for compliance is amortized over different numbers of years.[309] While this unsurprisingly illustrates that the annualized cost is higher when costs much be recovered over fewer years, it says nothing about the scale of the capital costs that would actually be incurred at these units. According to EPA's IPM inputs for the baseline scenario, unit-level capital costs average $11.9 million. Even a multiple unit plant would likely incur costs far less than the $100 million that EPA uses for illustrative purposes. As such, the annualized cost values presented in Table 2 of the August 2019 ERG memo are highly misleading. EPA's IPM inputs for the baseline scenario do contain cost estimates for some units that will retire by 2028, where those retirements were announced after EPA's compiled data for its IPM runs. For example, the two units at Entergy Arkansas' White Bluff plant would incur capital costs of just over $51,000 to comply with the requirements under the 2015 rule.[310] Even amortized over the eight years that these two units will presumably remain in operation, rather than the 20-year life otherwise expected, the annualized cost is a drop in the bucket for these two 850 MW units. This example reveals that units retiring by 2028 will not necessarily incur disproportionate or unachievable economic costs; retirement date is simply not a valid proxy for cost, or a reliable indicator of costs that might drive even earlier retirement.

EPA has not provided information about what pollution controls are already installed at the units in this subcategory, and what additional costs would be incurred. For example, one of the plants in this subcategory, according to EPA data, is the Allen Steam Station in North Carolina, all five units of which will retire by 2028. The Allen plant already has a chemical precipitation and biological treatment system for its FGD wastewater—the technology combination that EPA determined to be BAT in the 2015 rule. As such, the Allen plant would likely not incur material costs to comply with EPA's current proposed limits for FGD wastewater, which are based on a less sophisticated treatment technology. Yet, by falling into this subcategory, Allen may no longer be required to operate its already-installed treatment system (except as required to meet the water quality based effluent limits in its permit). Three units at the Pacificorp Dave Johnston plant would also fall into the retirement subcategory because they are scheduled to close in 2027 according to EPA data. Yet from 2017 to 2019, the operator spent nearly $15 million to convert the bottom ash systems for those three units to comply with the ELGs.[311] Thus, these units may already be close to compliance with the 2015 ELG Rule bottom ash transport water requirements.

Among the many reasons that EPA in 2015 rejected an exemption for plants that would retire soon was that the cost of meeting the standards might be relatively small and quick to implement at a particular plant, and that permitting authorities could readily determine this on a case-by-case basis. EPA gave several examples, such as a plant with a FGD wastewater stream that has the equipment in place for various forms of chemical precipitation, but is currently not adding the chemicals needed to achieve the pollutant reductions. EPA noted: "[i]t would not be appropriate to suggest that such a plant should not have to meet the effluent limitations for the several remaining years of operation, particularly given the very little (if any) additional capital cost and relatively little added O&M costs."[312] A second example EPA offered was "a plant that typically operates a dry fly ash handling system but occasionally operates a backup wet system during startup or when the dry system is undergoing maintenance or ash is not being marketed." EPA explained that "such a plant clearly has the capability to meet the zero discharge limitation." "Because such plant-specific considerations need to be taken into account, and because there are situations where it would be reasonable to require a plant to meet the BAT effluent limitations even if only for a relatively short period before it retires, EPA determined it was not appropriate to categorically exclude all plants from the BAT limitations merely because they may soon retire."[313]

Since EPA has not developed cost estimates for these units, it also did not do any analysis to assess how significant those costs may be compared to the unit's revenue, such as the screening analysis that EPA undertook for every other unit in the source category. This cost-to-revenue analysis and the subsequent IPM modeling are critical components of EPA's process for assessing whether a particular technology is economically achievable for the industry as a whole. Absent a unit-level cost assessment, and information on how those costs compared to the units' revenues, EPA has no basis to conclude that the technology it has selected as BAT for the rest of the category will not work for plants in this subcategory.

EPA also refers to concerns expressed by certain utilities regarded stranded assets for ELG treatment technologies installed relatively close to the end of the unit's useful life.[314] EPA does not cite to any particular examples of this, or other substantiation for these concerns. These concerns are relevant only for those units owned by vertically integrated utilities regulated by state public utility commissions, so even if these concerns were substantiated and legally relevant, they would not support subcategorizing merchant-owned coal units.[315] Vague concerns about plant owners being unable to obtain cost recovery are inadequate to defend the creation of a subcategory. Whether or not cost recovery will be allowed is a highly fact-dependent inquiry turning on, among other factors, the degree of the costs (unknown here due to EPA's failure to develop unit-level cost estimates, as noted above), the remaining useful life of the unit, and its economics relative to available alternative energy or capacity. It is not uncommon for regulators to determine that capital investments are justified during the last few years of a unit's planned useful life where the regulators conclude that better alternatives are not available. Indeed, even large expenditures may sometimes be approved. For example, in 2018, the Indiana Utility Regulatory Commission approved the Indiana Michigan Power Company's $274.2 million dollar expenditure to install selective catalytic reduction at Unit 2 of the Rockport plant, despite the company's lease interest in that plant terminating in 2022.[316] As evident above in the example of Pacificorp's expenditure on ELG compliance at the Dave Johnston plant, Pacificorp is clearly able to invest additional capital into these units despite their relatively short remaining useful life.

One recent case that commenters are aware of in which regulators denied recovery of ELG compliance costs reflects an extreme set of circumstances. The Commonwealth of Virginia State Corporation Commission denied recovery of costs for ELG compliance costs at two units at Dominion Energy Virginia's Chesterfield plant.[317] The Commission did so because at the time Dominion made the decision to retrofit the two units in question (mid-2015) and the utility was also undertaking analysis for an Integrated Resource Plan in which both of units were to be retired by 2020.[318] Consistent with this plan, operating staff for these units had also begun to avoid other major capital expenditures associated with life extension.[319] By the time the Commission was considering whether to allow costs, the units in question had already been placed on cold storage—an inactive reserve status.[320] Thus, the Commission concluded that the new equipment was not used and useful. This is a different situation from a plant that seeks to install treatment technology that will be used for multiple years.

EPA also did not evaluate the potential for units retiring by 2028 to lease treatment equipment to avoid significant capital expenditures. The record demonstrates that several vendors of FGD wastewater treatment technologies provide customers with the ability to lease equipment rather than purchasing it.[321] Other vendors may also be able to lease treatment systems to serve facilities that wish to avoid large capital costs; the record does not show that EPA has comprehensively assessed which treatment systems could be leased. The opportunity to lease equipment would largely eliminate the problems EPA has suggested regarding stranded costs and the need to recover capital costs over relatively short periods of time.

[308] See Section XIII – Benefits.
[309] See ERG, Steam Electric Effluent Guidelines Reconsideration – Evaluation of Potential Subcategorization Approaches, at 4 Tbl. 2, Docket ID No. EPA-HQ-OW-2009-0819-7911 (Aug. 29, 2019).
[310] IPM Cost Inputs for Baseline Scenario, Docket ID No. EPA-HQ-OW-2009-0819-8166.
[311] California Public Utility Commission, PacifiCorp California General Rate Case, Application 18-04-002; Exhibit Accompanying Direct Testimony of Shelly E. McCoy, at Page 8.5.24 (Project Description: "DJ UO ELG Install Bottom Ash Disposal System U1-3") (attached).
[312] EPA Response to Comments on ELG for Steam Electric Power Generating Point Source Category, at 3-548, Docket ID No. EPA-HQ-OW-2009-0819-6469 (Sept. 2015).
[313] Id.
[314] 84 Fed. Reg. at 64,640.
[315] According to our analysis, 14 of the 66 units in this subcategory are merchant. See Attachment: Units in 2028 Subcategory (attached).
[316] Indiana Utility Regulatory Commission Cause No 44871, Verified Petition of Indiana Michigan Power Company (I&M), an Indiana Corporation, for Approval of a Clean Energy Project and Qualified Pollution Control Property and for Issuance of Certificate of Public Convenience and Necessity for use of Clean Coal Technology; for Ongoing Review; for Approval of Accounting and Ratemaking, Including The Timely Recovery of Costs Incurred During Construction and Operation of Such Project, Order of the Commission issued Mar. 26, 2018 (attached).
[317] Commonwealth of Virginia State Corporation Commission, Petition of Virginia Electric and Power Company For Approval of a Rate Adjustment Clause designated Rider E, for recovery of costs incurred to comply with state and federal environmental regulations pursuant to §56-585.1 A 5 e of the Code of Virginia, Case No. PUR-2018-00195, Final Order issued Aug. 5, 2019, http://www.scc.virginia.gov/docketsearch/DOCS/4%243v01!.PDF (attached).

[318] Id. at 6-8.
[319] Id. at 7-8.
[320] Id. at 6.
[321] See ERG, Memorandum from ERG to Steam Electric Rulemaking Record, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367 (Oct. 22, 2019), at M-2, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019) (notes potential to lease Purestream AVARA mechanical vapor recompression modules); ERG, Notes from Meeting with Pall Water, at 3, Docket ID No. EPA-HQ-OW-2009-0819-7613 (Aug. 9, 2019) (noting availability of mobile membrane systems for lease).

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b. EPA's assertion that units in this subcategory might retire earlier if subject to the ELGs is baseless

Although EPA has not even developed costs or cost-to-revenue information for these units, it takes the next step to express concern that units in this subcategory might retire earlier than planned in order to avoid ELG compliance costs. EPA relies upon a crude survey in which unit owners self-reported the basis for retirements, and fewer than a third cited environmental regulations as one contributing factor.[322] From this, EPA concludes that "additional flexibility may help to avoid premature closures for some facilities and/or boilers."[323] As explained above, avoiding closures is not a valid objective for EPA to consider when establishing ELGs. Such closures are only "premature" if one ignores the Clean Water Act's mandates to develop BAT-based standards, which EPA has long failed to implement with respect to steam electric generating units. And of course, the "flexibility" to which EPA refers here is a euphemism for a full exemption from any requirements to reduce toxic water pollution from these facilities.

Even if avoiding retirement were a valid objective, EPA has not even shown that units in this subcategory would retire earlier than currently scheduled in order to avoid ELG costs. The fact that units have announced retirement dates after the "no later than" ELG compliance date suggests that those units have already factored ELG compliance costs into their decision about when to retire.[324] Presumably, if the ELG costs were going to be significant for those units, they would have already announced retirements before the "no later than" ELG compliance date.

The survey results upon which EPA relies show that environmental regulation compliance costs were far from the most significant contributing factor to retirements.[325] It is absurd for EPA to rely upon such self-interested and self-reported survey results when it has at its disposal, but has failed to use, far more sophisticated methods to assess whether imposing ELG compliance costs on units will cause earlier unit retirement. As noted above, EPA decided not to undertake updated IPM analysis that would have allowed the public to understand the retirement impacts requiring units in this subcategory to comply with ELGs based on a more stringent BAT.

However, EPA's 2015 assessment showed that the final rule option selected at that time would result in a net reduction of 843 MW in generating capacity as of the model year 2030.[326] This reflects less than 0.1% of total generating capacity in the United States, and only 0.3% of installed coal capacity.[327] In other words, EPA previously determined that the 2015 rule was unlikely to drive more than de minimis retirements. This evidence undermines EPA's case that units in this subcategory would accelerate their retirements in order to avoid ELG compliance costs, especially where EPA's preferred Option 2 would make the ELGs less stringent.

[322] 84 Fed. Reg. at 64,640.
[323] Id.
[324] Those requirements have been well-known since September 2015, and in effect except for several months in 2017.
[325] 84 Fed. Reg. at 64,640 (74 out of 107 facilities did not cite environmental regulation as even one among several contributing causes).
[326] Id. at 64,643.
[327] U.S. Energy Information Administration, Electricity explained, https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php ("At the end of 2018, the United States had about 1,097,859 MW—or 1.1 billion kilowatts (kW)—of total utility-scale electricity generating capacity. . . "); id. (noting that coal comprised 22% of electricity generating capacity in 2018).

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3. Increasing the use of the CCR rule's alternative closure provision is not a valid basis to establish this subcategory

EPA offers an additional justification for the 2028 subcategory – that it "would ensure that facilities could make better use of the CCR rule's alternative closure provision, by which an unlined surface impoundment could continue to receive waste and complete closure by 2028."[328] EPA fails to explain why it assumes that the alternative closure provision is generally: (1) available to units retiring by 2028, or (2) desirable to promote.

The alternative closure provision in the CCR rule is currently available only to facilities that can establish that disposal options are physically unavailable, not merely relatively expensive to access.[329] Although EPA has proposed to expand the availability of the alternative closure provision through the recently proposed Part A rule, this expansion is still subject to public comment and a final decision from EPA – and thus is far from assured. While the date upon which a facility ceases to receive waste is relevant to its eligibility for the alternative closure provision, EPA appears to be ignoring the current requirement that the operator of the CCR impoundment also show that safer disposal sites are physically unavailable.

Second, EPA's apparent intent to promote the use of the less-protective alternative closure provision is perverse, as it would undermine the CCR rule's protections against potential harm to health and the environment. Here, EPA seems to be encouraging more plants to take advantage of what was originally designed as a narrow exemption intended for plants where it would not have been physically possible for them to continue operating without an extension of the impoundment closure deadline. Indeed, it seems that rather than touting the increased use of the alternative closure provision as a result of this subcategory, EPA should be noting the negative non-water quality environmental impacts associated with creating this subcategory,[330] because increased use of alternative closure provision will increase risks of exposure to toxic pollutants in coal combustion residual wastes disposed of in unlined impoundments, including increased risk of groundwater contamination and catastrophic impoundment failures.

[328] 84 Fed. Reg. at 64,641.
[329] See 40 C.F.R. § 257.103(a), (b); see also *Util. Solid Waste Activities Grp. v. EPA*, 901 F.3d 414 (D.C. Cir. 2018) (confirming that costs are an impermissible factor under RCRA Subtitle D).
[330] CWA § 304(b)(1)(B), 33 U.S.C. § 1314(b)(1)(B).

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Moreover, EPA could have, but did not, decline to establish BAT for this subcategory and leave the matter to the judgment of individual state or federal permitting authorities. EPA determined that doing so would be "problematic" because the "technologies a permitting authority would necessarily consider are the same systems that result in unacceptable disproportionate costs according to the EPA's analysis."[336] But EPA's record is devoid of analysis of the cost for units in this subcategory to install any of the possible treatment technologies that would be more effective than surface impoundments. For instance, EPA does not evaluate the costs of using chemical precipitation to reduce the pollutants in FGD wastewater, or the availability of leased treatment systems to minimize or eliminate the upfront capital costs. Without any such analysis, EPA has improperly determined that the costs are "unacceptable," and then takes the next step of depriving state or federal permitting authorities from making a more nuanced case-by-case determination.

By establishing a weak and unsupported BAT determination for the units in this subcategory, EPA presumes that a state permitting authority could not find it feasible for a particular plant to install additional technologies to reduce its water pollution for the years it remains in operation. But as EPA has previously explained, site-specific factors can significantly change this question of feasibility. It is therefore inappropriate for EPA to set BAT for this subcategory based on the weakest possible treatment system available. Even if EPA is unwilling to do the analysis on what reasonably modern treatment systems might present "acceptable" costs for these units, it should not deprive state or federal permitting authorities of the ability to do so.

[336] 84 Fed. Reg. at 64,639.

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Comment Excerpt:

C. EPA's Subcategory for Boilers Retiring by 2028 is Not Practically Enforceable.

EPA is proposing a new subcategory for boilers with a "limited remaining useful life," which the agency defines as those boilers whose owners say that they intend to close them no later than December 31, 2028.[337] Not only is this proposed subcategory unjustified and unlawful, as described in these comments, it is also not practically enforceable.

EPA's proposed subcategory for boilers retiring by 2028 does not include any provisions that would prevent power plant owners or operators from delaying or withdrawing their plans to retire by 2028. EPA is proposing that facilities seeking this subcategorization make the request as part of the permit renewal or re-opening, submit a one-time certification to the permitting authority stating the date of expected retirement, and provide a citation to any filing, such as an integrated resource plan, or other documentation in support of that date.[338] According to EPA, this requirement of citation to any filing or other documentation is meant to provide the permitting authority with further evidence that a boiler will actually cease the production of electricity by the indicated date.[339] However, EPA is not proposing any type of enforcement mechanism nor is it proposing any type of ongoing reporting or recordkeeping requirement that goes beyond this proposed one-time certification. In contrast, for the proposed subcategory for boilers with low utilization, EPA is proposing tiered limitations for facilities that exceed the two-year net generation requirements as measured per calendar year.[340] Under EPA's proposed implementation of the low utilization subcategory, if a facility reports it exceeded the two-year average net generation of 876,000 MWh for a unit and no longer qualifies for the subcategory, it would automatically have two years until it must comply with a second set of limitations for discharges of FGD wastewater and bottom ash transport water, which are the effluent limits established for units that are not subject to any of the proposed subcategories.[341] Additionally, in contrast to the proposed retirement subcategory, EPA is proposing that all facilities with units subject to the low utilization subcategory be required to annually recertify that the units meet the requirements of the subcategory.

1. EPA Must Make Retirement Commitments for the Proposed Subcategory Federally Enforceable.

Although we strongly oppose EPA's new proposed subcategories, if EPA finalizes a subcategory for boilers whose owners say they intend to retire them by 2028, the agency must make the retirement commitments federally enforceable by including mechanisms that would prevent power plant owners or operators from delaying or withdrawing retirement plans that would no longer qualify the boilers for the subcategory.[342] The Clean Water Act requires effluent limitations established in ELGs to be federally enforceable.[343] Therefore, if a unit no longer qualifies for the subcategory, EPA must include provisions that would automatically subject the unit to the effluent limits established for units that are not subject to any subcategory, immediately. If a facility includes a retirement subcategorization request as part of a permit renewal or re-opening, the permitting authority should include tiered limitations (like EPA is proposing for the low utilization subcategory) in the facility's permit. In order to ensure that boilers no longer planning to retire by 2028 are immediately subject to the second set of limitations, EPA should require that plant owners notify the permitting authority that it no longer intends to retire the unit by 2028 as soon as they publicly report this information in any forum, such as to the public utility commission or investors. The permit should also include a provision that if such information is not reported but the unit continues to operate beyond December 31, 2028, the unit is immediately prohibited from all discharges of FGD and/or bottom ash wastewater, as applicable.

These requirements would not only make the facility's retirement commitment federally enforceable, they would also be in line with other EPA regulations that established exemptions or different numeric limits based on retirement or closure dates.

a. Other EPA regulations require standards or limitations based on retirement or closure dates to be federally enforceable.

i. The Boiler MACT Rule

In the Boiler MACT Rule,[344] EPA established federally enforceable numeric limitations for subcategories of industrial boilers that emit hazardous air pollutants. The Clean Air Act's hazardous air pollutant provisions are similar to the ELG provisions of the Clean Water Act. Under Section 112 of the Clean Air Act, EPA must set a national emission standard for each category or subcategory of "major sources" of "hazardous air pollutant" emissions.[345] In 1990, Congress amended Section 112 to require technology-based standards—or "maximum achievable control technology"—based on a two-step process. First, EPA identifies a MACT floor for each pollutant and source category – that is, "the average emission limitation achieved by the best performing 12 percent of the existing sources" or, if there are fewer than 30 sources, "the average emission limitation achieved by the best performing 5 sources."[346] In the second step, EPA selects as its technology-based standard either the applicable MACT floor identified in the first stage or a more stringent, beyond-the-floor limitation if such a standard is "achievable" in light of costs and other factors and methods.[347] EPA considers, among other factors, whether emissions can be reduced through "process changes," treatment, design or work practices, or other methods of control; the cost of achieving such emission reduction; any non-air quality health and environmental impacts; and energy requirements.[348]

Based on those statutory factors, EPA established numeric limitations for several categories and subcategories of industrial boilers that emit hazardous air pollutants, including a subcategory for "[l]imited-use boilers and process heaters," which are any boilers or process heaters that burn "any amount of solid, liquid, or gaseous fuels *and has a federally enforceable* annual capacity factor of no more than 10 percent."[349] Limited use boilers are exempt from the numeric hazardous air pollutant standards applicable to other boilers.[350] In order to qualify for the limited use subcategory, the source must accept a "federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent."[351]

ii. The ACE Rule

Although the Affordable Clean Energy (ACE) Rule does not contain a per se exemption for retiring sources, it does allow states to "take into consideration factors, such as the remaining useful life of such source," in establishing the best system of emission reduction.[352] EPA included that provision, in part, because Section 111(d) of the Clean Air Act explicitly requires EPA to "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, *among other factors, the remaining useful life of the existing source to which such standard applies.*"[353] The visibility provisions of the Clean Air Act include the same "remaining useful life" consideration as a factor in evaluating "best available retrofit technology" or additional pollution reductions necessary to make "reasonable progress" toward natural visibility.[354] Under both regulatory regimes, if a state opts not to require emission reductions because of a reduced operating capacity or retirement commitment, the state must include any such retirement or reduced-capacity commitment in a federally enforceable permit or a state implementation plan.[355] Similar to the Clean Air Act's requirements that all aspects of state implementation plans be federally enforceable, the Clean Water Act requires effluent limitations established in ELGs to be federally enforceable via NPDES permits.[356]

iii. The CCR Rule

The Coal Combustion Residuals (CCR) Rule also contains an exemption for boilers that cease operations by a date certain, which is based on specific statutory language in the Resource Conservation and Recovery Act (RCRA).[357] Similar to the Clean Air Act rules above, the CCR Rule requires these retirement commitments to be federally enforceable. Under the CCR Rule, a landfill or impoundment may continue to receive coal ash "if the owner or operator certifies that the facility will cease operation of the coal-fired boilers within" certain timeframes (2021, 2023, or 2028) depending on the size and type of the CCR unit.[358] To qualify for the exemption, the operator must also (i) document that no alternative disposal capacity is available; (ii) remain in compliance with all other requirements of the Rule, including the requirement to conduct any necessary corrective action; and (iii) prepare an annual progress report documenting the continued lack of alternative capacity and the progress toward the closure of the coal-fired boiler.[359] The operator must also complete the required, federally enforceable notice and documentation requirements by a date certain.[360]

b. EPA should not finalize subcategories that do not have federally enforceable limitations.

EPA is soliciting comments on whether this subcategory would incentivize coal-fired boilers that were not otherwise planning to retire by 2028 to accelerate their retirement to 2028.[361] EPA's request for comment on this potential incentive underscores the need for this proposed subcategory to be enforceable. If some plant owners may only be choosing to retire certain units by 2028 to take advantage of the weaker limits for the subcategory, it is reasonable to assume that those plant owners would be at risk of delaying or withdrawing their retirement decisions if the rule does not require a firm retirement commitment in order to qualify for the subcategory. We commend EPA for drawing a distinction between involuntary and voluntary withdrawals[362] and recommend that EPA maintain both this distinction and the agency's use of the savings clause if the retirement subcategory is finalized. However, if the retirement subcategory is finalized, EPA must go further and require that all retirement commitments, as they relate to subcategory qualification, be federally enforceable and included in the operator's NPDES permit.

2. EPA should revise the proposed rule's implementation requirements for the retirement subcategory.

Furthermore, similar to the requirements for the proposed low utilization subcategory, EPA should include a reporting requirement that plant owners "annually recertify that the boiler continues to meet the requirements of this subcategory" [363] rather than the one-time certification EPA is proposing. As a part of the annual recertification process, EPA should require that plant owners seeking the retirement subcategorization identify the timeline of steps they believe to be necessary to finalize retirement of a unit and provide updates on the retirement process during each recertification. According to EPA, the agency has set the retirement date for this subcategorization as 2028 in order to allow plant owners and operators enough time to take the steps EPA believes are necessary to complete deactivation, such as modifications to integrated resource plans, requests for approval of any necessary replacement generation, and evaluation of the need for any transmission system upgrades needed to allow deactivation.[364] If the agency and plant operators identify these steps and a timeline that they deem appropriate, EPA should require that operators document the progress made toward retirement of the units in their annual recertification in order for the units to maintain eligibility for the subcategory. Additionally, the agency should also require that plant operators have already submitted a deactivation request to the system operator or other relevant authority by the time they seek this subcategorization. The filings or other documentation that EPA cites are not likely to be binding or enforceable, and the information included in such documentation may be altered in future filings. By requiring that plant operators submit a deactivation request and annually recertify that their units meet the requirements of the subcategory, EPA will be requiring operators to take the necessary steps to ensure there will be no unforeseen or unexpected causes for delayed or withdrawn retirements.

In summary, EPA should not finalize a subcategory for boilers retiring by 2028 because the proposed provisions are unenforceable and, therefore, invalid under the Clean Water Act. If EPA intends to finalize the proposed retirement subcategory, the agency must ensure that the retirement commitments are federally enforceable by requiring that tiered limitations, which would be applied immediately if a unit no longer meets the requirements of the subcategory, be included in the plant's NPDES permit. Furthermore, EPA should require that plant operators have already submitted a deactivation request by the time they make a subcategory request and annually recertify that their units meet the requirements of the subcategory while also documenting the progress made towards retirement of the units.

[337] 84 Fed. Reg. at 64,640.
[338] Id. at 64,667.
[339] Id.
[340] Id. at 64,666.
[341] Id.
[342] The Clean Water Act authorizes EPA to prescribe conditions of NPDES permits "as the Administrator determines are necessary to carry out the provisions of this chapter." 33 U.S.C. § 1342(a)(1)-(2).

343 Effluent limitations must be based on ELGs promulgated by EPA. See id. § 1311(b). Effluent limitations become federally enforceable at a particular facility when they are incorporated into a NPDES permit. See id. §§ 1342, 1319.
344 Codified at 40 C.F.R. Part 63, Subpart DDDDD.
345 42 U.S.C. § 7412(d)(1).
346 Id. § 7412(d)(3).
347 Id. § 7412(d)(2).
348 Id.; *see generally Cement Kiln Recycling Coal. v. EPA,* 255 F.3d 855, 857-58 (D.C. Cir. 2001) (per curiam) (explaining two-step MACT process for hazardous waste combustors); *Nat'l Lime Ass'n v. EPA*, 233 F.3d 625, 628–29 (D.C. Cir. 2000) (explaining two-step MACT process for Portland cement manufacturing plants); *Nat. Res. Def. Council v. EPA*, 489 F.3d 1250, 1254 (D.C. Cir. 2007) (boiler MACT litigation).
349 40 C.F.R. § 63.7575 (emphasis added).
350 Id. § 63.7500.
351 Id. § 63.7555(a)(3); see also 78 Fed. Reg. 7138 (Jan. 31, 2013).
352 40 C.F.R. § 60.24a(e).
353 42 U.S.C. § 7411(d) (emphasis added).
354 Id. § 7491(g)(1)-(2).
355 40 C.F.R. Part 51, App'x. Y § IV(D)(4)(d)(1) (BART Guidelines: where a utility projects that future operating parameters (e.g., limited hours of operation or capacity utilization) "will differ from past practice, and if this projection has a deciding effect in the BART determination," then the state must" make those operating parameters or assumptions into enforceable limitations"); id. § IV(D)(4)(k) (BART Guidelines requiring a federally-enforceable provision assuring the date on which a source permanently stops operations); 84 Fed. Reg. 32,520, 32,558 (July 8, 2019) ("It is important to note that (as with all aspects of the state plan) the standard of performance and associated retirement date will be federally enforceable upon approval by the EPA.").
356 See 33 U.S.C. §§ 1311(b), 1342, 1319.
357 EPA interprets RCRA's "integration" provision, 42 U.S.C. § 6905, to allow it to "reduce or eliminate RCRA requirements" so long as the agency demonstrates that the integration meets RCRA's protectiveness mandate. See 80 Fed. Reg. 21,302, 21,424 (Apr. 17, 2015) (citing *Chem. Waste Mgmt. v. EPA*, 976 F.2d 2, 23, 25 (D.C. Cir. 1992) (approving EPA rule that allowed temporary impoundment of diluted, previously-hazardous waste). In the final CCR Rule, EPA explained that it believed it could relax CCR requirements where other compliance with "other EPA statutes which may lead an owner or operator to close a coal-fired power plant." 80 Fed. Reg. at 21,424. The Clean Water Act does not include a similar provision, which suggests that CWA requirements cannot be reduced or eliminated based on retirement plans made in response to other statutes.
358 40 C.F.R. § 257.103(b).
359 Id.
360 Id. § 257.103(d) (citing 40 C.F.R. § 257.102(g), 257.105(i)); see also 80 Fed. Reg. at 21,309 ("states or citizens can enforce the requirements of this rule under RCRA's citizen suit authority.").
361 84 Fed. Reg. at 64,641.
362 Id. at 64,666.
363 Id. at 64,667.
364 See Docket ID Nos. EPA-HQ-OW-2009-0819-8274 & 8275.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 8

Comment Excerpt:

C. A Subcategory For Retiring Boilers Is Necessary To Avoid Stranded Costs And Unacceptably High Compliance Costs.

EPA is proposing to establish a new source subcategory for coal-fired boilers with a limited useful life that will retire by no later than December 31, 2028. These retiring boilers would only be subject to effluent discharge limitations for total suspended solids ("TSS") based on gravity settling through the use of surface impoundments for both FGD wastewater and BA transport water. These TSS limitations would apply in lieu of imposing significantly more stringent effluent discharge limitations based on chemical precipitation with biological treatment for reducing discharges of FGD wastewater, and dry ash handling or closed-loop wet ash handling system for reducing BA transport waters. Oglethorpe Power supports the proposed adoption of a new source subcategory for retiring boilers with the less stringent effluent discharge limitations for the following reasons.

First, market conditions in the electric power sector have shifted significantly over the past decade. These changes have included increased supplies of inexpensive natural gas and technological advances in solar, wind, and other renewable energy resources. As a result of these market trends, rate of coal-fired power plant retirements has accelerated in recent years and this trend of early retirements will most likely continue, if not increase, with the aging of the coal-fired generating fleet and the mounting pressures for electric power sector to reduce its carbon footprint.[5] The adoption of a new source subcategory for retiring units is necessary to avoid the potential for stranded costs that would be incurred by requiring these facilities to make major capital investments for pollution control equipment near the end of their useful life. Furthermore, it is appropriate exercise of EPA's standard-setting authority under section 304(b) of the CWA, which directs EPA to consider cost, the age of the equipment and facilities involved, and non-water quality environmental impacts (including energy requirements).

Second, retiring units would incur unacceptably high compliance costs if they were required to install the reference control technologies (as noted above) that were used for setting effluent discharge limitations for FGD wastewater and BA transport waters for the general source category. These disproportionately high costs would mainly be incurred due to the fact that a retiring unit would be unable to amortize major capital and O&M costs across the 20-year life of the newly installed control technologies (which was the time period that EPA used for justifying the cost effectiveness of the proposed effluent discharge limitations). This economic assessment was specifically confirmed by the Agency itself in both the preamble to the Proposed Rule and a technical support document. In particular, EPA determined that a retiring EGU "could be forced to pass on capital costs per MWh 10 to 15 times higher than those passed on with the assumed 20-year amortization in EPA's cost estimates, and the costs per MWh remain more than double the EPA's estimates until amortization of six to eight years, depending on the discount rate."[6]

Third, the imposition of these high compliance costs could accelerate the retirements of those coal-fired EGUs that are no longer being used as baseload generating units, particularly given that they are approaching the end or their useful life. The accelerated early retirement of significant amounts of existing coal-fired generating capacity could, in turn, increase the risk of electricity reliability problems. One notable study confirming these electric reliability risks is a recent North American Electric Reliability Corporation (NERC) report documenting through a "stress test scenario" assessment that significant reliability risks could result from the premature retirement of large coal-fired and nuclear facilities if those retirements were to occur faster than the construction of necessary replacement generating capacity.[7]

The proposed adoption of a new source subcategory for retiring coal-fired EGUs (with less stringent effluent discharge limitations) would address this concern by ensuring the orderly and well-planned replacement of such retiring units retirement with new generation, along with the necessary transmission and other ancillary electric infrastructure. In particular, it would allow the electric power sector to continue an organized, market-driven phasing out of coal-fired generating facilities that are no longer economical or reaching the end of their useful life, in favor of new highly efficient and low- or zero-emitting generating units without posing the electric reliability risks identified above in the NERC report.

5 84 Fed. Reg. at 64,640. See also Supplemental Technical Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Section 3, ("Supplemental TDD").
6 84 Fed. Reg. at 64,640. See also Supplemental TDD at Section 3.
7 North American Electric Reliability Corporation, Special Reliability Assessment: Generation Retirement Scenario (December 18, 2018). Available online at:
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%2ODLLIVERCRetirements_Report2018_Final.pdf
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Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 9

Comment Excerpt:

D. Clarification Is Needed On The Timeframe For Making An Election To Be Classified as a Retiring Unit.
The Corporation has a technical concern regarding the proposed timeframe by which owners or operators must make an election to retire their coal-fired boilers. This concern, which is similar to the one described above for low-utilization units in Section B, is the proposed deadline for submitting to the permitting authority the one-time certification statement that the boiler will be retired by December 31, 2028. In particular, the regulatory text in the Proposed Rule states that the certification "must be submitted with the permit application, or where a permit has already been issued, by the soon as possible date determined under paragraph 423.11(t)."[8] This requirement fails to specify any minimum date by when the submission must be made. Given that NPDES permits have already been issued to the vast majority of, if not all, existing generating facilities, one possible reading of the proposed regulatory text is that every owner or operator of a retiring boiler must submit its certification statement by November 1, 2020 (which is a deadline date that could precede the promulgation date of a final ELG rule) unless the owner or operator is able to secure an extension from the permitting authority (which may not be later than December 31, 2023). This approach is confusing and creates considerable uncertainty on what is the deadline for submission of the one-time certification statement to the permitting authority.

To clarify this situation, Oglethorpe Power recommends that EPA revise proposed section 423.19(f)(1) to require that the initial certification statement be submitted to the permitting authority by a date certain, specifically within three years from the promulgation date of the final ELG rule in the Federal Register.

Furthermore, the Corporation urges EPA to consider making several additional changes to improve the workability of the certification process for retiring units. These changes are briefly described below.

One important change is to simplify and streamline the certification process established in the Proposed Rule. Under the Proposal, the owner or operator of the retiring EGU must submit their most recent Integrated Resource Plan ("IRP") or other legally binding documentation confirming that the unit will in fact retire by December 31, 2028. As an alternative, we recommend that EPA require only the submission of a certified letter signed by a responsible corporate official in order to qualify a unit for the retirement provision. This certification is clearly sufficient on its own to legally bind the EGU owner or operator to retire the unit by the 2028 deadline. By contrast, the submission of an IRP or other documentary evidence serves no real purpose or function and unreasonably increases the paperwork burden on the retiring unit.

Second, EPA should provide additional flexibility by when the one-time certification must be submitted to the Agency. Oglethorpe Power recommends that the owner or operators of retiring EGUs should be allowed to submit the certification on retirement any time up to the final deadline established for complying with the new effluent discharge limitations (e.g., December 31, 2025 for FGD wastewater). Under this approach, EGU owners and operators would have the maximum timing flexibility to make important, and often complex, decisions on when it is possible to retire units in an orderly manner that poses no significant electric reliability risks and addresses other important resource planning concerns.

8 84 Fed. Reg. at 64,677 (citing proposed 40 C.F.R. §423.19(f)(1)).

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 10

Comment Excerpt:

A. The Proposed 2028 Retirement Deadline Should Be Retained At Minimum.
Oglethorpe Power believes that the retirement deadline of December 31, 2028 should not be shortened under any circumstances and, as discussed below, may warrant an extension to 2032. First of all, a long lead time is necessary to complete the design, permitting, financing, procurement, and construction of the necessary replacement generating capacity. Even under best case situations, building and bringing online the new generating facilities can take up to five or six years to complete. Additional time will sometimes become necessary due circumstances beyond the control of the electric utility. For example, lengthy project delays can frequently result from legal challenges to the permits or other federal, state, or local approvals that are typically necessary for construction of any major new generating facility.

In many cases, a project to build replacement capacity may also require the construction of other critically important energy infrastructure necessary to support the deployment of a new generating facility. Notable examples include the buildout of a natural gas pipeline and the necessary transmission lines for delivering the electricity from the new facility to the load centers. One notable case in point is the effort that has been underway for many years to build a new natural gas pipeline through West Virginia, Virginia, and North Carolina. Referred to as the Atlantic Coast Pipeline, this major energy infrastructure has been subject to lengthy construction delays due to various legal challenges to the many federal, state, and local permits and authorizations that are necessary for building a 600-mile underground pipeline across three states.

In addition, the proposed “safety valve” mechanism for extending the retirement deadline in the case of those generation facilities that fail to retire by 2028 is of little help. An extension would most likely not be available due to many circumstances that are beyond the control of the electric utility, such as major unexpected delays in the construction of the new replacement generating unit or other important infrastructure for the project (e.g., buildout of natural gas pipeline or transmission lines). Rather, the extension, as proposed, would be limited to only those cases in which the Department of Energy has issued an emergency order requiring continued operation of the EGU under section 202(c) of the Federal Power Act (“FPA”) or a public utility commission has issued a reliability must-run agreement. The issuance of such an emergency order or must-run agreement is infrequent and limited only to providing relief in emergency situations. As a result, EPA’s proposed safety valve provision would not serve as a reliable mechanism for extending the retirement deadline due to a wide range of extenuating circumstances that do not necessarily involve an emergency electric reliability problem meeting the stringent requirements for issuing a FPA section 202(c) order or a reliability must-run agreement.

For these reasons, the Corporation believes that a retirement deadline of December 31, 2028 is the absolute minimum amount of time that is needed to complete the orderly transition from the retiring unit(s) to new generating capacity. In addition, we urge EPA to consider developing another regulatory option, as described below in the next section, to extend the retirement deadline another few years until December 31, 2032.

9 84 Fed. Reg. at 64,641.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 11

Comment Excerpt:

B. EPA Should Create Another New Source Subcategory for Longer-Term Retirements To Support The Transition To New Fleet Of Cleaner and More Efficient Generating Resources.
As explained in the previous section, a retirement deadline of December 31, 2028 will most

likely not be sufficient to ensure an orderly transition for some coal-fired EGUs that may retire over the next decade. To address this concern, Oglethorpe Power urges EPA to establish a new source subcategory that would establish appropriate effluent discharge limitations for existing coal-fired EGUs that are scheduled to retire over the next decade (specifically units with a remaining useful life that is greater than eight years but less than twelve years).

One objective of this new source subcategory is to account for the transformation that is now underway in the electric power sector to close existing coal-fired power plants and transition to renewable energy and other low- and zero-emitting energy resources. Requiring electric utilities to incur major capital compliance costs to comply with stringent new effluent discharge limitations also does not make good policy sense for this class of retiring units. It could in fact hinder, rather than help to facilitate, an orderly and efficient transition to cleaner and more efficient electric generating resources in Georgia and other states. For example, the establishment of a hard retirement deadline could force some coal-fired plants to shut down earlier than planned in order to avoid incurring major stranded capital investments. Those premature plant retirements, in turn, could have both economic and electric reliability repercussions. In addition, it would be inconsistent with the requirements of the CWA[10] for EPA to establish effluent discharge limitations that are reasonable and economically achievable for all affected facilities within the particular source category.

Under this proposed approach of establishing a new subcategory of longer-term retiring EGUs, EPA would establish alternative effluent discharge limitations that would moderate the stringency of the limitations to ensure the reasonableness and economic achievability of the control requirements. These discharge limitations should be set on a case-by-case basis by the state or federal regulatory authority based on “best professional judgment” (“BPJ”) in order to reflect the variety of source-specific factors for ensuring the establishment of reasonably achievable and cost-effective control levels.

10 See e.g., Section 304(b) of the CWA.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 52

Comment Excerpt:

Moreover, EPA’s cost analysis is faulty because it purports to evaluate cost on the basis of individual units, rather than on an industry-wide basis, and because it contains no finding that the costs of treatment technology cannot be borne by the industry.

Market forces are driving plant retirements, as EPA admits: “As these changes happen in the industry, the electric power infrastructure adjusts and generally trends toward the optimal infrastructure and operations . . . .”[136] Utilities, not EPA, are positioned to decide how best to meet the needs of their customers. EPA should not gut existing regulations in an attempt to prolong the life of outdated, polluting, and uneconomical coal-fired power plants. If water quality protections are required, as they are here, it is utilities' job to comply while ensuring they meet their demand.

Duke Energy's Allen power plant on Lake Wylie in North Carolina illustrates the problems with this exemption. The plant would be eligible for the proposed exemption: Duke Energy previously planned to fully retire all coal generating units at Allen by 2028, and recently accelerated that schedule to 2024. But Duke Energy already has installed a high-residence-time bioreactor for its FGD wastewater, and has a current NPDES permit with the current BAT effluent limits.[137] Moreover, Duke is required to excavate its unlined impoundments at Allen to lined landfill storage.

However, EPA's proposal would allow the Allen facility to avoid complying with strict, enforceable pollution limits. The company is currently trying to undo the technology-based effluent limits in its permit for the Allen facility.[138] If EPA provides this early retirement exemption, it is clear that Duke Energy will take advantage of the opportunity to avoid enforceable pollutant limits for the remaining life of the plant—even though the treatment technology necessary to comply is in place now. Duke Energy is required to eliminate the impoundments at Allen, but with no enforceable limits in place, there would be no guarantee that Duke Energy will operate its FGD wastewater treatment system effectively, or even operate it at all. The public would be deprived of the protections that Congress mandated with the Clean Water Act. EPA must avoid this absurd outcome.

[136] 84 Fed. Reg. at 64,626.
[137] Attachment 30.
[138] Attachment 28.

Commenter Name: Megan Kimball
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Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 53

Comment Excerpt:

Numerous facilities around the region also demonstrate that early retirement is compatible with modern ash handling and pollution controls. For example:

- In Virginia, Dominion contemplates retiring all of the coal units at its Chesterfield plant by 2023, as set out in the section of its IRP listing "retirement assumptions used for planning purposes."[139] The company has already converted Chesterfield (and all its other coal plans in Virginia) to dry ash handling.
- In South Carolina, Santee Cooper has committed to retire all four coal units at its Winyah power plant by 2027 (Units 1 and 2 in 2023, 3 and 4 in 2027),[140] and has already stopped using its unlined coal ash lagoons.

- Georgia Power has indicated it plans to retire Plant Bowen Units 1 and 2 prior to Dec. 31, 2028.[141] The company has already installed dry ash handling systems at the plant.

These facilities illustrate that much more effective waste handling technologies are available for retiring plants; unlined impoundments are manifestly not the best available technology. And in addition, if EPA implements the proposed exemption, it will contravene the Clean Water Act by removing enforceable requirements from facilities like these that have the technology already in place to meet more protective limits. Far from helping these utilities, EPA will be harming them in the eyes of investors and stock analysts by letting other utilities off the hook without having to incur the same expenses.

[139] Dominion IRP at 48 (Appendix 3J) (Attachment 46).
[140] Santee Cooper, Santee Cooper Business Forecast, 3 (Sept. 9, 2019), available at https://www.santeecooper.com/About/Business-Forecast/_pdfs/2019-09-09-Santee-Cooper-BusinessForecast.pdf,(Attachment 47).
[141] Georgia Power Company, 2019 Integrated Resource Plan Doc. Filing #175473, Main Doc filed before the Georgia Public Service Commission January 31, 2019, 1-7 available at https://psc.ga.gov/search/factsdocument/?documentId=175473 (PD 2019 IRP, Main Doc, 2019 IRP Main Document) (Attachment 48).

Commenter Name: Josh Shapiro, Brian E. Frosh, Kwame Raoul, Dana Nessel, and Thomas J. Donovan, Jr.
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Document Control Number: EPA-HQ-OW-2009-0819-8323-A1
Comment Excerpt Number: 6

Comment Excerpt:

B. EPA's Proposed Subcategorization of End-of-Life Boilers Is Arbitrary and Capricious.
EPA's proposal to create a more lenient subcategory for boilers whose owners claim they will retire by December 31, 2028, see 84 Fed. Reg. at 64,640-41, is arbitrary and capricious. EPA's primary rationale seems to be that these owners should not have to invest in equipment or technology necessary to meet more stringent effluent limitations if the costs of investments cannot be spread over a long enough period. See id. at 64,640. To the extent that EPA's position is that an overly short amortization period could cause power plants to accelerate their timeline for closing, the ELG Proposal offers nothing to elevate this possibility (much less the possibility of meaningful impacts on grid reliability) beyond the realm of mere speculation. See id. (citing study "identifying the reliability risks if large baseload coal and nuclear facilities were to bring their projected retirement dates forward," and noting that "this stress test is not a predictive forecast" (emphasis added)); id. (stating generally that "additional flexibility may help to avoid premature closures for some facilities and/or boilers").

Further, to the extent that these investments merely make a power plant less profitable to operate in the years before it closes, EPA does not explain why it is fair to require the public to bear the costs of the pollution that results from subjecting the boiler to less stringent effluent limitations.

Notably, the ELG Proposal itself admits that surface impoundments—the proposed BAT basis for boilers retiring by 2028—"are not as effective at controlling pollutants like dissolved metals and nutrients as available and achievable technologies like [chemical precipitation] and [low hydraulic residence time biological reduction]." 84 Fed. Reg. at 64,634.

Those boilers whose owners currently intend to retire them by 2028, moreover, may be among those for which robust water pollution controls are particularly urgent. If closure is on the horizon for these boilers, they may have forgone the sorts of improvements that are more likely when a plant is relatively early in its life. Not only that, but their expected imminent closure suggests that they are already economically marginal, potentially giving their owners a further incentive to cut corners when it comes to pollution controls. One cause of a plant's economically marginal status, moreover, may be its relative inefficiency—i.e., its reliance on more coal to generate a particular amount of energy.

No more persuasive is EPA's statement that subcategorization of boilers expected to retire by 2028 "would ensure that facilities could make better use of the CCR rule's alternative closure provision, by which an unlined surface impoundment could continue to receive waste and complete closure by 2028." 84 Fed. Reg. at 64,641. That rationale amounts to a kind of polluter friendly bootstrapping: the alternative closure provision is broadly available only because EPA has chosen to make it so, out of a concern about the need to develop alternative capacity. It verges on the absurd for EPA to now use the provision to justify measures that increase the amount of waste routed to surface impoundments in the first place. That rationale strongly suggests that creating this less-regulated subcategory is just a subsidy for non-economical, dirty plants that may have been benefiting from other regulatory rollbacks already. See, e.g., id. at 64,625 (discussing replacement of Clean Power Plan with Affordable Clean Energy rule).

Further, even if a facility declares its intent to close by 2028, that stated intent remains unenforceable: the ELG Proposal does not prevent a facility owner from announcing that it will close by 2028, but then changing its mind as that date approaches. See 84 Fed. Reg. at 64,666. EPA does seem to envision that, in such circumstances, the facility owner may become subject to more stringent effluent limitations. See id. (stating that a facility that voluntarily withdraws or delays its retirement "should carefully plan its implementation of the ELGs"). But in the meantime, the facility will have operated under inappropriately lax effluent limitations for years. And the ELG Proposal seems to offer facilities yet another way out: in the case of retirement delays or withdrawals resulting from "involuntary orders and agreements," a savings clause in permits "would protect a facility which involuntarily fails to qualify for the subcategory . . . , and would allow that facility to prove that, but for the order or agreement, it would have qualified for the subcategory." Id. The existence of such a savings clause improperly creates an incentive and opportunity for facility owners to characterize delayed or withdrawn retirements as "involuntary" when they are anything but that.

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Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 2

Comment Excerpt:

2. EPA's grandfathering provision for boilers retiring by 2028 creates harmful incentives to delay compliance with the guidelines and is arbitrary and capricious.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 10

Comment Excerpt:

Finally, EPA justifies its "retiring by 2028" subcategory by claiming that less costly standards will avoid burdening utilities with "stranded assets" and will forestall premature facility retirements.[69] Yet again, EPA does not consider the health or environmental costs of this individual BAT decision. This omission is especially significant because a laxer BAT will not only increase pollution during the operation of these boilers, but will also, according to EPA, increase the amount of time these boilers operate[70] and thus extend the boilers' contribution to water pollution, air pollution, and climate change. Again, the agency violates its statutory obligation to consider whether its proposed BAT for boilers retiring by the end of 2028 is truly "best" at making progress toward eliminating the discharge of all pollutants, or whether the BAT has an unacceptable "non-water quality environmental impact."

69 Id. at 64,640.
70 See id. (justifying the decision in terms of avoiding the result of facilities "bring[ing] their projected retirement
dates forward").

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 14

Comment Excerpt:

B. EPA's Fixation on Cost Is Irrational, Even by the Agency's Own Logic
To the extent EPA attempts to explain its narrow focus on compliance cost, the agency

undermines its own justification.

EPA casts its concern with compliance costs in terms of avoiding premature facility retirements. When discussing the market conditions of the electricity generation sector, for example, EPA stresses that "negative distributional effects can be particularly difficult for communities affected by company decisions to scale back or retire a facility."[75] As detailed above, to justify its new subcategories for high flow facilities and low utilization boilers, the agency emphasizes that the 2015 Rule put such plants at a competitive disadvantage that could result in closures.[76] To explain the new subcategory for boilers retiring by 2028, the agency cites data from "the North American Electric Reliability Corporation [which] recently conducted an aggressive stress test scenario identifying the reliability risks if large baseload coal and nuclear facilities were to bring their projected retirement dates forward."[77] The implication throughout the Proposed Rule is that laxer standards will prevent premature facility retirements.

Yet EPA's own analyses belie the claim that this Proposed Rule will have a meaningful effect on plant retirements; the evidence shows that the plants will retire anyway. EPA notes that the "lower cost of natural gas and technological advances in solar and wind power have had a depressive effect" on coal plants.[78] Elsewhere in the Proposed Rule, EPA notes that "the most frequently stated reason" for facility and boiler retirements is "market forces, such as the continued low price of natural gas."[79] In its Regulatory Impact Analysis, the agency cites a study finding that 92% of decline in coal production can be explained by the decrease in natural gas prices, while environmental regulations account for only 6% of the decline.[80] Perhaps most tellingly of all, EPA's own cost projections predict that the Proposed Rule would yield minimal change for the rate of coal plant retirement relative to the 2015 Rule.[81]

Thus, the Proposed Rule is internally inconsistent about whether the changed regulations can be expected to meaningfully prevent retirements. The Courts have found that agencies may not rely on internally inconsistent arguments without explanation to support a regulation.[82] Such reliance,

according to the Supreme Court, is arbitrary and capricious.[83] To the extent EPA attempts to use the specter of facility retirement as justification for its lax standards, the justification fails.

75 Proposed Rule, 84 Fed. Reg. at 64,626.
76 Id. at 64,638–39.
77 Id. at 64,640.
78 Id. at 64,626.
79 Id. at 64,640.
80 RIA at 2-10.
81 Id. at 5-6 to 5-8.
82 Encino Motorcars, LLC v. Navarro, 579 U.S. —, 136 S. Ct. 2117, 2126 (2016); Nat'l Cable & Telecomm. Ass'n v. Brand X Internet Servs., 545 U.S. 967, 981 (2005) ("Unexplained inconsistency is . . . a reason for holding an interpretation to be an arbitrary and capricious change."); Gen. Chem. Corp. v. United States, 817 F.2d 844, 857 (D.C. Cir. 1987) (deeming agency conclusion arbitrary and capricious where supporting analysis was "internally inconsistent").
83 Encino Motorcars, 136 S. Ct. at 2126 ("[A]n 'unexplained inconsistency' in agency policy is 'a reason for holding
an interpretation to be an arbitrary and capricious change from agency practice.'") (internal quotation omitted).

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law

Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 15

Comment Excerpt:

III. EPA's Grandfathering Provision for Boilers Retiring by 2028 Creates Harmful Incentives to Delay Compliance with the Guidelines and Is Arbitrary and Capricious.

The Proposed Rule allows boilers retiring by the end of 2028 to continue using surface impoundments as the BAT/PSES for flue gas desulfurization wastewater and bottom ash transport water,[84] rather than meeting the effluent limitations guidelines prescribed for the category as a whole. The agency also solicits comments on providing the same extension to "boilers that are planned to be repowered or replaced by 2028."[85]

The grandfathering provision is unjustified, and EPA has not provided an adequate justification for the harms that it will cause. Legal and economic scholars have long recognized that stringently regulating new sources of pollution while exempting existing sources—a regulatory practice commonly known as "grandfathering"—can perversely encourage those existing sources to stay in operation longer than they otherwise would, lead to adverse environmental consequences, and impair social welfare.[86] Academics call this distortion of retirement decision the "old plant effect."[87] One well-known example of this effect is provided by the Clean Air Act of 1970, which set laxer standards for existing sources of pollution than for new sources.[88] This age-based bifurcation encouraged facility owners to continue operating old plants, rather than replacing them with new plants subject to stricter environmental standards.[89] Although prior to the Clean Air Act's passage, the economically useful life of a coal plant was considered to be thirty years, by 2012, more than three quarters of the nation's plants had been operating for longer.[90] Forty percent of the plants were more than 40 years old, and 20 percent were more than 50 years old.[91] These old plants account for a disproportionate share of the nation's pollutants, in some cases emitting two-to-four times as much pollution as newer sources.[92]

The Proposed Rule falls victim to the classic problems associated with grandfathering. As discussed in Part II.B above, by EPA's own account, there is reason to doubt that the Proposed Rule will meaningfully prevent plant retirements. But if the grandfathering provision achieves its stated purpose, this provision will encourage old boilers that would otherwise retire within the coming years because of compliance costs to continue operating until at least 2028. This allows such boilers to continue polluting at high rates for a longer period of time. Rather than repowering or replacing boilers earlier with newer, more efficient models, facilities would have incentive to wait until 2028 to make such replacements, again prolonging the public's exposure to high-polluting boilers.

But even more troublingly, this grandfathering policy has no penalties built in for boilers or facilities that do not in fact retire by 2028, but instead "withdraw" their plans to retire and continue operating. This is a critical omission, because plant owners commonly claim they will retire plants or boilers and then renege if conditions change. In fact, EPA acknowledges in the Proposed Rule that there are "several instances when facilities have withdrawn or delayed retirement announcements for coal-fired boilers and facilities."[93]

EPA deals with the possibility of continued operation in two ways. For plants that continue operating involuntarily—because of regional energy requirements, for example—EPA provides a "savings clause" that allows the plants to continue operating.[94] As for plants that continue operating voluntarily beyond 2028, EPA's Proposed Rule includes no savings clause, but also no penalties.[95]

The agency's approach to plants that decide not to retire after all falls short in two critical ways. First, if EPA deems such an outcome enough of a possibility to require a savings clause to protect noncompliant industry, then EPA should also account for the possibility that plants will remain in operation when considering what effects the grandfathering clause will have on health and the environment relative to the 2015 Rule. Continued operation of highly polluting plants beyond 2028, whether involuntary or not, will adversely affect human health and the environment through water pollution and through non-water quality environmental impacts. But EPA's current analysis of the Proposed Rule's health and environmental effects makes no mention of plants that remain in operation and thus fails to account for them.[96]

Second, EPA's failure to set penalties for plants that voluntarily remain in operation creates strong incentives for facility operators to claim boilers will retire and then renege at the end of 2028. If a facility operator has a plausible claim that a boiler will retire, the operator can exploit the lax standards associated with the retirement subcategory until 2028, and then withdraw from retirement and move to compliance beginning in 2029. Such plants have no reason to begin complying earlier with more costly pollution controls if the operator can get away with delaying for eight years. This loophole could considerably decrease the number of plants that comply with the Proposed Rule's overall BAT/PSES for flue gas desulfurization wastewater and bottom ash transport water. In fact, because the subcategory for retiring boilers receives such lax treatment, even boilers that qualify for EPA's other proposed lax subcategories have an incentive to opt into the retirement subcategory and then withdraw. Such perverse incentives will eviscerate the protections of EPA's already lax Proposed Rule.

Along similar lines, the grandfathering provision significantly decreases the appeal of the "voluntary incentive program," or "VIP." The VIP allows plants to delay compliance with limits for flue gas desulfurization wastewater until the end of 2028 if plants then enact stricter limitations than the default BAT/PSES. In calculating the health and environmental effects of the Proposed Rule relative to the 2015 Rule, the agency assumes that a large number of facilities will opt into the VIP.[97] According to EPA estimates, VIP participation will account for a reduction in wastewater pollutants of 105 million pounds per year.[98] But such results will come to pass only if facilities do, in fact, opt into the VIP. And the grandfathering provision makes the option significantly less attractive.

The grandfathering provision should be removed because it sets up incentives that will undermine the effectiveness of the Proposed Rule as well as the goals of the Clean Water Act.

84 Proposed Rule, 84 Fed. Reg. at 64,640–41.

85 Id. at 64,641.

86 See RICHARD L. REVESZ & JACK LIENKE, STRUGGLING FOR AIR: POWER PLANTS AND THE "WAR ON COAL" 30-35
(2016); see also Richard L. Revesz & Allison L. Westfahl Kong, Regulatory Change and
Optimal Transition Relief, 105 NW. U. L. REV. 1581 (2011); Jonathan Remy Nash & Richard L. Revesz, Grandfathering and Environmental Regulation: The Law and Economics of New Source Review, 101 NW. U. L. REV. 1677 (2007).

87 See Nash & Revesz, supra note 86, at 1708.

88 REVESZ & LIENKE, supra note 86, at 30–33.

89 Id.

90 Id. at 33.

91 Id.

92 See id. (comparing emission rates, as of 2002, of plants built before 1971 to those built during and after that year and to those built after 1978).
93 Id. at 64,666.
94 Id.
95 Proposed Rule, 84 Fed. Reg. at 64,666.
96 See generally BAC.
97 See Proposed Rule, 84 Fed. Reg. at 64,620 ("EPA also believes that participation in the voluntary incentive program would further reduce the pollutants that these steam electric facilities discharge in flue gas desulfurization wastewater by approximately 105 million pounds per year."); see also id. at 64,637 ("Under Option 2, the EPA estimated that 18 plants (27 percent of plants estimated to incur FGD compliance costs) may opt into the VIP program.").
98 Proposed Rule, 84 Fed. Reg. at 64,620.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 131

Comment Excerpt:

2. Retirement Of Units Already Scheduled To Retire Will Not Impair Reliability.

EPA's reliability case for the boilers retiring by 2028 subcategory is equally weak. EPA relies upon two premises: (1) the "time to plan, construct, and obtain necessary permits and approvals for replacement generating capacity" can take five to eight years; and (2) near-term retirement of a large percentage of the generation fleet would cause reliability issues, according to a recent NERC stress test analysis.

EPA cites no authority or evidence for its assertion that the construction of replacement capacity can take five to eight years. As an initial matter, replacement generating capacity is often not even necessary due to excessive reserve margins in most regions.[448] It is also a fallacy to suggest that one-for-one replacement of retiring generation units is needed. Most utilities rely upon a regional pool of resources for resource adequacy, and can purchase energy and capacity from other suppliers during a period in which their own generation may be less than their needs. A number of the early retirement units are in the PJM Interconnection LLC region, where resource adequacy is ensured through a number of regional wholesale market mechanisms, including a capacity market.[449] A retiring unit is immediately replaced in the region's capacity portfolio by other newly developed resources whose construction is incented by the capacity market. PJM's capacity market currently clears a reserve margin well in excess of the reliability target,[450] reflecting a surplus of low-cost capacity in the region.

Even if a plant did need to be replaced on a one-to-one basis, the time to plan, construct and obtain approvals for replacement resources takes less than five to eight years. As part of its National Energy Modeling System, the U.S. Energy Information Administration assumes lead times of one to three years for the most common new generation types.[451] Approval and installation of wind and solar facilities are particularly quick due to the reduced environmental permitting requirements for these non-emitting, non-discharging facilities. PJM's capacity market operates on a three-year forward basis, reflecting the consensus that three years is adequate lead time to develop new generation facilities.

Furthermore, EPA's reliance upon the NERC Special Reliability Assessment is misplaced.[452] NERC modeled an extreme scenario for power plant retirements, and then imposed a worst-case perfect storm event with high electricity demand and widespread electricity supply outages. As EPA acknowledges, NERC explains that "as a stress test, the scenario is not a predictive forecast."[453] Without any evidence that premature retirements associated with not carving out early retirement units would resemble the scenarios invoked in the NERC report, EPA states that NERC's "findings are consistent with the concern that electric utilities conveyed to the EPA: That the well-planned construction of new generation capacity and orderly retirement of older facilities are vital to ensuring electricity reliability."[454] Absent from this discussion is any defense of the implicit assertion that not providing an exemption for units retiring before 2028 would lead to disorderly retirement of generation units. In fact, EPA would be hard-pressed to make such a showing, because the maximum possible impact of the ELG rule is much less than what NERC modeled: EPA's data show that 6,084 MW (6.1 GW) of generation with ELG compliance needs have announced retirement or refueling dates between 2024 and 2028.[455] These units constitute the universe upon which EPA's reliability concerns must rest, since they are the only units whose retirement could otherwise be accelerated by the absence of a subcategory. By contrast, the special stress test in NERC's Special Reliability Assessment retired 118 GW of generation by 2022, which was 91 GW above the anticipated retirements that had already been announced.[456] There is simply no basis for concluding that the NERC Special Reliability Assessment stress test is relevant to the scale of retirements that could even plausibly result from the absence of a subcategory for boilers retiring by 2028.

Even if EPA had shown that a unit otherwise planning to retire in 2028 would retire in 2023 to avoid ELG compliance costs (which it has not, as described in Section X.B - Retirement Subcategory), it has not shown that this "premature" retirement would not be replaced in due course with other generation resources, as needed to ensure resource adequacy. NERC's stress test relies upon ignoring how state regulator oversight and electricity markets' inherent balancing of electricity supply and demand prevents retirements from causing reliability problems. If large quantities of generation capacity were to suddenly retire, increasing energy and capacity prices would drive investment and new entrants to the market. To pretend otherwise is to willfully ignore state planning processes and economic fundamentals. Concerns expressed by utilities that retirements accelerated by a couple of years may create reliability problems, *unsupported by any evidence of actual problems that would arise*, are inadequate to carve out a significant subset of facilities from critical Clean Water Act standards.

[448] See generally id.
[449] See PJM Interconnection, LLC, Capacity Market (RPM), https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx (last viewed Jan. 4, 2020).
[450] See, e.g., PJM Interconnection, 2021/2022 RPM Base Residual Auction Results, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx ("The 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2021/2022 Delivery Year as procured in the BRA is 21.5%, or 5.7% higher than the target reserve margin of 15.8%.").

[451] See U.S. EIA, Assumptions to the Electricity Market Module at tbl. 2 (Feb. 2019), https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.
[452] 84 Fed. Reg. at 64,640 (citing NERC, Special Reliability Assessment: Generation Retirement Scenario (Dec. 18, 2018), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf).
[453] 84 Fed. Reg. at 64,640 & n.69.
[454] Id. at 64,640
[455] See Attachment: Units in 2028 Subcategory (attached).
[456] NERC, Special Reliability Assessment, at 6.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 163

Comment Excerpt:

EPA's decision to effectively exempt[618] units either retiring or fuel switching by December 31, 2028 from compliance with the ELGs results in a significant loss of environmental benefits that should otherwise have been achieved under the 2015 ELG Rule. However, EPA did not calculate the pollution reductions that might have been achieved through pollution control upgrades at the subject facilities and therefore did not monetize the loss of such benefits within the Proposed BCA. Instead, EPA removed such facilities from consideration entirely[619] – essentially subsuming the lost benefits within an improper and artificial regulatory baseline.[620]

[618] "Under all four options, boilers retiring by December 31, 2028, would be subcategorized, and for this subcategory BAT limitations would be set equal to BPT limitations for TSS based on the use of surface impoundments." 84 Fed. Reg. at 64,630 (using substantially similar language for both the FGD wastewater and BA transport water wastestreams). See also Section X.B – Retirement Subcategory.
[619] "The EPA removed coal-fired generating units that will retire or convert fuel type prior to December 31, 2028, from the analyses supporting this proposed rule . . . ." Proposed TDD at 3-4.
[620] See 2020 Synapse BCA Analysis at 8, 11; see generally Section IV – Alternatives.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 20

Comment Excerpt:

D. APPA Supports the BAT for Units Retiring by December 31, 2028 with the Changes Discussed Below

EPA is proposing a new subcategory to include those units retiring by December 31, 2028 and setting the BAT limitations equal to BPT limitations for TSS based on surface impoundments. EPA's rationale for this new proposed subcategory is based on cost, age of equipment and facilities involved, non-water quality environmental impacts, and other factors. Since the 2015 Rule, EPA has continued to gather data regarding retirements, deactivations, and fuel conversions. EPA suggests that more flexibility is needed to avoid premature closures.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 26

Comment Excerpt:

- APPA supports the BAT for units retiring by December 21, 2028, however, EPA should expand this category to include units that will be re-powering and streamline the certification process.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 39

Comment Excerpt:

1. APPA Supports This Subcategory to Avoid Premature Retirement

EPA's data collection revealed many concerns among utilities. Many expressed alarm over the potential of stranded assets if the facility is required to install new, expensive equipment near the end of the facility's useful life. Utilities also stressed to EPA the need for sufficient time to plan, construct, and obtain permits and approvals for replacement generating capacity which is critical to support the industry's transition.

The 2015 Rule placed onerous BAT effluent limitations on units with remaining useful life. The limits in the 2015 Rule imposed unacceptable disproportionate costs on units that would be retiring in the not too distant future. Because of these costs, many units would have been prematurely retired potentially leading to electricity reliability problems.

APPA agrees with EPA's finding that establishing surface impoundments as BAT for this subcategory will help to avoid premature retirements. Factors such as low natural gas prices, compliance demands based on new environmental regulations, reduced demand, and the rise in renewable resources such as wind and solar are putting pressure on utilities forcing early retirement of assets. If a facility's expected costs will exceed the expected revenues over the remaining useful life of the facility, premature retirement may be considered.

The increased environmental regulations have sharply increased the costs leading to accelerated retirements. Retiring a coal unit will generate many additional expenses such as removal of hazardous materials, ash pond closure, closure of water intake tunnels, and more. Premature retirement also creates the problem of stranded assets, the costs of which someone must bear. Depending on the state, whether it is a regulated or deregulated state, the costs are either passed along to the ratepayer or written off as a loss by the utility. If the costs are passed along to the ratepayer this can lead to unaffordable utility bills.

Premature retirement has economic impacts on customers, utilities, and the community where the unit is located. These impacts frequently include associated job losses that accompany the retirement of a coal plant, including coal mining and power plant operations.

Other potential negative impacts from premature closures include, but are not limited to, rate impacts and negative impacts on reliability and affordability of the electricity supply. As the North American Electric Reliability Corp. (NERC) stated it is 2018 Stress Test, if retirements "happen faster than the system can respond with replacement generation . . . significant reliability problems could occur."[54] Therefore, it is important that risk-informed planning occurs to ensure continued affordability and reliability for consumers, which is why creating a subcategory for those facilities retiring by December 31, 2028, is so important.

54 Generation Retirement Scenario Special Reliability Assessment, NERC, December 18, 2018, available here: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 40

Comment Excerpt:

2. APPA Supports Expanding This Subcategory to Include Units Planning to Repower

Many facilities are now looking to repower their current systems for a variety of reasons. This could be to improve generation economics, extend the life of the plant, or to reduce emissions to comply with state clean energy laws, just to name a few. EPA noted in this Proposed Rule that at least five facilities that had announced retirement dates had those dates involuntarily delayed due to either an order issued by the U.S. Department of Energy under Section 202(c) of the Federal Power Act or a state public utility commission reliability must-run agreement. For those facilities planning to repower by December 31, 2028, EPA should create a subcategory so that those facilities do not have to bear the costs of installing expensive equipment to comply with the Proposed Rule for such a short period of time.

The environmental benefits related to eliminating BA transport water and FGD wastewater are realized if a permittee decommissions a coal unit or repowers. EPA's own Supplemental Technical Development Document suggests "[that] EPA determined the baseline and post-compliance *pollutant loadings are equal to zero for units that announced plans to retire, convert to a non-coal fuel source*, or change/upgrade ash handling practices by the time the … units are required to meet the requirements of the proposed rule."[55] In our view, there is no environmental basis to distinguish between retiring a unit and those being repowered.

Further, repowering decisions are often made in concurrence with retirement decisions. Repowering units on the same site as a former coal-fired unit is a way for a community to redevelop the site, given there is existing infrastructure which can be reused.

55 Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental TDD), Document No. EPA-821-R19-009 (U.S. EPA, 2019a) at 6-3, n.39.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 41

Comment Excerpt:

3. Including Units that Repower in the Retirement Subcategory Facilitates the Industry's Transition

The retirement subcategory is an important element of the Proposed Rule. The retirement subcategory provides the necessary time for industry to transition in light of the ELG and CCR rules. The retirement subcategory was designed to "ensure that facilities could make better use of the CCR rule's alternative closure provisions, by which unlined surface impoundments could continue to receive waste and complete closure by 2028."[56] While facilities may have ceased receipt of waste before that date, a 2028 date ensures that the ELG will not limit the use of the alternative closure provision regardless of when a facility ultimately ceases receipt of CCR. [57]

Under certain circumstances, the CCR rule's alternative closure provisions allow units otherwise required to close to continue receiving CCR. There is nothing in the CCR rule preventing a facility from using the alternative closure provisions for boilers that are repowering with a non-coal fuel source.

56 84 Fed. Reg. at 64,641.
57 Id.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 42

Comment Excerpt:

4. APPA Suggests Streamlining the Certification Process and Amending the Date for the Certification Statement

As part of the proposed subcategory for those boilers retiring by December 31, 2028, EPA is proposing a reporting and recordkeeping requirement which mandates that, as part of any permit renewal or re-opening when facilities are making the request to be included in this subcategory, the facility must submit a one-time certification stating the date of the expected retirement from the combustion of coal, and provide a citation to any filing, integrated resource plan, or other documentation in support of that date. This initial certificate statement must be submitted by the "as soon as possible" date which in this Proposed Rule would be November 1, 2020.

APPA suggests that EPA streamline this certification process and allow units to certify on or before December 31, 2023. Setting a three-year timeframe for electing retirement/repowering will simplify the timeframe for electing retirement/repowering, will simplify the timing requirement, and increase regulatory certainty.

Otherwise, under the proposed timing requirement, permittees would have to submit their retirement/repowering certification with their permit applications, disadvantaging certain facilities. If a permit renewal is due shortly after the effective date of the rule, the permittee may not have enough time to analyze the final rules' impact. However, in circumstances where a final permit with applicability dates for FGD wastewater and BA transport water retrofits that is less than three year after the effective date of the final rule, APPA would recommend permittees be allowed to certify repowering or retirement of the units any time prior to the earliest applicability date in the permit.

9b <u>Subcategorization – Low Utilization</u>

Commenter Name: Kevin C. O'Brien
Commenter Affiliation: Prairie Research Institute, Illinois Sustainable Technology Center
Document Control Number: EPA-HQ-OW-2009-0819-8288-A1
Comment Excerpt Number: 1

Comment Excerpt:

As the Principal Investigator on the U.S. Department of Energy-funded large pilot research on next-generation carbon capture (CC) technology (DE-FOA-0001788), I wish to inform you of unintended consequences arising from the 2019 Proposed Revisions to the Steam Effluent Guidelines and their impacts on City Water, Light, and Power in Springfield, IL.

Successful scaling up of low-cost carbon capture at CWLP will have global implications in cutting CO_2 emissions from fossil fuel energy. The engineering design is underway now (2019-2020) at the site, to be followed (2021-2025) by the construction and operation of the CC pilot plant.

As a new facility (10 years) CWLP's Dallman 4 Unit is already among the most modern generating facilities in the nation. As CWLP weighs its options for the economical generation of electricity, the flue gas desulfurization (FGD) wastewater treatment requirements under the proposed revisions are likely to impact the success of our research. <u>We respectfully urge you to consider these points when reviewing CWLP's request to adjust the low utilization limit to 1.3 million MWh.</u>

If the new rule passes as written today, the two possible classifications for CWLP (shown below) will jeopardize the project.

- The requirement of biological treatment would threaten the economic viability of CWLP's Dallman 4 Unit, as well as disrupt our ongoing testing through shutdown or treatment facility construction.
- Classified as a low utilization boiler facility (876,000 MWh per year or less), Dallman 4's benefit-cost ratio might well favor closure. Also, the altered flue gas parameters under low utilization might render the pilot technology testing regime moot.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 62

Comment Excerpt:

9. **LOW-UTILIZATION UNIT EXEMPTION**

EPRI reviewed EPA's evaluation of the low capacity utilization category threshold, which is shown in the ELG's Figure VIII-1 (Costs per MWh Produced vs. MWh Produced) [EPA, 2019]. EPRI generated similar curves based on EPA's list of plants along with EPRI's compliance cost estimates. EPRI cost estimates for FGD BAT and BATW, as described in our comments in Sections 2 and 8.4, are higher than EPA's.

To evaluate how changes in operating conditions across years would relate to this threshold, we evaluated both 2017 net generation rates (Figure 9-1) and 2018 net generation rates (Figure 9-2). The results appear to be similar, with nearly the same number of units below the threshold in the two years evaluated (55 in 2017 versus 56 in 2018). Both EPA and EPRI estimated costs are exponentially higher at units that are under EPA's current threshold of 876,000 MW-hr per year compared to units above this threshold.

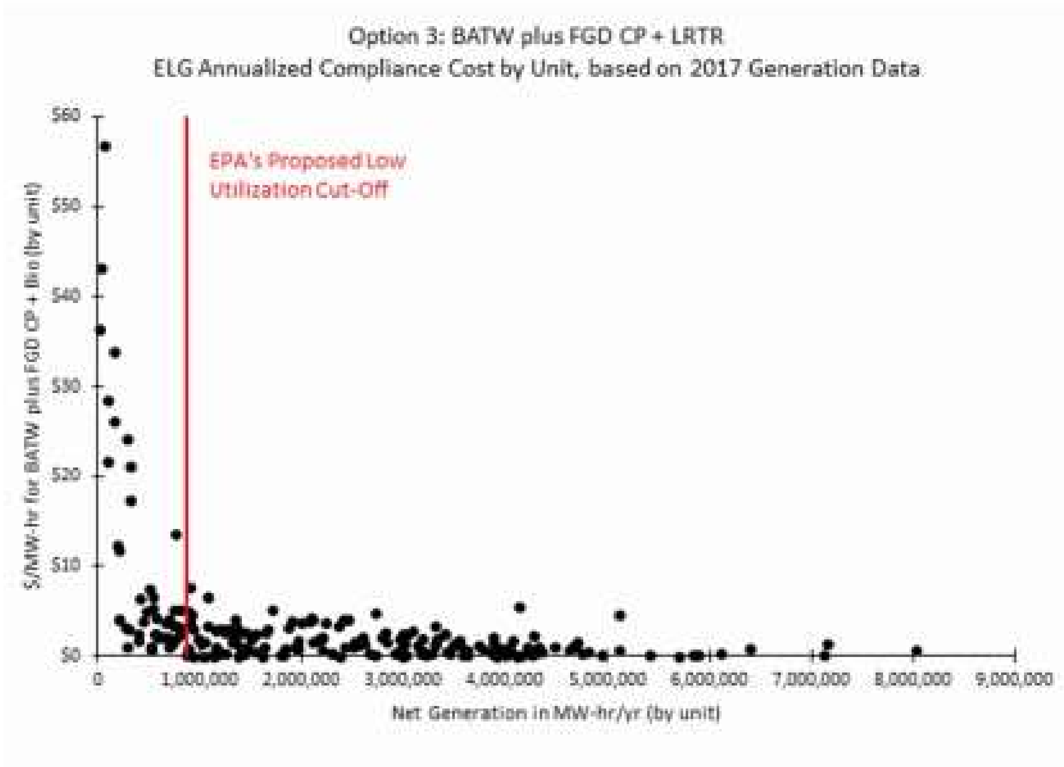

Figure 9-1
EPRI's calculated cost per net generation at each unit based on 2017 generation

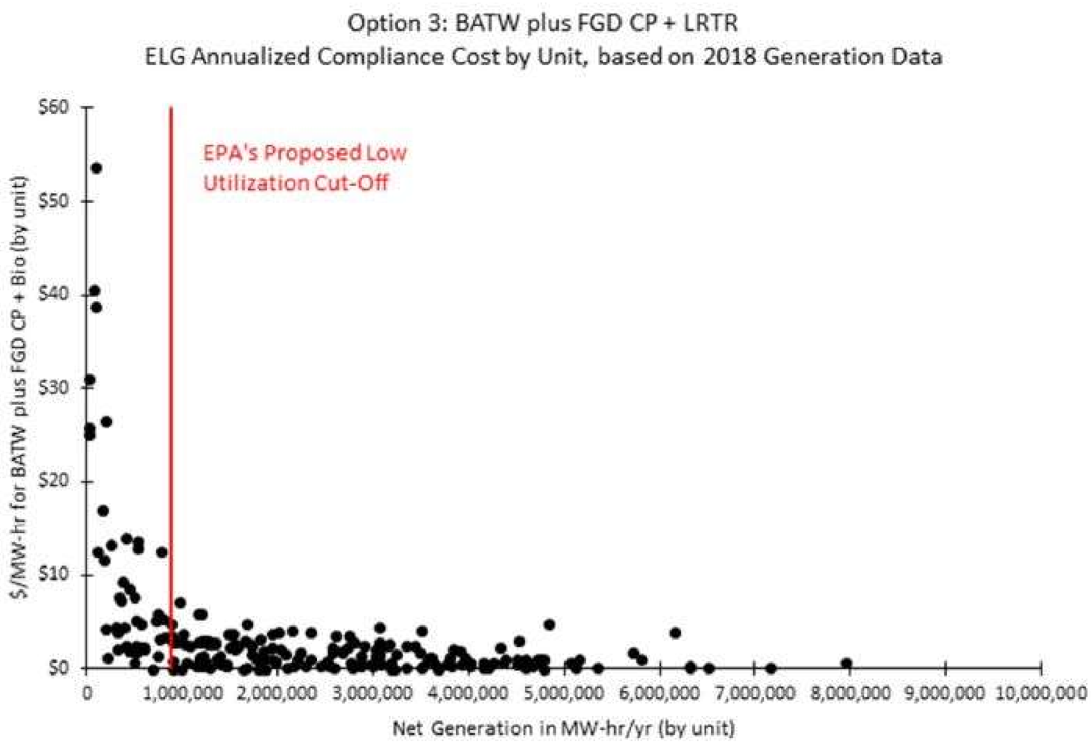

Figure 9-2
EPRI's calculated cost per net generation at each unit based on 2018 generation

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 24

Comment Excerpt:

VI. The Proposed Rule's Subcategory For Low-Utilization Boilers Should Be Further Developed.

EPA proposes to establish a subcategory for "low-utilization units" producing less than 876,000 megawatt hours (MWh) per year—the equivalent of a 100 MW boiler running at 100 percent capacity or a 400 MW boiler running at 25 percent capacity. 84 Fed. Reg. at 64,638-9. The EPA solicits comment on whether this subcategory should be based on alternative utilization thresholds. For this subcategory, the EPA proposes to select chemical precipitation as the technology basis for BAT for FGD wastewater, with effluent limitations for mercury and arsenic. EPA proposes to establish this subcategory based largely on changes in the industry and overall cost impacts in terms of cost per MWh of power produced that the Proposed ELG rule would require of units that are less utilized and "exacerbate" existing cost disparities between units in the industry. EPA states that such a subcategory would be useful for ensuring electric reliability "in the near term." Id. EPA also cites the Fifth Circuit's decision in *Southwestern Electric Power Company (SWEPCO) v. EPA*, which found EPA's use of surface impoundments as the technology basis for effluent limitations on legacy wastewater to be arbitrary and capricious since it did not sufficiently identify statutory factors in its analysis, and EPA notes that the Court left open the possibility that surface impoundments could be used as the basis for BAT effluent limitations so long as the Agency identifies a statutory factor, such as cost, in its rationale for selecting surface impoundments. *SWEPCO v. EPA*, 920 F.3d (5th Cir. 2019).

In light of the decision in *SWEPCO*, the Agency should ensure it has a robust analysis and a well-explained rationale before it finalizes the proposed subcategory. EPA must pay particular attention to developing the record with respect to its two possible justifications: disproportionate costs and non-water quality environmental impacts, including energy requirements. EPA should also determine and substantiate whether the "age of the equipment and facilities involved" is directly relevant to the creation of this subcategory. 33 U.S.C. § 1314(b)(2)(B). In general, though not always, older and less efficient facilities tend to be less utilized.

Low-utilization boilers can play an essential role in the operation of the electric system, especially for system emergency situations. EEI and its member companies have focused significantly on improving the resiliency of both the electric grid and the generating fleet as part of the clean energy transformation. Our industry is leading a profound transformation to deliver the energy future that customers want by investing in smarter energy infrastructure that empowers customers, ensures reliability, and reinforces resiliency. The energy grid is a platform with unique resilience qualities, and electric companies have decades of experience and responsibility building, owning, operating, protecting, and restoring the grid, while serving as critical infrastructure providers, national security partners, and first responders.

Developing a resilient energy grid requires a flexible set of tools that electric companies need to leverage depending on geography, risk profile, and other factors. Low-utilization boilers can provide that flexibility and serve a critical function in the industry's commitment to grid resilience across a wide array of situations. However, EPA should consider further refinement of its proposal for this subcategory to better promote the goal of resiliency and to fully align its rationale with the overall regulatory structure. Instead of the proposed utilization metric based on a flat number of MWh per year, EPA could look to its past practices in other rules for how to define potential subcategories that can be easily implemented by electric companies in a limited manner that could support the industry's commitment to grid resilience.

For example, the 2012 Mercury and Air Toxics Standards (MATS) recognized the critical nature of certain units—especially those that may need to operate in emergent situations. EEI advocated that EPA allow for tailored subcategories to recognize the need for some units to operate in fuel disruption events—especially during hurricane and storm recovery events. In response to these concerns, EPA created a "limited-use liquid oil-fired" MATS subcategory that units could qualify for if (1) the unit was a "oil-fired electric utility steam generating unit" and "fossil fuel-fired;" and (2) had an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24- month block contiguous period commencing. *National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule 77 Fed. Reg*. 9,370 (Feb. 16, 2012). This allowed for discreet operational periods in a way that was both environmentally protective in terms of aggregate emissions but allowed for on-time operations of the units during specific grid emergency events—like hurricane landfalls—through the use of a combination of capacity factor and averaging periods. While not directly applicable to this rulemaking, this tailored and limited approach is easily understood, narrowed to specific limited operational hours and conditions, and implementable by electric companies given that the averaging provisions are easily calculated and predictable in the event they are ever needed.

Alternatively, the Agency could draw on the approach utilized by the CAA's permitting program. The CAA makes a distinction between "major" and "minor" stationary sources based on the potential to emit (PTE) air pollutants by those sources. Within the "minor" source permitting world, there are two different types of permit classifications: "True minor sources" and "synthetic minor sources." True minor sources are sources that emit, or have the PTE, regulated New Source Review (NSR) pollutants in amounts that are less than the major source thresholds under the Prevention of Significant Deterioration (PSD) program, but equal to or greater than the applicable minor NSR thresholds. However, and more relevant to the ELG subcategory context, synthetic minor sources have the PTE regulated NSR pollutants in amounts that are at or above the thresholds for major sources, but have taken a restriction so that their PTE is *less than* the threshold amounts for major sources.[22] One approach for subcategorization could be to employ a similar framework through the establishment of enforceable utilization or discharge thresholds in permits. Such an approach could address the economic and technological challenges presented by low-utilization units when considering installation of extensive pollution control technology while also ensuring both environmental progress and the availability of these resources for specific resiliency needs.

Such an approach allows EPA to rely on multiple statutory factors such as cost, non-water impacts and engineering based technological considerations for justification of the subcategory. A subcategory that utilized these criteria might be able to produce equivalent environmental results while providing needed operational flexibility for certain units. Given that MWhs produced are often the result of system needs and not necessarily as predictable on a year to year basis without such effective limitations, such an approach might be workable for the Agency and for operators.

EPA should consider developing or allowing one of these alternative approaches in its final rule. Whichever approach the Agency chooses to develop, EPA must ensure that its chosen criteria are sufficiently supported in the record, easily understandable, and able to pass muster under *SWEPCO*.

[22] Such restrictions must be enforceable as a practical matter Pursuant to 40 C.F.R. § 49.152

Commenter Name: Major L. Clark, III and David Rostker
Commenter Affiliation: Office of Advocacy, U. S. Small Business Administration
Document Control Number: EPA-HQ-OW-2009-0819-8310-A1
Comment Excerpt Number: 2

Comment Excerpt:

In particular, EPA should be closely examining the TWPE metric for the following requirements.

- **Low-Utilization Thresholds:** For at least three units operated by small entities that exceed a net generation of 876,000 MWh, the proposed controls for bottom ash wastewater exceed $10,000/TWPE. APPA recommends a higher threshold of 1,314,000 MWh. Advocacy recommends that EPA also consider a threshold of 1,710,000 to provide additional relief to small entities.

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 1

Comment Excerpt:

As a general matter, EPA has set overly stringent discharge limitations for metals and other wastewater constituents that cannot be reliably achieved by the "best available" control technologies selected by EPA itself in the ELG rulemaking. To correct this problem, Santee Cooper supports EPA's proposal to establish new source subcategories for EGU boilers that have low-utilization levels or will retire by December 31, 2028. The adoption of these proposed new source subcategories is necessary to avoid the imposition of excessive compliance costs and address unique operating conditions of affected EGU sources.

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 2

Comment Excerpt:

One important focus of Santee Cooper's comments below is to provide suggested technical measures that EPA should consider adopting to improve the workability of the proposed subcategories. For example, we urge EPA to establish a multi-unit averaging procedure for meeting the annual net generation limitation for being classified as a low-utilization unit. As discussed below, allowing multi-unit averaging for low-utilization units will lower operational costs and promote electric grid reliability. Furthermore, it will achieve these important policy objectives while also ensuring the protection of the environment given that the total amount of cumulative effluent discharges from the entire facility under the combined generation limitation are equivalent to the amount of discharges under a unit-by-unit approach.

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 5

Comment Excerpt:

A. Multi-Unit Averaging For Low Utilization Boilers Should Be Provided To Lower Operational Costs And Promote Electric Grid Reliability.

EPA proposes to establish a new source subcategory for low utilization boilers. A low utilization boiler is defined in the Proposed Rule as a boiler with a two-year average annual net generation that is below 876,000 MWh per year (equivalent to a 400 MW coal-fired boiler operating at a 25% capacity factor).[3] The establishment of this subcategory makes sense given that many existing coal-fired EGUs were operated at one time as baseload generating facilities, but are now dispatched as load-following units or even just operate for short durations to meet peak demands in the summer or winter. Furthermore, we agree with EPA's proposal to use a two-year average when setting the annual generation limitation of 876,000 MWh per year. The use of a two-year average will help to smooth out any sudden unplanned increases in a unit's annual generation levels due to unforeseen circumstances, such as extreme weather events or forced outages of other generating units with an electricity utility system. To provide further operational flexibility, Santee Cooper recommends that EPA not impose the annual net generation limitation only on a boiler-by-boiler basis. Rather, the Agency should allow an EGU owner or operator to comply with the annual generation limitation by averaging the annual generation production levels of multiple EGUs. In particular, such averaging should be allowed among affected generating units under common operation or ownership that are located at the same EGU facility site. If, for example, three units are located at one generating facility, the owner or operator of those units would have the option of electing to comply either with the proposed annual generation limitation of 876,000 MWh on a unit-by-unit basis, or a combined generation limitation of 2,628,000 MWh (3 x 876,000 MWh) that would apply to all three units through the multi-unit averaging compliance option. The added flexibility provided through averaging among multiple affected units will lower operational costs and promote reliability of the electricity grid, while still ensuring the protection of the environment. It lowers operational costs by providing increased operational flexibility. For example, the multi-unit averaging compliance option allows EGU owners and operators to dispatch lower-cost units at higher utilization levels than the higher-cost units over the annual compliance period so long as the combined annual generation limitation is achieved for all units at the facility. Similarly, this operational flexibility will help to ensure electric grid reliability by allowing one unit to operate higher than its annual unit-specific generation limitation of 876,000 MWh if one of the other units at the same facility is unable to operate due to an extended forced outage or other operational constraint. Finally, such an averaging provision will provide these important operational and reliability benefits while still ensuring the protection of the environment given the total amount of cumulative effluent discharges from the entire facility under the combined generation limitation are equivalent to the amount of discharges under a unit-by-unit approach.

[3] Santee Cooper also would support a higher threshold as recommended by APPA.

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 6

Comment Excerpt:

Finally, Santee Cooper has a technical concern regarding the process proposed for electing to apply the annual generation limitation under the low-utilization subcategory. The Proposed Rule requires the owner or operator to submit an initial certification statement that provides the calculation of the two-year average net generation limitation for each applicable boiler, along with the required underlying information in support for that calculation. This submission requirement, however, is unclear and needs clarification with respect to the timing and process for making the submission. In particular, the regulatory text in the Proposed Rule only states that "an initial certification shall be made to the permitting authority with a permit application."[4] It does not specify any minimum date by when the submission must be made. Nor does it address those situations (which will frequently occur) when permit applications are currently pending or the permitting authority has recently issued a National Pollutant Discharge Elimination System ("NPDES") permit for the boiler and the submission of a new permit application may not be necessary for another four or five years. To clarify submission requirements for these situations, Santee Cooper recommends that EPA revise proposed section 423.19(e)(1) to require that the initial certification statement be submitted to the permitting authority by a date certain, specifically within three years from the promulgation date of the final ELG rule in the Federal Register. In addition, EPA should add language to the final rule indicating that low-utilization boiler certification can be made on the basis of the utility's expectations for its' future operation, even if the boiler had not operated as a low-utilization boiler prior to publication of the rule. We also recommend the addition of an "off-ramp" for facilities which may need to operate at a higher rate of production than anticipated. We recommend such facilities be given one year to agree to a compliance schedule with their regulator and up to five years to construct and begin operating the new wastewater treatment technology.

[4] 84 Fed. Reg. at 64,677 (citing proposed 40 C.F.R. §423.19(e)(1)).

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 9

Comment Excerpt:

C. Disproportionately High Compliance Costs Would Be Imposed on Low Utilization and Retiring Units Currently,

Santee Cooper operates two coal-fired steam electric generating facilities. A review of current operation levels for each of these facilities demonstrates the clear need for changes to both the 2015 ELG rule and the Proposed Rule. These changes are necessary to reflect the fact that both the actual and future forecasted operation levels of these facilities have declined significantly and, consequently, will result in very substantial increases in wastewater treatment costs in the absence of effective subcategorization. As we have noted already, the Proposed Rule is a dramatic improvement given its use of subcategorization for low-utilization and retiring units. However, as discussed below, further subcategorization (as discussed below) is needed in order better align the ELG control requirements with the current state of the electric power sector. Santee Cooper's Cross Generating Station is a 2370-MW facility with a current net annual capacity factor of about 45%. Forecasts indicate that the Cross facility will likely maintain a capacity factor of 40-50% through 2030, after which we expect its capacity factor to decline to 30-40% through 2039. This is down from the facility's net annual capacity factor of about 80% in 2007, or a more than 40% reduction in capacity factor to date, and thus, a corresponding decline in FGD wastewater discharge. Therefore, the Cross Generating Station has already achieved a 40% reduction in discharge of ELG pollutants to the benefit of the environment. A similar trend exists for our Winyah Generating Station, which is located along the coast near the far-eastern edge of our service area and has a capacity of 1130 MW. From 2016 to 2018, the Winyah facility operated with a less than 25% net capacity factor. Santee Cooper has recently announced preliminary plans to retire the four coal-fired units at this facility. The target retirement dates are 2023 for Winyah Units 3 and 4, and 2027 for Winyah Units 1 and 2. The actual retirement dates are uncertain and will depend on a number of important factors beyond the full control of Santee Cooper at this time, including the amount of time it will take for Santee Cooper to construct and bring online sufficient replacement generating capacity. Current forecasts project that the entire Winyah Generating Station will operate at about a 6-7% annual capacity factor in 2020-2022, with Winyah Units 1 and 2 operating together at about an 8-15% capacity factor until they are closed in 2027. These generation levels are down from a capacity factor of about 75% for these two units in 2007, indicating about an 80% reduction in capacity factor with a corresponding reduction in FGD wastewater discharge to date. Again, these reductions in the volume of effluent discharges have been achieved at minimal cost to our ratepayers, and Santee Cooper will eliminate the discharge altogether in the near future. EPA's unit level analysis predicts that the Winyah Generating Stations will choose to operate as a low capacity boiler by installing chemical precipitation. Santee Cooper's actual preference would be to close the Winyah facility within a 7-12 year planning horizon (depending on the actual time that Santee Cooper will need to develop a replacement facility in the region). Unfortunately, the Proposed Rule will make it more difficult to transition to new and cleaner replacement generation capacity given that EPA's proposed effluent discharge limitation for FGD wastewater could require Santee Cooper to invest many millions of dollars in the facility for just a few years before retirement (which was incorrectly estimated as zero capital dollars in EPA's unit analysis). The adoption of the additional source subcategorizations outlined below are therefore critically important to minimize this risk of forcing the power sector to incur major capital costs for constructing wastewater treatment facilities that have a very limited useful life due to future plant retirement schedules. As part of Santee Cooper's efforts to implement the 2015 rule, we estimated that costs to remove selenium from the FGD wastewater at the Winyah Generating Station. Those estimates indicated that the selenium removal costs with a high residence time biological treatment system were on the order of $12,000-$14,000 per pound (2016 dollars), assuming a 30-year lifespan and 100% capacity factor. Based on our new generation forecasts for the four Winyah units, the same analysis technique indicated costs to remove selenium through biological treatment at would be on the order of $60,000-$160,000 per pound (2016 dollars). Using the same analysis technique, we found that biological treatment costs at the Cross Generating Station increased from $12,000- $14,000 per pound (2016 dollars) to $17,000-$20,000 per pound (2016 dollars) given lower forecast capacity factors. This stands in sharp contrast to the significant reductions Santee Cooper has achieved at low cost since 2007, and which stand to be further reduced when the Winyah facility closes. EPA could facilitate this process with a longer retirement exemption of some kind, given the difficulties Santee Cooper will face in developing replacement power in an area that is underserved by natural gas pipelines and therefore currently has inadequate natural gas supply to meet the future demand of a new natural gas generating replacement facility. Although the EPA's evaluation of Santee Cooper's coal-fired generating facilities predicted that the Santee Cooper would use membrane treatment at the Cross facility, Santee Cooper has not evaluated that technology and did not contribute any site-specific information or analyses to EPA's evaluation. EPA also estimated high residence time reactor annual costs for Cross as a baseline scenario, with annual O&M costs on the order of $122,000-$591,000 per unit per year (2018 dollars). Our cost analysis of high residence time systems yielded much higher estimated annual operating costs on the order of $800,000-$960,000 per unit per year (2016 dollars). While we did not receive a bid from a low residence time vendor previously, these numbers call into question whether EPA's cost estimates are realistic for these types of systems as well. This is based on the following experiences: (1) in our efforts to comply with the 2015 rule prior to its postponement, vendors were unable or unwilling to provide suitable performance guarantees at the levels EPA had established; (2) our experience installing submerged flight conveyors and remote submerged flight conveyors previously demonstrated that actual capital costs are often dramatically more than estimated, especially given aggressive scheduling (which constrains vendors and their suppliers, consultants, etc.); (3) During trials of the advanced treatment technology, none of the vendors were able to demonstrate their technologies could reliably meet the thresholds for both mercury and selenium, which was before EPA lowered the regulatory limit for mercury (to that end, we support UWAG's request that mercury and selenium limits be adjusted).

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation

Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 12

Comment Excerpt:

Low Utilization Boiler Subcategory
FirstEnergy supports the low utilization boiler ("LUB") subcategory to allow limited use operation of certain pieces of equipment to provide significant resiliency to the power grid. As examples by UWAG have highlighted, the power grid remains vulnerable to weather or other events (i.e. unexpected outages) that occur during periods of high-power demand (i.e. summer and winter). As such, LUB units can provide critical power during these periods to ensure our customers continue to receive power. FirstEnergy does have concerns that the Proposed Rule disincentivizes maintaining LUB units in three ways, the initial certification process, the initial demonstration process, and winter weather preparedness.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 13

Comment Excerpt:

LUB Certification
The Proposed ELG Rule's initial LUB certification is, at best, confusing, and, at worst, significantly limiting to the permittee. By setting the time period sometime between the permit application or as soon as possible but no later than the applicability date, there is significant ambiguity in the date that the permittee must notify the respective agency. Also, permittees, like FirstEnergy, have permits that are currently in the process of being renewed which was never clarified in the Proposed Rule. This uncertainty could lead to an initial certification date of November 1, 2020.

FirstEnergy proposes that the initial certification be two years after the effective date of the rule. The timing allows permittees to make a determination on appropriate capital expenditure requirements of the various options and subcategories along with conducting an alternatives analysis to determine the most appropriate action for our customers.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 14

Comment Excerpt:

LUB Limit

FirstEnergy has concerns that the initial LUB certification needs to prove that the permittee has *already* [emphasis added] demonstrated that the unit is meeting 876,000 net megawatt hours ("MWh") per year. Market dynamics are rapidly changing, and the utilization of existing coal facilities is declining. According to Energy Information Administration data, coal electricity generation has decreased from 1,755,904,000 MWh in 2009 to 1,145,962,000 MWh in 2018, a drop of 53 percent in less than a decade.[2] The trend is likely to continue due to a variety of factors including, but not limited to, economics, financing, age, and environmental requirements. As such, a permittee may have to prove their LUB status now, to be able to make the initial certification period. This process does not consider that past market practices may no longer be indictive of future business conditions. Instead, the LUB status should focus on the future, as the Proposed Rule's benefit and costs analysis has demonstrated. The LUB status should be applicable and legally binding when the permittee makes the initial certification and not need demonstrated prior to making the initial certification.

2 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 15

Comment Excerpt:

LUB Winter Weather Preparedness

As stated above, LUB units provide critical grid reliability and resiliency efforts during weather and other extreme events. By their definition, LUB units do not operate for long periods of time. In winter, LUB units may be off for most, if not all, of the season, depending on grid dynamics. However, freezing temperatures coupled with no units running can cause freezing to major pieces of critical plant equipment which can affect to overall operability of the unit. FirstEnergy recommends that during these periods the units be allowed to start, under minimal load, and certify that the unit was operated to provide plant heat without counting towards the facility's 876,000 net MWh limit.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 14

Comment Excerpt:

Finally, UWAG applauds EPA's proposed low utilization subcategory and focused its efforts on evaluating the proposed limits and technologies and whether those are appropriate for units that are likely to qualify for this subcategory and which provide critical power during peak demand times. UWAG recommends that EPA make some amendments to the proposed best management practices approach for BATW and consider including automated process systems for BATW recycling.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 15

Comment Excerpt:

UWAG also suggests that EPA consider a tiered approach to the subcategory. In the first tier, units certifying to remain at or below 438,000 MWhs (a level consistent with a 50 MW unit operating at full capacity) based on a forward-looking, two-year average net generation would be subject to TSS limits equivalent to best practicable technology ("BPT") and would not have to meet the proposed mercury and arsenic limits for FGD wastewater or take any further action for BATW. In the second tier, units that would certify to both (1) remain under 876,000 MWhs based on a forward-looking, two-year average net generation, and (2) retire by December 31, 2031, would also be subject to TSS limits equivalent to BPT. These units would not be required to meet the proposed mercury and arsenic limits for FGD wastewater or take any further action for BATW. In the third tier, any unit certifying that it will remain under the 876,000 MWhs threshold, but not retiring would meet the mercury and arsenic limits for FGD wastewater and would be subject to a BATW best management practices plan. UWAG offers this approach for EPA's consideration.

Commenter Name: Mike Krumland
Commenter Affiliation: Nebraska Public Power District (NPPD)
Document Control Number: EPA-HQ-OW-2009-0819-8308-A1
Comment Excerpt Number: 3

Comment Excerpt:

NPPD generally supports BAT for the Low Utilization Boiler subcategory; however there are few things that would make it more workable for the regulated community.

The permittee should only be required to certify that they intend to operate at the low utilization boiler threshold to qualify for inclusion in this subcategory. The preamble appears to require the unit(s) to operate for two years in the low utilization subcategory before they are eligible for inclusion in this subcategory.

Commenter Name: Michael P. Alaimo
Commenter Affiliation: Clean Fuels Michigan, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8305-A1
Comment Excerpt Number: 6

Comment Excerpt:

Proposed sub-categories to allow weaker limits for some plants are unjustified: EPA is also proposing new loopholes that will allow certain power plants to discharge even more pollution into our nation's waters. For example, if a plant operator claims a plant will retire by 2028, that plant would be completely exempt from these newer pollution limits. In Michigan, a state where many of our coal plants won't retire until 2028, this puts our water bodies at undue risk. According to data compiled by Michigan Environmental Council from the EPA's Toxic Release Inventory, coal plants in Michigan discharged 48,697 pounds of toxic pollutants into water bodies in 2016 alone. This loophole would allow plants to unjustifiably continue to contaminate rivers, lakes, and streams in Michigan and across the country for five more years. EPA's proposal would also exempt plants that claim to only operate for a limited number of hours per year. EPA must abandon these loopholes that put utility profits above public health and the environment.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 3

Comment Excerpt:

The 2019 Proposed Rule includes a number of subcategories that could benefit economically stressed facilities like GenOn's stations in Maryland. However, the facilities will not be able to take advantage of the subcategories if the 2015 ELG date is not changed. For example, most, if not all, of GenOn's boilers in Maryland will meet the net generation requirements of the low-utilization boiler ("LUB") subcategory. However, if the date remains at November 1, 2020, GenOn's facilities will not be able to utilize the LUB subcategory because they would have already procured and installed the technology required under the 2015 ELG Rule.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 7

Comment Excerpt:

GenOn agrees that "[m]arket conditions in the electricity generation sector have changed significantly and rapidly in the past decade due to (1) the lower cost of natural gas; (2) technological advances in solar and wind power; and (3) the continued aging of coal-fired facilities. 84 Fed. Reg. 64626. As a result, GenOn strongly supports the overall inclusion of the LUB subcategory for both FGD wastewater and bottom ash transport water in the 2019 Proposed Rule and ultimately in any resulting final rule. GenOn would also like to highlight the following specifics of the LUB subcategory that it strongly supports.

- GenOn approves of the use of a two-year average for calculating applicability of the subcategory. Such an average, will better ensure that LUBs responding to a single extreme demand event in one year can still qualify for the subcategory.
- GenOn agrees with the use of the EIA reports because it would eliminate unnecessary paperwork.
- GenOn agrees with EPA's proposed "savings clause" that would protect a facility that involuntarily fails to qualify for the subcategory.
- GenOn supports the proposed BMP provisions that would "require applicable facilities to develop a plan to minimize the discharge of pollutants by recycling as much BA transport water as practicable back to the BA handling system." Id. at 64664.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 8

Comment Excerpt:

- GenOn proposes that in cases where FGD wastewater from multiple affected boilers/units is treated through one wastewater treatment plant that the calculation of net generation allow for the averaging of the multiple units. This would allow peaking boilers with decreasing utilization to avoid disparate costs when compared to other combined units greater than the net generation requirement. For example, at a station with two units/boilers, major outages (planned or unplanned) can shift generation between the two units. Taking a two-year average of each boiler may not account for major outages that occur every three to five years. Averaging the two boilers/units would better represent the operations. This was the case at GenOn's Morgantown Station in 2019. Morgantown Unis 1 & 2 share a wastewater treatment plant. In 2019, Unit 1 had a long outage, but averaged together Unit 1 & 2 meet the LUB subcategory threshold.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)

Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 9

Comment Excerpt:

- GenOn proposes that, to initially qualify for the subcategory through a permit renewal or reopening, facilities submit calculations of the two-year average net generation that excludes net generation associated with "ISO mandated" or "must run" obligations. Must-Run Generation is defined by PJM as "Generation designated to operate at a specific level and not available for economical dispatch. Also referred to as fixed generation." In wholesale markets where the most economic resources are expected to operate in a logical cost-based hierarchy, the ISO may require operation of specific units to meet distribution constraints. These events are normally short in duration but may last months and cause an abnormally high capacity factor. LUB units must be able to exclude these involuntary runs from calculation of normal net generation.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 10

Comment Excerpt:

- GenOn proposes that the categorization of LUBs be less than or equal to 25% unit net capacity factor. GenOn's Morgantown Station in Maryland has two boilers rated at 645 gross max capacity and the capacity factor in 2019 was 10.98% and 20.78% respectively. These are now peaking units. At one time, these units were base loaded units and had capacity factors in the 70-90% range. Under the proposed rule, the Morgantown units may not be eligible for the LUB subcategory.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 11

Comment Excerpt:

- Instead of requiring LUB facilities with bottom ash transport water to submit a facility specific plan as part of any permit renewal or re-opening, 84 Fed. Reg. 64667, GenOn proposes that EPA require the inclusion in the NPDES permit of a milestone schedule for the submittal of a facility-specific plan, agency approval, and implementation on the effective date of the permit condition instead of at the time of permit renewal or reopening. Requiring the submittal of a facility-specific plan with the application for renewal or re-opening will delay the issuance of the permits being re-opened.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 12

Comment Excerpt:

Finally, GenOn requests clarification regarding the subcategory. EPA proposes the two year timeframe for the tier limits to begin. This could start when the net generation information is submitted to EIA or January 1 of the year following exceedance. The annual EIA 923 is due within 45 days after the online form opens for annual collection, which is often on the first business day of January following the reporting year. For example, assuming the online form is available January 4th, the EIA 923 reporting would be due by February 18th at the latest and net generation information would be due by April 18 at the latest. GenOn requests that EPA specify that the clock starts on January 1 of the year following loss of LUB eligibility.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 7

Comment Excerpt:

TVA welcomes the establishment of a subcategory for low utilization boilers and high flow FGD systems and application of the 2015 limits for mercury specifically for these systems. TVA believes that the factors EPA cited including disproportionate costs are an appropriate basis for establishing these subcategories.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 24

Comment Excerpt:

The BMP plan for low utilization boilers in 423.13(k)(3)(iv)(B) should not require daily inspections; rather the inspection frequency should be set by the professional engineer developing the plan based on judgements about risk and consequences.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 28

Comment Excerpt:

EPA should reconcile the difference in language regarding what constitutes a "low utilization boiler" present in 423.11(z) which is stated as a "two-year average annual net generation is below 876,000 MWh per year" and in 423.13(g)(iii)(B) which is stated as a "two year average net generation of such boiler is below 876,000 MWh per year." TVA believes the former is correct.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 19

Comment Excerpt:

USEPA has recognized in many aspects of this supporting documentation of the rule that the costs of compliance with the BAT /PSES limits for FGD wastewater and BA transport water are cost prohibitive for small sources. While CWLP exceeds the cutoffs established for smaller sources, it does so by a relatively small degree and thus will likely be one of the most disproportionately impacted facilities in the country by these rules.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 26

Comment Excerpt:

Low Utilization Category Adjustment

CWLP is generally supportive of the proposed subcategory for boilers with low utilization as it applies to our older Units 31, 32 and 33 even though it would not provide relief to Unit 4. CWLP agrees that due to changes in utilization, reliance on nameplate capacity alone is problematic and electricity production should be considered. EPA is proposing to establish a subcategory for low utilization units producing less than 876,000 MWh per year. EPA's rationale is that disparate costs to meet the proposed FGD wastewater and BA transport water BAT limitations and pretreatment standards are imposed on boilers with low capacity utilization.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 27

Comment Excerpt:

CWLP is a member of APPA and supports its recommendation of an alternate low utilization threshold of 1,314,000 MWh. CWLP did not independently analyze the basis for an appropriate usage threshold but supports APPA's conclusion and incorporates its arguments by reference herein. CWLP agrees that alternative threshold more accurately represents the subset of units that will incur disparate costs under the Proposed Rule without the benefit of the low utilization subcategory. Although CWLP Dallman Unit 4 has occasionally operated in excess of this threshold in the past and is designed to do so, CWLP believes that this change to the proposal alone would be sufficient to address all of CWLP' s other concerns with the establishment of a PSES of FGD wastewater.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 32

Comment Excerpt:

Certifications under PSES for Low Utilization boilers

Of the five new reporting and recordkeeping standards in the Proposed Rule, one proposes that facilities seeking the low utilization subcategory must submit an initial and annual certification. This certification must be submitted to the permitting authority and must include a calculation of the two-year average net generation for each applicable boiler, including any underlying data. EPA has proposed to require units to operate in a "low utilization" mode to qualify for the subcategory:

"When a facility seeks to have limitations for one or more subcategorized boilers incorporated into its permit, the EPA is proposing that the facility provide the permitting authority its calculation of the average of the most recent two calendar years of net generation for that boiler(s). A facility wishing to seek this subcategory, must operate below this threshold before the latest implementation dates, but a permitting authority should also refrain from establishing a 'no later thari date' which would restrict a facility from demonstrating two years of reduced net generation." 84 Fed. Reg. at 64,665.

The preamble seems to suggest the unit must have operated in low utilization mode for the two years prior to the latest applicability date that applied to that unit. This would seem to disadvantage potential low utilization boilers based on past operations, verses their best performance in the future. If a permittee is willing to certify that it will operate the unit according to the low utilization boiler threshold and requirements, the certification should be enough to qualify for inclusion in the subcategory. This approach simplifies the process for both the permittee and permitting authority. Further, EPA proposes that any failure to recertify requires compliance with the rule within two years. See§§ 423.13(g)(2)(iii)(B), 423.13(k)(2)(iii)(B).

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 33

Comment Excerpt:

Again, CWLP's position in the category of indirect discharger of FGD wastewater causes some confusion about how these provisions will be interpreted. If there is no ability to be forward looking on low utilization and not just backward looking, then CWLP is again disadvantaged from all other sources subjected to the FGD ELG who will at least be able to get their compliance timeline extended to 2025 if necessary to certify themselves as in compliance with the low utilization. CWLP is supportive of the concept of the "Tiered Limitations" and the two year compliance period for low utilization boilers that fail to comply with the net generation limitation and appreciates their inclusion for indirect dischargers as well.

As discussed above for the retirement certification, for indirect dischargers the low utilization certification would be submitted to the "control authority" rather than the "permitting authority." Assuming the control authority in this case is SCWRD, it is a little unusual for the operator of a Sanitary District, even a relatively large one as SCWRD, to have the authority and burden to evaluate issues of net generation at a power plant. It may make more sense that these certifications be submitted to the Approving Authority under the PSES program or, in the alternative, to a State NPDES or CAAPP authority whether or not they have an approved pretreatment program.

The low utilization category would apply to CWLP's smaller Units if they remain open and possibly to Unit 4 if it must choose to de-rate to maintain compliance. As explained elsewhere, CWLP would be a low utilization boiler in most years operating at current levels under the 1,314,000 MWh limit advocated by APPA. If USEPA retains the current level of treatment for Dallman Unit 4, CWLP would need to consider a forced utilization limit on Unit 4 to avoid the unnecessary and excessive costs imposed by this rule or at least to provide a feasible amount of time to achieve them. Because of the importance of such a decision, CWLP encourages USEPA to make the certification process as flexible as possible and to allow facilities to make a forward-looking certification where appropriate.

Under the proposed PSES, CWLP would be required to submit this certification by 3 years from the effective date of the rule. That means the two year period covered by the rule would begin 1 year from promulgation of the rule. CWLP is requesting clarification on what the requirement to use information from annual reports submitted to EIA would do to this time frame? CWLP believes that information contained in the annual reporting to EIA is also submitted on a more frequent basis, so CWLP encourages USEPA to consider whether it is appropriate to require use of information that has been submitted in the Spring of 2021 covering calendar year 2020 to be used in this certification or whether more flexible options that achieve the same reliability of results are available.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 8

Comment Excerpt:

Low utilization subcategory

- We support the concept of a low utilization subcategory and recommend that EPA consider restructuring the subcategory in a way that most appropriately units that may serve in a role to support electric system resiliency and reliability.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 16

Comment Excerpt:

<u>Low Utilization Subcategory</u>

NRECA appreciates EPA's recognition that low utilization units – those that serve primarily as peaking units as well as small units – function very differently from large baseload units (even those that are cycling more frequently) and warrant differential treatment as a separate subcategory. We agree with SBA, and our sister organization the American Public Power Association (APPA) that the threshold could and should be raised above the proposed 876,000 MWh (derived from estimate of <100MW units at 100% utilization). Based on an analysis by AECOM attached to the APPA comments, setting the low utilization threshold at 876,000 MWh would result in a more cost-effective rule for qualifying units based on estimated cost per TWPE (toxic weighted pound equivalent)1 removed. The AECOM analysis further demonstrates that increasing the low utilization threshold to units producing no more than 1,314,000 MWh (based on <15 MW units), or even 1,710,000 MWh (as recommended by SBA), is justified based on estimated costs per TWPE.

NRECA also supports the tiered approach for low utilization units proposed by UWAG:

- Tier 1: Units certified to operate at or below 438,000 MWh, based on a forward-looking, two-year average net generation (a level consistent with a 50 MW unit operating at full capacity) would be subject to TSS limits equivalent to BPT and would not be subject to the proposed mercury and arsenic limits for FGDW or any additional BATW measures.
- Tier 2: Units certified to operate (1) under the low utilization threshold based on a forward-looking, two-year average net generation and (2) which will retire by December 31, 2031, would also be subject to TSS limits equivalent to BPT would not be subject to the proposed mercury and arsenic limits for FGDW or any additional BATW measures.
- Tier 3: Units certified to operate under the low utilization threshold based on a forward-looking, two year average net generation and which expect to continue to operate beyond December 31, 2031, would be subject to the mercury and arsenic limits and would be subject to a BATW best management practices plan.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 105

Comment Excerpt:

XX. The Final Rule Should Include a Workable Low Utilization Boiler Subcategory.

UWAG generally supports a proposed low utilization boiler subcategory. This subcategorization will increase the resiliency of the power grid by permitting some coal-fired units that supply essential peaking or cycling power to continue to operate, while capping their net generation and, therefore, limiting pollutant discharges. These units will function primarily during emergencies or extreme weather events when the grid needs maximum capacity. Without this subcategorization, many of the low utilization boilers will be very marginal from an economic standpoint and high costs per megawatt hour (MWh) may force more unit closures.

EPA proposes that units certifying to produce less than 876,000 MWh as a two-year average annual net generation[205] (the "Low Utilization Subcategory") will be subject to FGD wastewater limits for mercury and arsenic based on chemical precipitation and will be required to minimize the discharge of BATW based on a site-specific BMP plan. 84 Fed. Reg. at 64,639; Proposed §§ 423.13(g)(2)(iii)(A), 423.13(k)(2)(iii)(A), 423.13(k)(3). If units exceed the MWh threshold required for inclusion in the Low Utilization Subcategory, EPA proposes to give them two years to comply with the same proposed FGD wastewater and BATW requirements applicable to those units outside of the subcategory. Id. at 64,667.

To qualify for the subcategory, EPA would require the permittee to provide the permitting authority with the unit's net generation for the most recent two calendar years. Id. at 64,665. The permittee also would submit updated net generation information annually. Id. at 64,666. [206]

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[205] The Proposed Rule contains inconsistent phrasing characterizing the subcategory. Proposed §§ 423.11(z) and 423.19(e)(2) use the phrase "two-year average annual net generation," while §§ 423.13(g)(2)(iii)(B) and 423.13(k)(2)(iii)(B) use the phrase "two year average net generation." Apparently, EPA wants permittees to calculate the average net generation for the applicable unit in calendar year one, then calculate the average net generation for the unit in calendar year two, and finally take the average of those two numbers to reach the "two year average annual net generation" number. UWAG requests that EPA clarify whether this understanding is correct and, if so, amend language in the Proposed Rule to clarify this understanding.

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[206] As discussed in Section XXIV, there are a multitude of factors that affect the timing of FGD wastewater or BATW technology retrofit or installation projects, many of which are out of permittees' control. As UWAG's comments illustrate, in Section XXIV, for example, two years would not be enough time to allow permittees to comply with the proposed FGD wastewater or BATW requirements from the date they no longer qualify for the subcategory. Therefore, UWAG recommends EPA reconsider its proposed timeline by allowing permittees more than two years, from the date they no longer qualify for this subcategory, to comply with the proposed FGD wastewater and BATW requirements that may be applicable to the units outside this subcategory.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 106

Comment Excerpt:

UWAG has a few recommendations for the subcategory, as outlined below.

A. UWAG Supports a Low Utilization Subcategory Threshold of At Least 876,000 MWh Average Net Generation.

EPA solicited comment on whether the Low Utilization Subcategory "should be based on alternative utilization thresholds." Id. at 64,639. Due to the relatively short comment period, UWAG was not able to complete a comprehensive review of the appropriateness of the proposed threshold across the industry. Nonetheless, it is clear that EPA has justified a threshold for the subcategory *of at least* 876,000 MWhs, based on its cost per MWh analysis. Id. at 64,639. It is possible that a higher threshold could be established based on incremental costs to the marginal units that are likely to be eligible for the subcategory; but at a minimum, the threshold should be 876,000 MWhs.

According to EPA, its proposed maximum threshold represents the subset of units that will incur "disparate costs" (defined as annualized costs per MWh produced) under the Proposed Rule without the benefit of the Low Utilization Subcategory. UWAG agrees EPA should adopt a Low Utilization Subcategory, but with some possible modifications as discussed below.

B. EPA Should Modify its Proposed Low Utilization Subcategory.

In addition to seeking comment on alternative utilization threshold values, EPA solicits comment on a possible additional subcategory for low utilization units retiring by a date after 2028 and requests data and information to support any proposed approach. Id. at 64,641. UWAG recommends an additional subcategory tier based on a later retirement/repowering date for low utilization units. UWAG offers the following possible approach for EPA's consideration.

Within the Low Utilization Subcategory, EPA should provide as follows:

- Units certified to operate below 438,000 MWhs (as a two-year average net generation) should not be subject to the proposed arsenic and mercury limits for FGD wastewater or BATW requirements. These units would be subject to TSS limits consistent with BPT.
- Similarly, units that certify to (1) operate below the 876,000 MWhs as a two-year average net generation, and (2) retire or repower by December 31, 2031[207] also should not be subject to the proposed arsenic and mercury limits for FGD wastewater or BATW requirements, but would be subject to TSS limits consistent with BPT.

Units certified to operate between 438,000 and 876,000 MWhs (or whatever higher maximum threshold EPA sets) as a two-year average net generation *without* also certifying to retire or repower would be subject to EPA's proposed FGD arsenic and mercury limits derived on the basis of the chemical precipitation model technology and the BATW requirements, as described in Section XX.D below.

UWAG's basis for proposing that units at or below the 438,000 MWhs threshold not be subject to the proposed FGD wastewater and BATW requirements for the subcategory stems from EPA's exemption of 50 MW units. The level of 438,000 MWhs is equivalent to baseload operation of a 50 MW unit. In the 2015 rule, EPA exempted 50 MW units from any additional BAT requirements. 80 Fed. Reg. at 67,849.[208] And EPA proposes to continue that exemption in this rulemaking. 84 Fed. Reg. at 64,630. Thus, any 50 MW unit may operate as a baseload unit without meeting any of the new standards imposed by the 2015 rule. Therefore, to the extent *any size unit* operates at a MWh level consistent with that of a 50 MW unit, it should be exempt from *additional* requirements for BATW and FGD wastewater, even though it will remain subject to the other BAT requirements of the 2015 rule. Any unit operating at 438,000 MWh or less will be generating very small amounts of pollutants as EPA recognized when establishing the exemption for 50 MW units.

Also, very few units are likely to make use of this portion of the Subcategory, because it is a stringent reduction in generation. For example, if subject to a 438,000 MWh cap, a 600 MW unit could operate for approximately four weeks of the year, and a 300 MW unit could operate for approximately eight weeks of the year.

UWAG also requests that EPA consider allowing permittees to certify that their low utilization units will retire or repower by December 31, 2031 and exempt these units from meeting the proposed FGD wastewater arsenic and mercury limits as well as the proposed BATW requirements for the subcategory. The suggested retirement or repowering date for this subcategory is only an additional three years beyond the proposed Retirement Subcategory window that closes on December 31, 2028. But low utilization units that will retire or repower will not be able to recoup their investment if required to install chemical precipitation treatment or other major equipment. So units certified to retire or repower between December 31, 2028 and December 31, 2031 should not be subject to any additional FGD wastewater or BATW requirements. Instead, the units would be subject to TSS limits consistent with BPT.[209]

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[207] If EPA decides to adopt UWAG's recommended additional subcategory for low utilization units certified to retire or repower, EPA should make the necessary changes to Proposed §§ 423.18, 423.19(f), and 423.19(g) to reflect the additional December 31, 2031 deadline.

[208] In the 2015 rule, EPA explained that it was exempting units with a nameplate capacity of 50 MWs or less "[i]n light of the fact that the costs per amount of energy produced are significantly and disproportionately higher for units smaller than or equal to 50 MW compared to larger units, and in light of the very small fraction of pollutants discharged by units smaller than or equal to 50 MW." 80 Fed. Reg. at 67,858. For the same reasons—disproportionate costs and very small fractions of pollutants to be discharged—it makes sense to exempt any units that will certify to operate at or below a level commensurate with a 50 MW unit operating at full capacity. Those units would also experience disproportionate costs if forced to retrofit technologies, and also will not generate much in the way of additional pollutants, because pollutant discharges generally correlate with level of energy production.

[209] Any low utilization units certified to retire or repower by December 31, 2031 that already have chemical precipitation in place, however, would be required to continue using their existing treatment systems by the anti-bypass NPDES regulations.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 107

Comment Excerpt:

C. The Low Utilization Subcategory is Justified because it Would Include Many Coal-Fired Peaking Units that Play a Key Role Across the Country.

1. Many Coal-Fired Units Operate as "Cycling" or "Peaking" Units, Which are Critical to Electric Reliability.

The Low Utilization Subcategory with appropriate modifications is justified because, as EPA notes, low utilization units "tend to operate only during peak loading" and therefore are necessary to "ensuring electricity reliability in the near term."[210] 84 Fed. Reg. at 64,639. Operating conditions for coal-fired units have rapidly changed in recent years due to market pressures and changing regulatory requirements. As a result, many coal-fired units today operate as cycling or peaking units.[211] This trend is illustrated by the overall declining capacity factor for coal, which is the "ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period."[212] In other words, the capacity factor shows how often coalfired units are used. In 2009, the average capacity factor for coal-fired generation was 64.2 percent, but it dropped to 53.6 percent in 2018, and, as of October 2019, the average capacity factor was just 48.05 percent.[213]

Peaking and cycling units are critical components of an interconnected system that provides reliable power to the BPS. Every year NERC issues a summer and winter reliability assessment that "identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming … season." NERC, *Summer Reliability Assessment at 3* (June 2019) (the "SRA"); NERC, *2019-2020 Winter Reliability Assessment at* 4 (Nov. 2019) (the "WRA"). The SRAs and WRAs project peak electricity demand and supply changes that could impact the BPS across the country. SRA at 3; WRA at 4. During Summer 2019 and Winter 2019-2020, for example, MISO's[214] and Southwest Power Pool's ("SPP's")[215] on-peak capacity generation mix was projected to be 30-50 percent coal-based. SRA at 14, 25; WRA at 16, 28. MISO's and SPP's coal-based on-peak capacity, therefore, was critical to NERC's finding that their resources met requirements under normal peak load scenarios. SRA at 14, 25; WRA at 28.

In addition, as renewable generation sources continue to contribute more to on-peak capacity generation, reliance on coal-fired peaking and cycling units will become more important, especially during winter months. For example, during January 2019, a cold snap caused generation forecasts to overestimate wind resource contributions by as much as 8 GW – over 56 percent of installed wind generation capacity in the MISO area. WRA at 12. In part, forecasters failed to account for low-temperature cutoff thresholds for some wind turbine generators and the extreme weather event forced MISO operators to implement emergency procedures. Id. at 12. Because coal-fired peaking and cycling units comprised close to 50 percent of MISO's peak capacity generation mix, see id. at 16, they were critical to filling resource shortfalls during the extreme weather event to compensate for variable wind resources.

Maintaining some diversity among power sources is also critical to system stability. In January 2019, a fire at a gas compressor station during a sub-zero cold snap led to emergency measures to reduce natural gas usage, including closure of several major manufacturing facilities and an appeal to residential customers to lower their thermostats.[216] In the event of gas pipeline ruptures or other equipment failures, the ability to use coal-fired units could help to alleviate the emergency.

In addition, as record-breaking weather patterns occur more frequently in some parts of the country and large power plants retire, grid operators will increasingly rely on peaking units to respond to extreme conditions. For example, during summer 2018, ERCOT estimated an 11 percent reserve margin, lower than previous years' estimates of 13.75 percent, due to the retirement of three coal plants and abnormal temperatures.[217] Reserve margins are the difference between the maximum available supply (i.e., capacity) and demand (including expected peak demand).[218] Adequate reserve margins are important because they represent the grid's ability to adjust to abnormal conditions when necessary. Peaking units are essential to maintaining adequate reserve margins and make it easier for the grid to operate effectively during abnormal conditions.

2. Discouraging Continued Operation of Peaking or Cycling Units Would Disproportionately Affect Rural Areas.

Facilities that operate peaking and cycling coal-fired units are often located in rural areas. These facilities provide much-needed employment stability and contribute to the tax revenues that support local schools and government. For example, in 2018, when two coal-fired power plants closed in Adams County, Ohio, "with a population of about 28,000 and already one of the poorest corners of Ohio," the area lost its "highest-paying jobs, its largest employers, its biggest taxpayers and, in many ways, its lifeblood."[219]

Indeed, "[r]ural communities often are more dependent on these declining sectors and are less able to diversify into growing sectors that rely on access to metropolitan markets and an educated labor force."[220] UWAG urges EPA to consider the potential benefits of the Low Utilization Subcategory to rural communities that cannot easily diversify their economies and are dependent on coal-fired units for substantial revenues.

3. Peaking and Cycling Coal-Fired Units Produce Substantially Smaller Amounts of FGD Wastewater and BATW than Baseload Units.

Wastewater production—including BATW and FGD wastewater—directly correlates to coal-fired generation. When generation is reduced, wastewater production is reduced by a similar percentage. As discussed in Section XII.B., EPA's data on net generation shows that the percent utilization of the generating units expected to produce FGD wastewater is relatively low. For example, for units operating at less than 876,000 MWh, their average utilization rate is approximately 26.80 percent,[221] which indicates significantly less discharge of pollutants than units operating at 100 percent capacity.

In addition, in the 2015 rule, EPA explained that it was exempting units with a nameplate capacity of 50 MWs or less "in light of the very small fraction of pollutants discharged by units smaller than or equal to 50 MW." 80 Fed. Reg. at 67,858. In short, EPA found a direct relationship between generation and the amount of pollutants discharged, and based an exemption on that relationship. In the same way, peaking and cycling units produce significantly less wastewater than if they operated as baseload units.[222]

[210] EPA assesses this issue under the statutory factor of "non-water quality environmental impacts (including energy requirements)." CWA § 304(b)(2)(B). This issue also could be considered under the statutory factor for "such other factors as the Administrator deems appropriate." Id. The resiliency and reliability of the power system is certainly an issue that merits consideration in this rulemaking.

[211] For reference, baseload generating units typically operate 24 hours per day, year-round; peaking units typically operate when hourly loads are at their highest, usually during summer and winter months; and cycling units operate between baseload and peaking generators by varying their output to adapt to daily and annual demand changes. EIA, *Electric generator dispatch depends on system demand and the relative cost of operation* (Aug. 17, 2012), https://www.eia.gov/todayinenergy/detail.php?id=7590# (last visited Dec. 23, 2019); see also 84 Fed. Reg. at 64,638 ("While the majority of boilers in 2009 were base load, making nameplate capacity a good indicator of electricity production, coal-fired boilers today often operate as cycling or peaking boilers, responding to changes in load demand.").
[212] EIA, *Glossary*, https://www.eia.gov/tools/glossary/index.php?id=Capacity_factor (last visited Jan. 19, 2020).
[213] See EIA, *Electric Power Monthly,* Table 6.07.A (Nov. 26, 2019), https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a (last visited Dec. 23, 2019).
[214] MISO "is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency." It "manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers." SRA at 14.
[215] The SPP "Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming." Its "assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million people." Id. at 25.
[216] U.S. News & World Report, *Bitter Cold and Natural Gas Shortages Shutter Auto Plants* (Jan. 31, 2019), https://www.usnews.com/news/best-states/michigan/articles/2019-01-31/bitter-cold-naturalgas-shortages-shutter-auto-plants (last visited Dec. 29, 2019).
[217] EIA, *Coal Plant Retirements and High Summer Electricity Demand Lower Texas Reserve Margin,* (July 2, 2018), https://www.eia.gov/todayinenergy/detail.php?id=36593 (last visited Jan. 3, 2020).
[218] EIA, *Reserve Electric Generating Capacity Helps Keep the Lights On,* (June 1, 2012), https://www.eia.gov/todayinenergy/detail.php?id=6510 (last visited Jan. 3, 2020).
[219] Brady Dennis & Steven Mufson, *In small towns across the nation, the death of a coal plant leaves an unmistakable void,* WASH. POST (Mar. 28, 2019), https://www.washingtonpost.com/national/health-science/thats-what-happens-when-a-big-plant-shutsdown-in-a-small-town/2019/03/28/57d62700-4a57-11e9-9663-00ac73f49662_story.html?arc404=true (last visited Dec. 23, 2019).
[220] Mark Haggerty, *Communities at Risk from Closing Coal Plants,* HEADWATERS ECONOMICS (Mar. 2017), https://headwaterseconomics.org/energy/coal/communities-coal-plant-closures/ (last visited Dec. 20, 2019)
[221] *See supra* at Section XII.B, Table "Percent Utilization Information."
[222] By certifying that they will operate their units as low utilization units, permittees adopt process changes suitable for low utilization, including changes in operation and maintenance schedules. Consideration of process changes is another statutory factor that EPA may take into account when determining BAT. CWA § 304(b)(2)(B).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 111

Comment Excerpt:

E. The Net Generation Calculation Should Account for Dual-Fueled Units.

Some power plants have or are planning to add dual-fueled units. These units can burn coal or some other non-coal fuel, such as natural gas. UWAG recommends that EPA clarify how the Low Utilization Subcategory would work for facilities with dual-fueled units.

For instance, it is not clear how EPA intends to calculate net generation for dual-fueled units. To resolve this issue, UWAG recommends that EPA insert language in the certification requirements that requires permittees with dual-fueled units to calculate the two-year average annual net generation by accounting for the fraction of coal-fired generation only. A dual-fuel unit does not generate FGD wastewater or BATW during gas-fired operations, so it makes sense that only the coal-fired fraction of the generation would be included for purposes of calculating the average annual net generation that determines eligibility for the Low Utilization Subcategory. In other words, the Low Utilization Subcategory should include units that burn coal up to a maximum of 876,000 MWh (or whatever other maximum threshold EPA sets) as a two-year average net generation. Dual-fueled units should only be required to include generation from coal when determining whether the unit is below the maximum MWh threshold. Generation (MWhs) during gas-fired, or other non-coal-fired, operations should not be included when determining whether a unit qualifies for the subcategory.

Calculating the net coal-fired generation for a dual-fueled unit is straightforward and something the permittee could provide to EPA. Permittees with coal-fired units must submit quarterly electronic data reports ("EDRs") under the CAA Acid Rain Program. See 40 C.F.R. §§ 75.57(a), 75.64(a). Permittees report gross generation in MWh by fuel type in their EDRs. The data that are gathered by the EDRs are detailed (hourly averages), high quality (meets QA/QC requirements), and publicly and electronically available. See EPA, *Air Markets Program Data,* https://ampd.epa.gov/ampd/ (last visited Dec. 20, 2019). Therefore, these data are often used for research and rule development. Given the reliability and availability of the gross generation data by fuel type, EPA could require permittees to use data in their Acid Rain Program EDRs to help calculate the two-year average net generation for dual-fueled units. Permittees could begin with the gross coal-fired generation numbers for the unit from the Acid Rain Program reports and then if necessary, apportion facility-wide energy consumption by boiler nameplate to arrive at net coal-fired generation. 84 Fed. Reg. at 64,665.[227] As with EIA data, the use of the Acid Rain Program data will eliminate unnecessary paperwork burdens and duplication of efforts. In addition to calculating the net coal-fired generation, the permittee also could report the unit's total net generation based on EIA information.

While EPA indicates a preference for use of EIA data,[228] for dual-fueled units, using a combination of Acid Rain program reports and EIA data would provide clarity of method and use existing, relevant, and high quality data already being reported.[229]

[227] As EPA indicates, it may be possible to adequately document "a sufficient rationale for an alternate apportionment." 84 Fed. Reg. at 64,665. UWAG agrees that, if the permittee can establish a better rationale for apportioning facility-wide consumption, it should be allowed to use the alternate method.
[228] Id. at 64,665 (the net generation average "should primarily be collected and calculated using data developed for reporting to the EIA"…).
[229] If EPA agrees that Acid Rain EDRs should be used to calculate net generation for dual-fueled units, then it should amend the language in § 423.19(e) because it requires that the certification be "based on the information submitted to the Energy Information Administration…."

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)

Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 112

Comment Excerpt:

F. EPA Should Provide Some Flexibility Over the Timing of When the Initial Certification Must Be Submitted to Permitting Authorities.

In order for units to be included in the Low Utilization Subcategory, EPA proposes that the permittee submit an initial certification followed by annual recertification thereafter. Proposed § 423.19(e). The initial certification would need to be submitted to a permitting authority with a permit application, but the permittee also would be required to operate below the Low Utilization Subcategory threshold before the latest implementation dates. Id. see also 84 Fed. Reg. at 64,665.

UWAG recommends EPA clarify this provision by requiring the initial certification on or before December 31, 2023.

For permittees with pending applications or for those with applications due very soon after the effective date of the final rule, an approximately three-year window for claiming eligibility under the Low Utilization Subcategory provides time to make a reasoned decision in light of the final ELG rule and proposed amendments to the CCR rule. As discussed in Section XV.B.1, permittees will need time to analyze the final rule and seek regulatory approvals necessary for any final decision to retrofit, retire, or repower their units. As part of this analysis, permittees will need to consider how their low utilization units fit into their overall plans to comply with the final rule and other regulations.

A “no later than” date of December 31, 2023 will also harmonize with UWAG’s proposal for the Retirement Subcategory certification in Section XVI. Therefore, UWAG’s proposed date will promote simplicity and ease the burden of complying with multiple, varying deadlines.

The decision whether to adjust operations to include certain units in the Subcategory is tied to many other factors, such as how many units permittees will retire or repower. Therefore, the no later than date of December 31, 2023, gives permittees the flexibility and time they need to make informed decisions and accrue the data necessary to certify low utilization units.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 113

Comment Excerpt:

G. Eligibility for Inclusion in the Subcategory Should be Based on the Certification, Not Past Operations.

EPA has proposed a strict limitation to the Low Utilization Subcategory by requiring units to have operated in a "low utilization" mode as a condition for qualifying for the subcategory. The preamble describes this limitation as follows:

When a facility seeks to have limitations for one or more subcategorized boilers incorporated into its permit, the EPA is proposing that the facility provide the permitting authority its calculation of the average of the most recent two calendar years of net generation for that boiler(s). A facility wishing to seek this subcategory, must operate below this threshold before the latest implementation dates, but a permitting authority should also refrain from establishing a 'no later than date' which would restrict a facility from demonstrating two years of reduced net generation.

84 Fed. Reg. at 64,665. Apparently, EPA means that, to qualify for the Low Utilization Subcategory, a unit must have operated in low utilization mode for the two years prior to the latest *applicability* date that applies to the unit. But this provision would arbitrarily exclude potential low utilization boilers only on the basis of past operating history, instead of their best use going forward.

Assume, for example, the Agency publishes the final rule in June 2020 and a permitting authority then requires two separate permittees to meet BATW limits by October 2021, roughly 15 months after the final rule is published. To take advantage of the Low Utilization Subcategory, the owner of the first unit would have had to limit its operations to the threshold level nine months prior to publication of the final rule, or make radical reductions in MWHs ones a shorter time frame. Compare this unit's situation to that of a hypothetical second unit that experienced a longer-than-usual outage in the nine months before the rule's publication. As a result, the latter unit would qualify for inclusion in the Low Utilization Subcategory, while the former unit would be excluded. This is an inequitable result.

EPA's intent in proposing the Low Utilization Subcategory seems to be to avoid shuttering marginal units that have a critical peaking/emergency use function. But the permittee is in the best position to determine which units are worth including in the subcategory, and that determination is best done on the basis of the unit's *future* role in overall company plans for system resiliency and reliability—not on its past operations. Therefore, if a permittee is willing to certify that it will operate the unit according to the low utilization thresholds and requirements, the certification should be sufficient to qualify for inclusion in the subcategory. This simplifies the eligibility procedures, which is a significant benefit to both the permittee and the permitting authority. And there is little risk in taking this approach, because EPA proposes that any failure to recertify requires full compliance with the Proposed Rule within two years. Proposed §§ 423.13(g)(2)(iii)(B), 423.13(k)(2)(iii)(B). [230]

[230] As previously discussed, however, UWAG recommends EPA reconsider its proposed timeline by allowing permittees more than two years, from the date they no longer qualify for

this subcategory, to comply with the proposed FGD wastewater and BATW requirements that may be applicable to the units outside this subcategory.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 114

Comment Excerpt:

XXI. UWAG Supports a "Safe Harbor" Provision for the Proposed Retirement and Low Utilization Subcategories, with a Few Recommended Modifications.

The Agency proposes to require that permits include a "safe harbor" condition for units that qualify for the low utilization boiler or Retirement Subcategories to continue to operate (despite qualifying for inclusion in the subcategories) "in case of an emergency order issued by the Department of Energy ["DOE"] under Section 202(c) of the Federal Power Act or a Public Utility Commission reliability must run agreement ["RMR agreement"] …." Proposed § 423.18(a). In such circumstances, permittees must submit a one-time certification to permitting authorities no later than 30 days from receipt of such order or agreement. Proposed § 423.19(g).231 The certification must demonstrate that the unit would otherwise qualify for the subcategory absent the emergency order or RMR agreement and provide a copy of the order or agreement. Proposed § 423.19(g).

UWAG commends EPA's recognition that there may be certain circumstances, out of permittees' control, that would prevent them from otherwise meeting requirements of certain subcategories. UWAG believes, however, for all of the reasons discussed in Section XV.A. above, that the safe harbor provision should also include protection for coal-fired units certified to be repowered.

In addition, power utility companies operate under a number of varying governance structures across the country. They operate in regulated and deregulated markets with oversight by organizations such as federal agencies, state agencies, ISOs/RSOs, or state legislatures. It is conceivable that any number of the entities with authority over power utility companies may order them to continue operating for reliability purposes.

For example, "RMR agreements are contracts between the [Independent System Operator (ISO)] and a generation unit.…"[232] Generally, services provided under RMR agreements, or equivalent types of agreements,[233] "provide for retention of generation units wishing to deactivate … but which are needed for transmission system reliability."[234] In some cases, the ISO is the approval authority. For example, the Public Utility Commission of Texas has issued rules stating "[a]ll recommendations by ERCOT[235] staff to enter into an RMR or MRA service agreement will be subject to approval by the ERCOT governing board." Texas Admin. Code § 25.502(e)(5). ERCOT's procedures are consistent with the Texas Admin. Code.[236] The Agency's Proposed §§

423.18(a) and 423.19(g)(2), however, limit the safe harbor provision to a "*Public Utility Commission* reliability must run agreement." (emphasis added).

In addition, while the DOE certainly has the power to issue emergency orders under Section 202(c) of the Federal Power Act ("FPA") to require companies to continue operating their units, it is conceivable other governing bodies could also require continuing such operations. For example, FERC, an independent commission, has responsibility for regulating "the transmission and wholesale sales of electricity in interstate commerce."[237] And FERC may exercise authority pursuant to the FPA that does not necessarily arise under Section 202(c). In fact, there is precedent to support FERC taking action that could require companies to continue operating for reliability purposes under other sections of the FPA. *See, e.g., San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Service,* 95 FERC ¶ 61,115, 10 (Apr. 26, 2001) (requiring California power generators, including non-public utilities, to offer all of their capacity to the ISO during all hours, if available).

Given the complex regulatory framework in which power utility companies operate and the reasons described above, UWAG recommends that EPA amend the language in Proposed § 423.18(a) to include the words in bold below:

In case of **(1) an order issued by a regulatory authority, an independent system operator, a regional transmission organization, or similar body acting under and authorized by applicable law, including but not limited to the Federal Power Act; or (2) a legally binding reliability must run agreement, or similar agreement regardless of its name,** a **unit** shall be deemed to qualify as a low utilization boiler or **unit** that will be retired from service by December 31, 2028[238] if such qualification would have been demonstrated absent such order or agreement.

For consistency, UWAG also recommends EPA amend the language in Proposed § 423.19(g)(2) to include the words in bold below.

A certification statement must demonstrate that a **unit** would have qualified for the subcategory at issue **absent an order issued by a regulatory authority, an independent system operator, or regional transmission organization, or similar body acting under and authorized by applicable law, including but not limited to the Federal Power Act; or (2) a legally binding reliability must run agreement, or similar agreement regardless of its name;** and a copy of such order or agreement shall be attached.

[231] There appears to be a citation error in Proposed § 423.19(g)(1). The section provides that sources seeking to apply the protection of the "safe harbor" provision (which would include both the units scheduled to be retired or repowered as well as low utilization units that may, by order, exceed their MWh threshold) should submit a one-time certification "no later than 30 days from receipt of the order or agreement attached pursuant to paragraph (f)(2) of this section." The reference to "paragraph (f)(2)" should be amended to "paragraph (g)(2)" instead, which proposes to require the permittee to attach a DOE emergency run order or a PUC reliability must run agreement to the certification.

[232] Michael Giberson, *Integrating Reliability-Must-Run Practices Into Wholesale Electricity Markets,* R STREET POLICY STUDY No. 114, 2 (Oct. 2017) (the "R-Street Policy Study").

[233] RMR agreements do not consistently go by the same name across the country. See Federal Energy Regulatory Commission ("FERC") NYISO Order. at 1 n.3 ("The services are designated as RMR or 'Reliability Support Services' (RSS) in the various agreements. We will generally refer to such services as RMR services here."); R-Street Policy Study at 2, n.1 ("The comparable Midcontinent ISO practice is termed system support resource (SSR) service. For consistency within this document, all comparable practices will be described as RMR service and that term should be assumed to apply to MISO SSR service unless indicated otherwise.").
[234] Order Instituting Section 206 Proceeding and Directing Filing to Establish Reliability Must Run Tariff, *In re: N.Y. Independent System Operator, Inc.,* 150 FERC ¶ 61,116, 1-2 (FERC Feb. 19, 2015) (the "FERC NYISO Order").
[235] "The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 26 million Texas customers—representing about 90 percent of the state's electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 46,500 miles of transmission lines and 600+ generation units. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for 8 million premises in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature." ERCOT, *Company Profile,* http://www.ercot.com/about/profile (last visited Jan. 19, 2020).
[236] ERCOT Nodal Protocols, § 3.14.1.3(2) (Nov. 1, 2019) ("ERCOT shall execute the RMR or MRA Agreement as soon as feasible after receiving ERCOT Board approval to do so."), http://www.ercot.com/mktrules/nprotocols/current (last visited Jan. 20, 2020).
[237] See FERC, *About FERC - What FERC Does,* https://www.ferc.gov/about/ferc-does.asp (last visited Jan. 19, 2020).
[238] If EPA decides to adopt UWAG's recommended approach for the Low Utilization Subcategory in Section XX.B., which includes an additional subcategory for low utilization units certified to retire or repower by December 31, 2031, EPA should further amend Proposed § 423.18(a) to reflect the new subcategory.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 115

Comment Excerpt:

XXII. EPA Should Clarify Ambiguities in Sections Related to the Proposed Retirement and Low Utilization Subcategories.

Proposed §§ 423.18(a), 423.19(f), and 423.19(g) use the terms "units" and "boilers" interchangeably, which could lead to confusion and create unnecessary ambiguity. UWAG recommends that EPA revise these proposed sections to consistently reference "units" rather than "boilers."

In addition, as UWAG states above in Section XVII, EPA should not require permittees to require other documentary evidence with the proposed Retirement Subcategory certification statement. In the event, however, EPA chooses to maintain those requirements in the final rule, UWAG urges it to clarify or define the term "most recent integrated resource plan" in Proposed § 423.19(f)(2). This term could be construed to refer to an IRP recently submitted to a state utility commission for approval or the last IRP approved by that agency. This is a critical distinction because unapproved IRPs are subject to modification or rejection by state utility commissions and a permittee might not yet have an approved IRP by the time it must submit a certification. To clarify this critical ambiguity, UWAG recommends that EPA define "most recent integrated resource plan" to mean "the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs."

Finally, EPA should clarify ambiguities in the Preamble that conflate the concepts of coal combustion and electricity production. EPA proposes that facilities seeking inclusion in the Retirement Subcategory "submit a one-time certification to the permitting authority stating the date of expected retirement *from the combustion of coal, and* provide a citation to … documentation in support of that date. This citation is meant to provide the permitting authority further evidence that a boiler will, in fact, *cease the production of electricity* by that date." 84 Fed. Reg. at 64,667 (emphasis added). Combustion of coal and production of electricity are not the same. And, as discussed in Section XV.A.1, n.153, discharges from coal-fired units are the focus of this rulemaking. So, for units that are included in the Retirement Subcategory because they are certified to be retired or repowered, the requirement should be that those certified units cease coal-fired operations (i.e., coal combustion) by December 31, 2028,[239] because ceasing coal-fired operations means that the unit will also cease generating BATW and FGD wastewater. The focus should not be on whether a unit ceases electricity production because, for example, a repowered unit still produces electricity and would be allowed to continue after December 31, 2028. Thus, EPA should clarify that evidence of ceasing electricity production is not required for inclusion in the Retirement Subcategory.

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[239] This certification should also include a December 31, 2031 date if EPA adopts UWAG's recommended additional subcategory for low utilization units certified to be retired or repowered.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 42

Comment Excerpt:

VII. SOUTHERN COMPANY SUPPORTS THE LOW UTILIZATION BOILER SUBCATEGORY AND RECOMMENDS CERTAIN MODIFICATIONS

A. Continued Operation of Low Utilization Boilers is Useful for Ensuring Reliable and Resilient Service.

EPA is correct that many coal units are producing fewer and fewer MWh per year and tend to operate only during peak loading.[89] These units are becoming increasingly important for ensuring reliable and resilient electricity service to customers but are also subject to increasingly disparate cost impacts from any new environmental regulations. As utilization of these coal units continues to decline, owners must balance the economic benefits of retirement and ability to take advantage of low gas prices against a potential risk of future gas supply. As one recent example, Georgia Power Company, in its 2019 IRP filing, stated:

In this IRP, the Company is proposing to retire an additional 982.5 MW of coal capacity at Plants Hammond and McIntosh. These retirements are also in the best economic interests of customers, and do not impact the Company's ability to maintain a sufficient reserve margin. However, these units have been called into action over the past several years and have aided the resilience and reliability of the System since the 2016 IRP, all while under spending limitations. As future coal retirements remain possible, the Company will need to balance the economic benefits of retirement and the ability to take advantage of low-cost gas commodity prices against the potential risk associated with gas fuel supply. Striking the right balance requires consideration of numerous options such as energy storage, inactive reserve, or fuel storage, which may preserve on-site fuel while minimizing spend. These items could prove to be an important resilience consideration with respect to potential future retirement decisions . . . . [90]

It is therefore appropriate for EPA to establish a subcategory that would decrease the cost impacts for units that serve in an increasingly limited, but important, capacity.

89 Proposed Rule, 84 Fed. Reg. at 64,638, 64,638 n.60.
90 Ga. Power Co., 2019 Integrated Resource Plan C-28, Ga. Pub. Serv. Comm'n Docket No. 42310 (2019).

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 43

Comment Excerpt:

B. EPA Should Ensure Facilities are Given Sufficient Time to Demonstrate Low Utilization.

Ideally, EPA would not require two years of net generation below the 876,000 MWh threshold to qualify for this subcategory. Depending upon the applicability dates provided in permits, this requirement could effectively preclude qualification for many units trending toward low utilization but that do not yet have two years below the threshold before they must fully implement BAT. Once the applicability dates have passed, there is little benefit to qualification. Removing the need to demonstrate low utilization prior to qualification avoids this scenario, but it still allows EPA to ensure low utilization prospectively. After qualification, the permittee would need to provide net generation data in its first periodic recertification.

If EPA nonetheless retains a backward-looking demonstration based on historical net generation, it should, at a minimum, clarify the current proposal to preserve the opportunity for demonstration. For direct-discharge facilities, the proposed rule requires an initial certification of low utilization status "with a permit application."[91] On the face of this rule, a facility can seek coverage under the subcategory at any time it files an application.[92] Southern Company interprets the phrase "permit application" to include applications submitted to modify or reopen a permit and requests that EPA confirm this understanding in the final rule.[93] Under this view, the certification proposal creates an option for seeking coverage, but not a legal deadline for doing so.

The preamble to the proposed rule, however, states that "[a] facility wishing to seek this subcategory[] must operate below th[e 876,000 MWh] threshold before the latest implementation dates[.]"[94] The legal basis of this statement is unclear; no requirement to apply prior to the implementation dates appears in the proposed text. Southern Company agrees nonetheless that the implementation (or applicability) dates drive the economic incentive to seek coverage. Once a facility has incurred capital costs to implement the most advanced treatment technology, there is less benefit to qualifying as a low utilization boiler. Southern Company requests that EPA clarify the statement in the preamble to the proposed rule and when the initial certification may be submitted.

The preamble to the proposed rule further states that "a permitting authority should also refrain from establishing a 'no later than date' which would restrict a facility from demonstrating two years of reduced net generation."[95] Southern Company agrees that the factors listed in the current version of 40 C.F.R. § 423.11(t) should allow the permitting authority to craft an applicability date that provides enough time to demonstrate low utilization.[96] Southern Company is nonetheless concerned that, because the applicability date factors were not promulgated with an explicit recognition for the proposed subcategories, the relevance of EPA's preamble statement will be disputed in later proceedings. This problem may be particularly acute for facilities that have already received applicability dates under the 2015 rule. The company thus urges EPA to recognize time for low utilization demonstration as an explicit factor in setting applicability dates at 40 C.F.R. § 423.11(t). A preamble statement is no substitute for crystal clear regulatory text.

91 Proposed Rule, 84 Fed. Reg. at 64,677 (to be codified at 40 C.F.R. § 423.19(e)(1)).
92 The phrase "a permit application" stands in contrast to the proposed deadline for retirement certification, which is due with "the permit application[.]" Id. Southern Company interprets the latter provision to mean the first permit application after the final rule takes effect.
93 See, e.g., Ohio Valley Envtl. Coal., Inc. v. Coal-Mac, Inc., 775 F. Supp. 2d 900, 908-09 (S.D. W. Va. 2011) ("Independence filed an application to obtain a modification of this permit. . . . Jacks Branch applied for a modification of the permit[.]"); see also 81 Fed. Reg. 38,645, 38,653 (proposed June 14, 2016) ("[S]ources may apply for a permit modification from their permitting authority at any time."). Excluding permit modifications would likely make the proposed subcategories unworkable in practice. The ability to submit the necessary certification would depend on the timing of the facility's permit renewal cycle, which would be a matter of luck. EPA should not issue such a rule.
94 Proposed Rule, 84 Fed. Reg. at 64,665.
95 Id.
96 For instance, the "[t]ime to expeditiously plan" should include the time required to plan a glidepath towards low utilization, and "[c]hanges made or planned . . . in response to" other major environmental regulations should include changes in utilization. 40 C.F.R. § 423.11(t)(1)- (2). Finally, time to demonstrate low utilization can also be an "[o]ther factor . . . appropriate" to delaying full BAT implementation. Id. § 423.11(t)(4).

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 44

Comment Excerpt:

C. EPA Should Add Subcategories (1) for Boilers Operating at or below a Yearly Threshold of 438,000 MWh Per Year and (2) for Boilers Operating between 438,000 to 876,000 MWh Per Year that also Commit to Retire by 2030.

While Southern Company supports the proposal for a low utilization boiler subcategory, it remains concerned that the BAT standards proposed for the category, particularly chemical precipitation, will impose disproportionate costs. EPA's FGD cost database illustrates that chemical precipitation accounts for the lion's share—between 69% and 78%—of the capital costs of meeting the non-subcategory numeric limitations for FGD wastewater.[97] This implies that coverage under the subcategory can save approximately 22% to 31% of capital costs. This range of savings does not appear to solve, at least fully, the problem of disproportionate costs experienced by low utilization boilers.[98] Alternatively, these costs will dissuade facilities from committing to low utilization in the first place, resulting in greater effluent discharges and non-water quality environmental impacts like air emissions.

Southern Company proposes a two-prong solution to better align costs and benefits. First, EPA should establish a separate subcategory for units with utilization at or below an annual threshold of 438,000 MWh per year. This net generation threshold is the equivalent of a 50 MW boiler operating at 100% capacity. For these units, BAT should be set as numeric limitations for TSS. These are the same limits imposed on boilers with a 50 MW nameplate capacity,[99] and boilers that have committed to operate at the same maximum capacity should bear similar costs.[100] The certification under this subcategory would simply substitute a legal limit (the equivalent of 50 MW net generation) for the physical limits (nameplate capacity) inherent to small boilers.

As a second prong of the solution, EPA should establish a separate subcategory for boilers operating between 438,000 MWh per year and 876,000 MWh per year *that also commit to retire by 2030*. EPA expressly requested comment "on whether an additional subcategory for low utilization boilers retiring by a date certain that is after 2028 would be warranted," [101] and Southern Company believes that such a subcategory could further remedy the problem of disproportionate costs if it applied numeric limitations on TSS similar to those for units below 50 MW nameplate capacity. As EPA noted in the preamble to the proposed rule, units with relatively high rated capacity but low capacity utilization "are expected to produce fewer and fewer MWh per year."[102] Southern Company agrees that this trend is likely to "mov[e] those boilers further toward the high $/MWh costs over time,"[103] which makes it all the more appropriate to forego chemical precipitation to avoid disproportionate costs. But a commitment to retire by 2030104 simultaneously limits the aggregate pollutant loading from these units, in addition to limiting their non-water quality environmental impacts. A cap on the total lifetime discharges from the facility is a reasonable substitute for more stringent treatment of each individual discharge in perpetuity.

97 See EPA, FGD Cost Database (2019) (Docket ID No. EPA-HQ-OW-2009-0819-8149).
98 For instance, EPA has illustrated the disproportionate costs of chemical precipitation plus biological treatment in Figure VIII-1 of the preamble. See Proposed Rule, 84 Fed. Reg. at 64,639. While this Figure shows the large majority of boilers experiencing per-MWh costs of $2.00 or below, it also shows that many low utilization boilers experience unit costs of $4.00 or more (and in some cases much more). Thus, the BAT standards for this subcategory would need to reduce unit costs by at least 50% to bring these boilers in line with the economic burden imposed on the rest of the industry. Removing biological treatment alone does not meet that goal.
99 See 40 C.F.R. § 423.13(g)(2) (applying TSS limits at 40 C.F.R. § 423.12(b)(11)).

100 In fact, even these limits might still impose relatively higher costs on units operating at a 50 MW equivalent despite higher rated capacity. Boilers with a higher nameplate capacity might experience greater operational costs to stay below the 50 MW equivalent limit.
101 Proposed Rule, 84 Fed. Reg. at 64,641.
102 Id. at 64,639.
103 Id.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 45

Comment Excerpt:

D. EPA Should Add Alternative Utilization Criteria Based on Capacity Factor.

EPA has asked for comments on alternative utilization thresholds.[105] EPA could consider including a 15% capacity factor limitation as a separate basis for subcategory qualification.[106] Despite the decline of coal generation, large coal units will continue to play important roles in ensuring resiliency and reliability. However, there could be instances where a proposed utilization threshold in MWh/yr may limit the ability of larger, more efficient units to serve in this critical role. Larger generating units have turndown ratios and associated minimum loads that cannot achieve the same absolute net generation as smaller units, but those constraints are of less concern when the unit is operating for a limited period each year. Stated another way, larger units cannot feasibly run at low loads each day, but they can run for fewer days.

There are advantages for utilizing larger units for this limited purpose. Larger units generate electricity more efficiently when they are running, and they are more likely to have already installed additional environmental controls beyond wastewater treatment. Also, the total nameplate capacity of larger units helps ensure a more robust margin of safety in situations where sudden, significant generation shortfalls arise. Southern Company suggests a 15% capacity factor as approximately equal to the combined months of January and February, when our traditional service territory can experience the need for additional capacity due to significant cold weather periods or unforeseen generation shortfalls. A 15% capacity factor limitation could also ensure that all sizes of generating units could be more fully and appropriately utilized in the role that EPA has envisioned, which is for the critical purpose of ensuring resiliency and reliability. We recommend that EPA take the same approach toward initial and continued qualification for this subcategory, which is to demonstrate two years of generation, on average, below this capacity factor.

104 While Southern Company proposes a 2030 deadline for retirement, it acknowledges that a later date might also be appropriate. Southern Company views 2030 as a reasonable balance among planning uncertainty, protection of customer interests in a balanced generation portfolio, and environmental impacts.
105 Id.

106 In other words, a facility could qualify for the subcategory through meeting either the 876,000 MWh criterion or the capacity factor criterion.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 13

Comment Excerpt:

Subcategory for Low Utilization Boilers

EPA proposes to implement a new subcategory for low utilization boilers, i.e., boilers with an annual net generation less than 876,000 MWh per year. Boilers operating below the generation threshold experience dissimilar costs per MWh produced as compared to boilers operating above that threshold. Duke Energy agrees with EPA's conclusion and the proposed BAT limits for these units. EPA's selected technology of chemical precipitation as BAT for FGD wastewater are cost-effective, can remove 90% of the pollutant loading from FGD wastewater and can be employed across all geographical regions under different operating scenarios. Unlike biological systems, chemical precipitation systems do not rely on living organisms to treat the water making them optimal treatment systems for units that experience long-durations without operating, which is likely to be the case for units qualifying for the low utilization subcategory.

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 7

Comment Excerpt:

Source Subcategory for Low-Utilization Units

America's Power supports EPA's proposal to establish a new source subcategory for affected coal-fired electric generating facilities with low utilization levels. For the reasons discussed below, the establishment of this subcategory will lower the disproportionately high compliance costs, and resulting competitive disadvantage, that would otherwise be incurred by low-utilization generating facilities.

For this new subcategory of electric generating facilities, the Agency would set discharge limitations based on different reference control technologies that are incrementally less stringent than the technologies used by EPA for setting the proposed new limitations for FGD wastewater and BA transport water. Those reference control technologies are chemical precipitation for reducing mercury and arsenic from FGD wastewater and gravity settling with surface impoundments, in combination with best management practice plans for reducing total suspended solids from BA transport water.

Effluent discharge limitations based on these technologies will therefore lower the overall compliance costs for this subcategory of low-utilization generating units that are becoming increasingly uncompetitive due to higher costs. Furthermore, the establishment of a subcategory for low-utilization units makes sense given that most existing coal-fired units were operated at one time as baseload generating facilities but are now dispatched as load-following units or just operate for short durations to meet peak demands in the summer or winter.

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 8

Comment Excerpt:

To qualify as a low-utilization generating unit, the proposed rule requires that the two-year annual net generation of each unit not exceed 876,000 megawatt-hours per year (equivalent to a 400 MW coal-fired boiler operating at a 25 percent capacity factor). America's Power supports the use of a two-year average for determining the eligibility of a low-utilization unit. Most importantly, this approach will help to minimize the potential repercussions of any sudden unplanned increases in a unit's annual net generation levels due to unforeseen circumstances, such as extreme weather or forced outages of other generating units within an electricity utility system.

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 9

Comment Excerpt:

To provide further operational flexibility, America's Power urges EPA to allow coal plant owners and operators to comply with the annual net generation limitation by averaging the annual generation production levels of multiple generating units under common operation or ownership and located at the same site. Under this approach, the owners and operators of multiple units located at the same plant site would have the option of complying with either the proposed annual net generation limitation on a unit-by-unit basis, or a combined annual net generation limitation applicable to multiple units through an averaging compliance option.[12] The added flexibility provided through averaging among multiple affected units at the same site would promote reliability of the electricity grid by allowing one unit to operate higher than its annual unit-specific generation limitation if one of the other units at the same site is unable to operate due to an extended forced outage or other operational constraints. Furthermore, these operational and reliability advantages will be achieved while still ensuring the same protection of the environment because the cumulative effluent discharges from the entire coal-fired generating facility under the combined generation limitation would be equivalent to the amount of discharges under a unit-by-unit approach.

12 In particular, the owners or operators of multiple units located at the same plant site would have the option of complying with the proposed annual generation limitation of 876,000 MWh on a unit-by-unit basis, or a combined generation limitation of 2,628,000 MWh for a three-unit facility (3 units x 876,000 MWh per unit) that would apply to all three units through the multi-unit compliance option.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 2

Comment Excerpt:

First, GSP Merrimack supports the addition of a subcategory for “low utilization boilers” (“LUBs”) for both FGD wastewater and BA transport water. EPA is correct that cost and energy considerations dictate that such units not be subject to the same technology requirements as other covered units. However, as discussed below, the demonstration for the LUB subcategory should be based on the average of the two-year average net generation <u>of all units at the facility sharing a common treatment system</u>.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 5

Comment Excerpt:

GSP Merrimack supports the addition of a subcategory of “low utilization boilers” (“LUB”) for both FGD wastewater and BA transport water. As explained in the Proposed Rule, EPA is well within its authority to establish subcategories when supported by the record. 84 Fed. Reg. at 64,624. As EPA notes, there have been changes in the electricity generation sector since the 2015 rule was promulgated that necessitate a LUB subcategory. Id. at 64,626. These changes include “availability of abundant and inexpensive natural gas.” Id. These market forces have caused many coal-fired generating units to shift from baseload operation to seasonal or peaking operation and have changed the economic profile of these units. Id. This shift is illustrated by Merrimack Station in New Hampshire. Merrimack Station previously operated as a baseload unit, but in recent years has served as a seasonal and peak demand resource. By way of example, in 2010, the annual capacity factor for Merrimack Station’s Units 1 & 2 (both coal-fired) was

69.4%, but in 2019, it fell to 7.9%. Despite its reduced generation, Merrimack Station plays an important role in providing grid generation diversity, especially during critical winter months when natural gas becomes constrained in ISO-NE. Thus, EPA is correct that the "continued operation [of LUBs] is useful, if not necessary, for ensuring electricity reliability in the near term." Id. at 64,639.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 6

Comment Excerpt:

EPA is correct that these changes in operation at LUBs, and the resulting changes in cost profile, must be accommodated when setting discharge limitations for FGD wastewater and BA transport water for these units. EPA correctly concludes that "the record indicates that disparate costs to meet the proposed FGD wastewater and BA transport water BAT limitations . . . are imposed on boilers with low capacity utilization," id. at 64,638, and, further, that "[a]ttempting to pass on the higher costs per MWh produced would make these boilers increasingly uncompetitive," id. at 64,639. These cost and non-water quality environmental impact (e.g., premature retirement of these LUBs) considerations provide a well-reasoned basis for the creation of this regulatory subcategory. GSP Merrimack agrees with EPA that "[c]hemical precipitation for FGD wastewater and surface impoundments for BA transport water . . . are the only technologies . . . [that] would not impose such disproportionate costs on this subcategory of boilers." Id. EPA is also correct that such cost considerations would impact a Best Professional Judgment ("BPJ") determination for these waste streams. Id.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 7

Comment Excerpt:

EPA should finalize a LUB subcategory but should make certain changes to the proposed LUB provisions for the subcategory to function as intended. First, the generation threshold should be applied as the average of the two-year average net generation from all boilers at the facility sharing a common water treatment system. Because boilers at the same facility often share the same emission control equipment and associated water treatment system (as does Merrimack Station, for example), it would make no sense for these boilers to be subject to different technology requirements where, averaged together, their two-year average net generation is below the threshold. Such a situation would involve the same and likely greater cost disparities that EPA cites as the basis for the LUB subcategory. Under our proposed approach, for example, if, at a two-unit facility, Unit 1's two-year average net generation was 900,000 MWh and Unit 2's two-year average net generation was 800,000 MWh, both units would continue to qualify for the subcategory (because the average of their two-year average net generation would be 850,000 MWh). Such a situation may occur, for example, when one unit experiences an extended outage in a given year. Such an occurrence would not justify subjecting one unit to more stringent technology requirements.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 8

Comment Excerpt:

Second, the LUB provision should not include the "automatic" re-categorization of an LUB during the permit term, as EPA proposes. Id. at 64,666 (proposed § 423.13(g)(2)(iii)(B) & § 423.13(k)(2)(iii)(B)). The current regulations and the Proposed Rule recognize that site-specific information is necessary to determine the "as soon as possible" implementation date for the FGD wastewater and BA transport water limitations applicable to the steam electric generation point source category generally and, further, that this date can be longer than two years. See 40 C.F.R. § 423.11(t); 84 Fed. Reg. at 64,664-65. There is no basis in the record for abandoning this approach with respect to LUBs that no longer qualify for the subcategory because of increased net generation. The same "as soon as possible" factors should instead be considered at the next permit renewal, meaning that proposed § 423.13(g)(2)(iii)(B) & § 423.13(k)(2)(iii)(B) should be deleted and not finalized. At a minimum, if EPA does retain these provisions, they should be revised to allow for three years or longer for the re-categorized facility to meet the more stringent limitations, consistent with the information in the record, which indicates that not all facilities can meet a two year deadline for the new FGD wastewater or BA transport water limitations. 84 Fed. Reg. at 64,665 n.101.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 9

Comment Excerpt:

In addition, EPA correctly explains in the Proposed Rule that subcategorization of low utilization boilers is necessary because of cost and non-water quality impacts unique to these units.[17] While coal units have historically operated as base load units, many of these units today run more intermittently, often due to displacement by other types of generation with lower marginal costs.[18] As a result of this reduced generation, the cost of implementing the technologies necessary to meet the proposed FGD wastewater and bottom ash transport water limitations would be significantly higher for these units than for other units.[19]

As EPA shows in the Proposed Rule, the cost per megawatt hour of implementing these new technologies can range up to nearly $22/MWh for units operating less than 876,000 MWh per year, compared to costs generally below $2/MWh for units operating greater than 876,000 MWh per year.[20] In fact, we would anticipate these costs would be even higher for these units. Imposing additional, disproportionate costs on units that are already economically challenged "would make these boilers increasingly uncompetitive, exacerbating the disparate cost impacts."[21] This could force more coal-fueled units into early retirement, jeopardizing reliability, as noted above. Accordingly, a subcategory for low utilization boilers is necessary.

[18] Id.
[19] Id.
[20] Id. at 64,639, Figure VIII-1.
[21] Id. at 64,639.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 10

Comment Excerpt:

Although Vistra supports EPA's proposal to establish a subcategory for these boilers, Vistra encourages EPA to revise its methodology for determining eligibility with this subcategory to account for multiple boilers that rely on the same water treatment system and boilers co-firing with natural gas. Specifically, under the Proposed Rule, a facility must certify that "the two-year average annual net generation [of a relevant boiler] is below 876,000 MWh per year" in order for a boiler to qualify for the low utilization subcategory.[22] However, EPA should revise this provision to encompass multiple boilers at the same facility whose combined two-year average annual net generation is below 876,000 MWh per year. In practice, multiple boilers at a single facility often rely on common systems, such as a single water treatment system. If one boiler at the facility has a two-year average annual net generation slightly above the 876,000 MWh per year limit while the other boiler is below that limit, the approach in the Proposed Rule would subject both boilers to the costly technology requirement as a practical matter, even if the combined two-year average annual net generation was below 876,000 MWh per year.[23] EPA's rationale for its low utilization boiler subcategory should be logically extended to account for facilities with more than one unit served by the same wastewater treatment system that have a combined two-year average net annual generation below 876,000 MWh per year.

[22] Id. at 64,672 (proposed 40 C.F.R. § 423.11(z)).
[23] That is, if one unit at the facility had a two-year average annual net generation of 950,000 MWh per year while the other unit had a two year average of 700,000 MWh, their combined average would be 825,000 MWh. Nonetheless, the facility would be required to comply with the more stringent technology requirements as a result of the first unit's generation of 950,000 MWh.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 11

Comment Excerpt:

Additionally, EPA should revise its eligibility provision for low utilization boilers to only consider generation from coal for the purpose of the 876,000 MWh threshold. Many coal-fueled boilers also have the ability to co-fire natural gas; however, operation of a boiler on natural gas does not create the same waste streams (i.e., FGD wastewater and bottom ash transport water) that are at issue here. Therefore, EPA should limit a facility's calculation of annual net generation for the purpose of the 876,000 MWh threshold to only include net generation from coal—the fuel that forms that basis for these standards. Such an approach will prevent any unnecessary disincentives to co-firing on natural gas when appropriate without any impact to the regulated waste streams.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 14

Comment Excerpt:

The Final Rule Should Include a Workable Low Utilization Boiler Subcategory.

Talen generally supports a proposed low utilization boiler subcategory. This subcategorization will increase the resiliency of the power grid by permitting some coal-fired units that supply essential peaking or cycling power to continue to operate, while capping their net generation and therefore limiting pollutant discharges. These units will function primarily during emergencies or extreme weather periods when the grid needs maximum capacity. Without this subcategorization, many of the low utilization boilers will be very marginal from an economic standpoint and high costs per megawatt hour (MWh) may force more unit closures and impact grid reliability.

Talen believes EPA has appropriately justified at the least its proposed 876,000 MWhs threshold for defining low utilization boilers, but Talen does agree with the modification UWAG is proposing to further expand this subcategory as noted below:

Within the Low Utilization Subcategory, EPA should provide as follows:

- Units certified to operate below 438,000 MWhs (as a two-year average net generation) should not be subject to the proposed arsenic and mercury limits or BATW requirements. These units would be subject to TSS limits consistent with BPT.
- Similarly, units that certify to (1) operate below the 876,000 MWhs as a two-year average net generation, and (2) retire or repower by December 31, 2031 also should not be subject to the proposed arsenic and mercury limits or BATW requirements but would be subject to TSS limits consistent with BPT.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 15

Comment Excerpt:

Talen also recommends that EPA clearly indicate that when demonstrating a unit's qualification as a low utilization boiler only the generation resulting from coal firing operation be included. This is specifically important to dual fuel-fired units such as the three boilers at Talen's Brunner Island facility that can fire on either coal or natural gas.

The data to show when such dual fuel-fired boilers are operated on only gas are available. Specifically, the gross hourly fuel use data is available in EPA's Clean Air Markets Database (CAMD) for all dual-fueled units, and such facilities can take those gross generation numbers and calculate a net generation attributable solely to coal. As a part of the proposed required annual certification, dual-fueled units could report their total net generation from EIA and then calculate the coal-fired net generation based on the 40 CFR Part 75 regulatory quarterly reporting (found in CAMD) and report that value as a part of the facility's certification for that generating unit.

When a dual-fueled unit is only operated on natural gas it is not producing FGD wastewaters or BATW as it would if it was firing on coal. Therefore, the basis for certifying for a low utilization boiler should be based only on MWhrs when firing on coal.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 106

Comment Excerpt:

D. The Proposed Subcategory for "Low Utilization" Units is Unjustified.

1. EPA lacks the legal authority to create a subcategory based exclusively on compliance costs.

To the extent that EPA has any authority to create subcategories, it must consider all of the statutory BAT factors and cannot base its decision on any one factor in isolation.[365] Yet, the record shows that EPA impermissibly based its decision to create the “low utilization” subcategory exclusively on cost.

Although EPA claims that the new low-utilization subcategory was created “based on the statutory factors of cost and non-water quality environmental impacts,” the sum total of EPA’s evaluation of “non-water quality environmental impacts” is as follows: “[T]he EPA considered non-water quality environmental impacts (including energy requirements). Low utilization boilers tend to operate only during peak loading. Thus, their continued operation is useful, if not necessary, for ensuring electricity reliability in the near term.”[366]

EPA provides nothing more than two sentences of speculation, unsupported by any data. Nothing in the record suggests that the units in the proposed low-utilization subcategory are necessary for ensuring reliability. In fact, many of them are not peaking units at all: As discussed in more detail below in Section X.E – Reliability, many of the units in the proposed subcategory run at relatively high utilization rates, and many smaller units could run at 100% capacity and still qualify for the subcategory.

In addition, a cursory review of the record fails to show any meaningful difference in unit retirements between Option 2 (which includes the low-utilization subcategory) and Option 4 (which does not). As EPA acknowledges, the fate of the coal industry is largely being driven by factors other than environmental regulations.[367] EPA estimates that national coal capacity under the baseline scenario will decline by 32 GW, or 18%, between 2021 and 2050.[368] The changes associated with Options 2 and 4, by contrast, are minimal – by 2050, national coal capacity under either option is projected to differ from capacity under baseline by less than 1 GW.[369] In other words, the choice of regulatory option has virtually no impact on trends in coal capacity, which are being driven by other factors. The differences between Options 2 and 4 are even smaller. In fact, EPA projects that coal capacity under Option 4 (without the low-utilization subcategory) will be higher than under Option 2.[370] There is simply no basis in the record for EPA’s off-hand speculation about reliability.

Moreover, there are many “non-water quality environmental impacts” that EPA simply failed to consider, most notably the effects of carbon emissions. If EPA truly believes that the ELG rule would force some of the so-called low-utilization units to retire, then the Agency should balance any purported reliability impacts caused by those retirements (to be clear, the record shows no such impacts – see Section X.E – Reliability) against the corresponding reductions in carbon emissions. Yet, EPA is silent about any “non-water quality environmental impacts” other than electricity reliability.

EPA’s speculation about reliability contradicts the record and is unsupported by any evidence, so the Agency cannot claim to have considered electricity reliability in any meaningful way. And EPA did not even mention any other “non-water quality environmental impacts.” In sum, the Agency did not actually consider the “non-water quality environmental impacts” factor at all.

Nor did EPA consider any of the other statutory factors. EPA makes no mention of whether the "low-utilization" units differ in terms of the "age of equipment and facilities involved," the "process employed," the "engineering aspects . . . of control techniques," or any "process changes."[371] Indeed, the available evidence in the record indicates that the "low-utilization" units are similar to the rest of the industry with respect to these factors, which further undermines EPA's arbitrary subcategorization. The CWA requires that "similar point sources with similar characteristics . . . meet similar effluent limitations."[372] EPA has not shown, through an evaluation of all statutory BAT factors, that the so-called "low-utilization" plants are dissimilar. It is very unlikely that EPA could make such a showing even if it tried. Because these units are in fact "similar point sources" and must "meet similar effluent limitations," the proposed subcategory is unlawful.

[365] See Section X.A - Legal Authority for Subcategorization; *Chem Mfrs. Ass'n v. Nat. Res. Def. Council, Inc.,* 470 U.S. 116, 130-31 (1985); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 214-15 (5th Cir. 1989); *Tex. Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 934 (5th Cir. 1998).
[366] 84 Fed. Reg. at 64,639.
[367] Proposed RIA at 2-9 to 2-10.
[368] Proposed RIA at 5-6, Tbl. 5-2.
[369] Proposed RIA at 5-7, Tbl. 5-3.
[370] Id.
[371] 33 U.S.C. § 1314(b)(2)(B).
[372] *Chem Mfrs. Ass'n v. Nat. Res. Def. Council, Inc*., 470 U.S. 116, 130 (1985) (quoting S. Rep. No. 92-1236, at 126 (1972)).

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 2

Comment Excerpt:

We urge EPA to establish a multi-unit averaging procedure for meeting the annual net generation limitation for being classified as a low-utilization unit. As discussed below, allowing multi-unit averaging for low-utilization units will lower operational
costs and promote electric grid reliability. Furthermore, it will achieve these important policy objectives while also ensuring the protection of the environment given that the total amount of cumulative effluent discharges from the entire facility under the combined generation limitation are equivalent to the amount of discharges under a unit-by-unit approach. Similarly, the establishment of a new source subcategory for retiring coal-fired EGUs is needed to avoid stranded costs and unacceptable disproportionately high compliance costs for some retiring units that may shut down after 2028. To improve the effectiveness and workability of EPA's proposal, the Corporation recommends that EPA also create another new source subcategory that would extend resources. The details of these suggested improvements to the Proposed Rule are discussed in greater detail in the comments below.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 6

Comment Excerpt:

A. A Multi-Unit Averaging Compliance Option Should Be Provided For Low Utilization Boilers In Order To Lower Operational Costs And Promote Electric Grid Reliability.

EPA proposes to establish a new source subcategory for low utilization boilers. A low utilization boiler is defined in the Proposed Rule as a boiler with a two-year average annual net generation that is below 876,000 MWh per year (equivalent to a 400 MW coal-fired boiler operating at a 25 percent capacity factor). The establishment of this subcategory makes sense given that many existing coal-fired EGUs were operated at one time as baseload generating facilities, but are now dispatched as load-following units or even just operate for short durations to meet peak demands in the summer or winter. Furthermore, we agree with EPA's proposal to use a two-year average when setting the annual generation limitation of 876,000 MWh per year. The use of a two-year average will help to smooth out any sudden unplanned increases in a unit's annual generation levels due to unforeseen circumstances, such as extreme weather events or forced outages of other generating units with an electricity utility system.

To provide further operational flexibility, Oglethorpe Power recommends that EPA not impose the annual net generation limitation only on a boiler-by-boiler basis. Rather, the Agency should allow an EGU owner or operator to comply with the annual generation limitation by averaging the annual generation production levels of multiple EGUs. In particular, such averaging should be allowed among affected generating units under common operation or ownership that are located at the same EGU facility site. If, for example, three units are located at one generating facility, the owner or operator of those units would have the option of electing to comply either with the proposed annual generation limitation of 876,000 MWh on a unit-by-unit basis, or a combined generation limitation of 2,628,000 MWh (3 x 876,000 MWh) that would apply to all three units through the multi-unit averaging compliance option.

The added flexibility provided through averaging among multiple affected units will lower operational costs and promote reliability of the electricity grid, while still ensuring the protection of the environment. The flexibility to average among units lowers operational costs by providing increased operational flexibility and economic dispatch. For example, the multi-unit averaging compliance option allows EGU owners and operators to dispatch lower-cost units at higher utilization levels than the higher-cost units over the annual compliance period so long as the combined annual generation limitation of 2,628,000 MWh is not exceeded for all units at the facility. Similarly, this operational flexibility will help to ensure electric grid reliability by allowing one unit to operate higher than its annual unit-specific generation limitation of 876,000 MWh if one of the other units at the same facility is unable to operate due to an extended forced outage or other operational constraint. Finally, such an averaging provision will provide these important operational and reliability benefits while still ensuring the protection of the environment given the total amount of cumulative effluent discharges from the entire facility under the combined generation limitation are equivalent to the amount of discharges under a unit-by-unit approach.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 7

Comment Excerpt:

B. Clarification Is Needed On The Timeframe For Making An Election To Establish An Annual Generation Limitation For Low-Utilization Units.
Oglethorpe Power also has a technical concern regarding the process proposed for electing to apply the annual generation limitation under the low-utilization subcategory. The Proposed Rule requires the owner or operator to submit an initial certification statement that provides the calculation of the two-year average net generation limitation for each applicable boiler, along with the required underlying information in support for that calculation. This submission requirement, however, is unclear and needs clarification with respect to the timing and process for making the submission. In particular, the regulatory text in the Proposed Rule only states that "an initial certification shall be made to the permitting authority with a permit application."[4] It does not specify any minimum date by when the submission must be made. Nor does it address those situations (which will frequently occur) when permit applications are currently pending or the permitting authority has recently issued a National Pollutant Discharge Elimination System ("NPDES") permit for the boiler and the submission of a new permit application may not be necessary for another four or five years.

To clarify submission requirements for these situations, the Corporation recommends that EPA revise proposed section 423.19(e)(1) to require that the initial certification statement be submitted to the permitting authority by a date certain, specifically within three years from the promulgation date of the final ELG rule in the Federal Register.

4 84 Fed. Reg. at 64,677 (citing proposed 40 C.F.R. §423.19(e)(1)).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 49

Comment Excerpt:

V. CARVE-OUTS

a. Characteristics of the Southeastern Power Sector Undermine Reliability Concerns

EPA cites the need to maintain electric system reliability as basis for carving out subcategories for low utilization boilers and boilers retiring by 2028. Yet, as fully explained in the comments submitted on our behalf by Earthjustice, the Agency fails to provide a reasonable link between a hypothetical impact on the electric grid and the potential decision by the owners of those boilers to retire them rather than invest in the measures necessary to comply with the ELGs. EPA's rationale lacks merit when compared with the reality of the power sector in the Southeast.

First, the Southeast is awash in excess generating capacity. Of the six states covered by SELC, within the North American Electric Reliability Corporation framework, all or most of five are covered by the SERC region and one falls within PJM. The four SERC sub-regions have anticipated 2024 reserve margins of between 25 and 36% (representing a cumulative expected capacity surplus of nearly 25 GW, against the reference margin level, or target reserve margin, needed for reliability in this region of 15%. Similarly, PJM has an anticipated 2024 reserve margin of 34% (an expected capacity surplus of nearly 27 GW), more than double the target reserve margin of 15.7%. For the South, the existence of so much surplus generating capacity undercuts EPA's facile conclusion that the loss of the boilers in these subcategories would rob the grid of much needed generating capacity.

Second, the vast majority of coal-fired power plants in our region are owned and operated by either vertically integrated investor-owned utilities, such as Dominion Energy, Duke Energy, and Georgia Power, or public power utilities such as Tennessee Valley Authority and Santee Cooper. Both types of entities develop long-range energy plans based on least-cost planning principles, which includes factoring in the range of anticipated costs of different energy resource types. These costs can vary depending on many inputs, such as possible regulatory requirements for environmental compliance. For the investor-owned utilities, their long-term plans must be approved in integrated resource planning proceedings conducted by the state commissions which oversee their business decisions. For instance, Virginia law requires that an IRP "systematically evaluate . . . [t]he effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities" and "[t]he most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations."[122] By virtue of these and other similar requirements, the owners of coal-fired boilers in the Southeast are and have been under the obligation, in many instances backed by the force of state law, to acknowledge and plan for the possibility that the environmental and public health safeguards implemented by the ELGs could compel retirement of some coal capacity. EPA offers no explanation for why these requirements have not already had their intended effect of preparing the utilities for this potential result of the ELGs and why therefore it must be a federal environmental agency that steps in to relieve the utilities of their legal obligation.

Third, a shift away from coal-fired generation is well underway, driven by market forces. The vacuum left by the gradual disappearance of coal in the Southeast's generation fleet has primarily been filled by natural gas generation, which has seen its fuel cost reduced by newly available supplies of gas. And even clean alternatives, chiefly solar power, are cheaper than continuing to run coal plants. One recent report conservatively compared the current (2017) marginal cost of energy for operating coal-fired power plants across the country to the levelized cost of energy for new wind and solar power localized around each coal plant. In discussing their findings, the authors noted that new solar out-competes existing coal: "[I]t is hard to imagine Southeastern utilities not relying heavily on solar and complementary load shifting resources to replace the coal and save customers money."[123] Thus, even absent the additional investments required to comply with the ELGs, economic pressures outside of EPA's purview are compelling utilities to close their coal-fired operations, undercutting the Agency's claim that allowing some of these units a carve-out from the ELG safeguards would prevent the broad and inexorable retirement of coal in the region, and any associated reliability implications for the electric grid.[124]

[122] Va. Code § 56-599 B 8 & B 9. See also, e.g., NCUC Rule R8-60(g) (in an IRP, each utility "shall analyze … significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation"); SC Code 58-37-40 (B)(1)(e)(iii)) (IRPs must include consideration of "sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks").
[123] Eric Gimon, et al., The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources (March 2019), available at https://energyinnovation.org/publication/the-coal-cost-crossover/, at 10 (Attachment 115).
[124] See also letter from Southern Environmental Law Center to EPA, 18-22 (Oct. 31, 2018) (Attachment 116).

Commenter Name: Megan Kimball
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Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 57

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Moreover, the agency's analysis of cost is incompatible with the BAT standard. The cost of a given technology is relevant only as to whether it "can be reasonably borne ***by the industry***," not an individual unit.[149] Yet EPA purports to evaluate the cost of imposing treatment requirements in terms of the economic competitiveness of an individual boiler.[150] That is not a valid approach to BAT.

Because BAT requires consideration of whether cost is economically achievable for the industry as a whole, it does not authorize EPA to weigh the cost of implementation for certain boilers against others and deem them "disproportionate," as it has done here.[151] These are "lowutilization" boilers because the industry has determined that it is more economical to use others to meet demand, but that is not a reason to exempt the industry from complying with required pollution controls at these facilities. The cost per megawatt for an individual boiler is irrelevant to the BAT inquiry.

[149] *Chem. Mfrs. Ass'n*, 870 F.2d at 262 (emphasis added).
[150] 84 Fed. Reg. at 64,639.
[151] Id.

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Comment Excerpt Number: 58

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EPA's analysis is also faulty because many plants with a low-utilization boiler likely will need to upgrade their treatment systems for their other boilers. For example, Duke Energy's Roxboro plant in Semora, NC, has one unit likely to qualify as low-utilization. But the facility has had to install a bioreactor to deal with its significant selenium pollution of Hyco Lake, and this bioreactor treats FGD wastewater from both power generating units at the plant.[152] Thus, the costs of treatment have been incurred—as they would be at most, if not all, facilities—and are recovered through the rates charged for power generated by all units at the facility, making EPA's per-unit economic analysis even more baseless. Exempting generating units under these circumstances is unjustified: a facility that must treat its wastewater from other units should combine its wastewater flows from low-utilization units through that treatment system.

EPA also claims that "energy requirements" justify its proposed carveout, asserting that these units' continued operation "is useful, if not necessary, for ensuring electricity reliability in the near term."[153] But this argument lacks merit, as explained above. Moreover, if EPA were to look seriously at using its regulation to attempt to prolong the life of these coal-fired generating units, it would need to take into account their air emissions, including greenhouse gas emissions, from their operation as well as the environmental impacts of mining and transporting coal to these facilities. But EPA appears not to have done any such thing.

[152] NC DEQ, Fact Sheet for NPDES Permit Development, NPDES # NC0003425 (Roxboro) (Jan. 5, 2017) (Attachment 53).
[153] 84 Fed. Reg. at 64,639.

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Document Control Number: EPA-HQ-OW-2009-0819-8323-A1
Comment Excerpt Number: 7

Comment Excerpt:

C. EPA's Proposed Subcategorization of Low-Utilization Boilers Is Arbitrary and Capricious.

EPA should not create a more lenient subcategory for boilers with "low utilization," either. See 84 Fed. Reg. at 64,638-39. Once again, EPA's principal reason for proposing this subcategory is cost: according to EPA, the more stringent standards will impose "disparate costs" on low-utilization boilers and, if the costs are passed on, “would make these boilers increasingly uncompetitive.” Id. Once again, that reason is inadequate. Even if EPA is correct that the more stringent standards would be more costly (per MWh) for these boilers than for others, the proposal does not explain why those costs are so excessive as to warrant an exception resulting in increased water pollution. And although EPA asserts that low-utilization boilers’ “continued operation is useful, if not necessary, for ensuring electricity reliability in the near term,” id. at 64,639, it provides no reason to conclude that adhering to more stringent standards will actually hinder those boilers’ continued operation.

As with the proposed subcategory for boilers retiring by 2028, moreover, the subcategory for low-utilization boilers appears ripe for improper exploitation. For one thing, eligibility for this subcategory is to be calculated on a two-year average basis—enabling a boiler to significantly exceed the eligibility threshold in one year as long as it correspondingly reduces utilization in the prior and subsequent years. Id. at 64,665. For another thing, once a boiler qualifies for (and benefits from) subcategorization as low-utilization, it still can ramp back up—in which case it will have another two years to come into compliance with the limitations applicable to the rest of the point source category. Id. And if the owner can cast the boiler’s newly increased utilization as the result of “involuntary orders and agreements,” the boiler apparently can continue to benefit from the less stringent limitations applicable to the low-utilization subcategory. Id. at 64,666. These loopholes are significant and render the proposed subcategory arbitrary and capricious.

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Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 9

Comment Excerpt:

Similarly, in establishing the subcategory for low utilization plants, EPA endorses laxer standards by explaining that many coal plants do not operate at full capacity because of low natural gas prices, and that meeting the 2015 limitations would make such plants “increasingly uncompetitive.”[63] The agency further considers the effect of laxer standards on energy requirements, and asserts that continued operation of low utilization boilers would be “useful, if not necessary.”[64] However, EPA nowhere accounts for the environmental harm that the continued operation of such plants might cause—from a water pollution perspective, an air pollution perspective, or a climate change perspective.

Nor does the agency account for the possibility of inaccurate reporting by power plants that operate beyond their reported levels and thus pollute at higher levels. The low utilization boiler subcategory is explicitly conditioned not on a boiler’s capacity, but rather on a boiler’s utilization, averaged over two years.[65] To get utilization information, EPA must rely on reporting by facilities.[66] This could lead to additional health and environmental harms for a couple of reasons. First, some facilities might understate boiler utilization to qualify for this subcategory. If boilers receiving the subcategory's laxer standards are actually used more than the regulatory cut-off, then the resulting pollution will also be greater than the regulation predicts, assuming 100% accurate reporting. Second, as EPA acknowledges in another context,[67] boiler use can change suddenly, so a boiler with a low average rate for two years might have a higher use rate in the third year. The subcategory is structured in a way that allows such a boiler to operate at the higher utilization rate while taking advantage of laxer standards theoretically reserved for low utilization plants.[68] Because the boiler must report its utilization only annually, and must then report only two year averages, a boiler in the low utilization subcategory that is actually used at a high rate would be able to exploit laxer standards for at least a year, if not longer. EPA should take these possibilities into account in selecting the BAT and address the likely effects on health and the environment.

In sum, EPA should consider and communicate the expected health and environmental effects of setting a laxer subcategory for low utilization boilers. Furthermore, that analysis should take into account the possibility of inaccurate or unrepresentative reporting upon which the subcategory depends. Again, the agency violates its statutory obligation to consider whether its proposed BAT for low utilization boilers is truly "best" at making progress toward eliminating the discharge of all pollutants, or whether the BAT has an unacceptable "non-water quality environmental impact."

63 Proposed Rule, 84 Fed. Reg. at 64,638–39.
64 Id. at 64,639.
65 See id. at 64,665–66 (discussing how facilities qualify for and maintain subcategory status).
66 Id.
67 See id. (finding a two-year average necessary because a shorter average might be skewed by "a single extreme demand event in one year").
68 See id. at 64,666 (requiring the facility to report updated two-year averages annually, allowing plants to operate for a year at a higher utilization rate).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 109

Comment Excerpt:

2. 'Disparate costs' are not a legitimate justification for a subcategory

Not only did EPA fail to consider any statutory factors other than cost, it also failed to evaluate cost correctly. EPA argues that the so-called "low-utilization" plants will face "disparate costs" and will be at a competitive disadvantage unless the Agency grants them an exemption from the BAT limits that apply to the rest of the industry. EPA has not demonstrated that this is true, but, in any case, EPA is not authorized to create subcategories for the purpose of preventing a competitive disadvantage. As explained above, "the [CWA]'s supporters in both Houses acknowledged and accepted the possibility that its 1977 requirements might cause individual plants to go out of business,"[373] and "Congress clearly understood that achieving the CWA's goal of eliminating all discharges would cause . . . plant closures."[374]

Inevitably, some plants will have higher compliance costs than other plants. A creative data analyst could probably carve out dozens of subcategories with higher costs than the rest of the industry. But that would be an irrelevant and arbitrary exercise that is antithetical to the CWA's requirements. It is not EPA's job to make sure that its regulations are convenient. EPA's job is to ensure that polluters commit the "maximum resources economically possible to the ultimate goal of eliminating all polluting discharges."[375]

EPA's statutory authority for considering cost is narrow. An available technology is BAT if it is also "economically achievable," and a technology is "economically achievable" if the "costs can be reasonably borne by the industry [or, in this case, the subcategory]."[376] Compliance costs can be higher for a subcategory and still be reasonable for that subcategory. EPA has not shown, or even tried to show, that the costs of complying with the default BAT standard cannot be reasonably borne by the low-utilization plants. If the costs can be reasonably borne by the low-utilization plants, then there is simply no basis for the subcategory.

[373] *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1036-37 (D.C. Cir. 1978).
[374] *Chem Mfrs. Ass'n*, 870 F.2d at 251.
[375] *EPA v. Nat'l Crushed Stone Ass'n,* 449 U.S. 64, 74 (1980).
[376] *Waterkeeper All., Inc. v. EPA*, 399 F.3d at 516; Rybachek v. EPA, 904 F.2d 1276, 1290-91 (9th Cir. 1990) (discussing this standard).

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 110

Comment Excerpt:

3. EPA's definition of the low-utilization subcategory is arbitrary; a fair assessment of the record fails to support the need for the subcategory

Even if EPA had authority to create a subcategory based on cost (it does not), the record shows that there is no cost-based justification for a low-utilization subcategory. The Agency's arguments to the contrary fall apart under the most cursory level of scrutiny. The holes in EPA's logic become evident when one looks at how the Agency defines the proposed subcategory. A more objective and careful appraisal of the evidence shows that power plants that run less often do not face higher costs than other power plants.

EPA creates a "low utilization" subcategory defined by unit-level utilization in Megawatt hours (MWh) per year. This is arbitrary and irrational in several ways:

- First, it assumes that unit-level characteristics, rather than plant-level characteristics, are an appropriate unit of comparison;

- Second, it fails to distinguish between bottom ash costs and FGD costs, even though there is no reason to believe that the relationship between cost and utilization (or some other metric) would be the same for both wastestreams;
- Third, it defines "low utilization" in a way that will include many high-utilization units and also exclude many low-utilization units;
- Fourth, it assumes that utilization is an appropriate unit of comparison and fails to consider capacity factor;
- Finally, it uses a different baseline than it uses elsewhere in the rulemaking record.

Each of these flaws is discussed in more detail below. A more careful analysis of the data in the record shows that there is simply no legitimate or practical basis for a low-utilization threshold.

To begin with, EPA fails to explain why unit-level generation is relevant when power plants with multiple units benefit from economies of scale and can treat wastewater at lower per-unit cost. For example, the Kingston Fossil Plant has nine generating units, and each unit generates less than 876,000 MWh per year. As a result, the entire power plant qualifies for the low-utilization subcategory, despite the fact that the plant as a whole generates over 5,000,000 MWh per year. This is plainly irrational. Common sense indicates that the Tennessee Valley Authority could treat the FGD wastewater at Kingston with a single treatment system, and the costs would be much lower than the costs for nine separate single-unit power plants. And indeed, EPA's primary cost calculations are at the plant level: Page 5-59 of the Supplemental Technical Development Document explains that "[t]o estimate total industry compliance costs for each regulatory option with subcategories, the EPA first estimated plant-level FGD and bottom ash technology option compliance costs."[377] EPA then apportioned these plant-level costs to the unit level according to each unit's capacity.[378] If costs are incurred at the plant level, with potential economies of scale for multi-unit plants, then it is arbitrary and capricious for EPA to analyze unit-level cost impacts for purposes of subcategorization.

The second problem with EPA's analysis is that the Agency combines treatment costs for FGD wastewater and bottom ash transport water into a single simplistic analysis of per-MWh costs. This ignores the very real possibility that the relationship between cost and generation is different for the two treatment technologies.

We aggregated generation and annualized[379] compliance costs at the plant level, keeping the two wastestreams separate, and plotted per-MWh compliance costs for Option 4 in Figures LU1 and LU2 below. Similar figures using Option 3 costs would be substantially the same.[380] These figures show three things. First of all, contrary to EPA's depiction in Figure VIII-1 of the 2019 Proposal, there are very few plants that appear to fall into a low-generation cluster with higher per-MWh costs. This is particularly true for FGD wastewater, where there are at most two plants that fall outside the main group of plants. This shows that EPA is effectively creating a plant-level exemption, which is something that it is legally prohibited from doing.[381]

Next, for these plants, there is no evidence that the costs are "disparate,"[382] much less "unreasonable." To be "disparate," the costs would have to be more than just relatively high or above-average. The word disparate is defined as "utterly different in kind, incommensurable."[383] This hardly describes the costs for low-generation plants shown in Figures LU1 and LU2 below;

for each wastestream, only a small handful of plants have per-MWh costs that are more than three times higher than average.[384] More importantly, there is no evidence to suggest that these costs could not be "reasonably borne" by the plants in question.[385] To the contrary, the record shows that the costs can be reasonably borne – there is no meaningful difference in costs as function of revenue between Option 2 (with the proposed low-utilization subcategory) or Option 4 (without): 108 plants incur non-zero compliance costs under either option.[386] There are very few plants that incur costs greater than 3% of revenue under any option; under Option 2, there are 2 such plants, while under Option 4 there are 5 such plants.[387]

Figures LU1 and LU2 also show that the cost-MWh relationship is not the same for the two wastestreams. For bottom ash transport water, there is some evidence that per-MWh costs are higher at lower levels of generation (even if they never rise to the level of "disparate"). For FGD wastewater, on the other hand, there is no such evidence. Two of the low-generating plants have above-average costs, but another two low-generating plants have very low costs (in fact, zero cost). Overall, the costs are largely unrelated to generation.

Figure LU1. Per-MWh compliance costs for bottom ash transport water under Option 4, plotted against generation.[388]

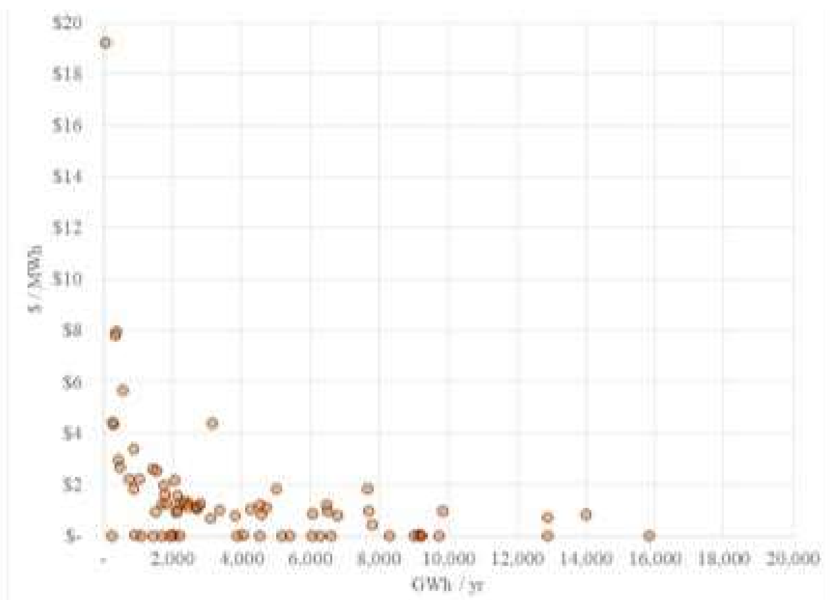
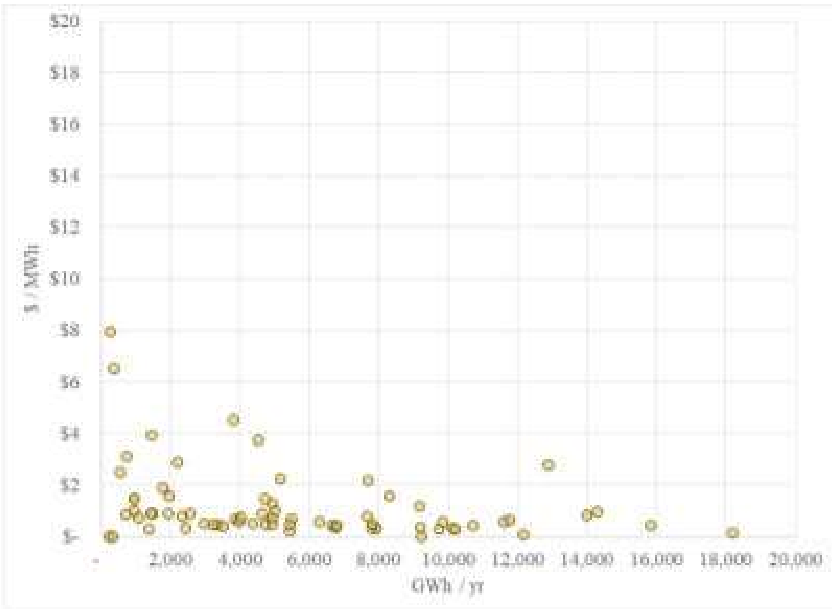


Figure LU2. Per-MWh compliance costs for FGD wastewater under Option 4, plotted against generation.



A third, glaring problem with EPA's analysis is that the proposed subcategory is not what it claims to be. EPA's definition of the subcategory includes any unit generating less than 876,000 MWh per year. This definition could include many units that are "utilized" close to 100% of the time. Specifically, any unit with a capacity of 100 MW or less will automatically be included, regardless of how often the unit runs, because its maximum output will be less than 876,000 MWh. For example, Hennepin Power Station Unit 1 is a 75-MW unit.[389] It runs most of the time (57% of capacity),[390] but it would qualify as a "low-utilization" unit. The same problem affects larger units as well. For example, Shawnee Fossil Plant units 2, 3, 5 and 6 are all 175-MW units, and they each run at 53-56% of capacity.[391] Despite the fact that these units are running more than half of the time, EPA would categorize them as "low-utilization" based on their output.

It is arbitrary and irrational for EPA to define "low utilization" in a way that includes units running most of the time, including (at least theoretically) up to 100% of the time. This is particularly true where the Agency's purported rationale is based not on output but on capacity factor. EPA claims that it needs the low-utilization subcategory to prevent "disparate costs" for certain units. The units that EPA appears to be concerned about include "cycling or peaking boilers" and "larger units that have continued to reduce electricity generation due to market forces (e.g., a 400 MW boiler running at 25% capacity)"[392] – in other words, units with low capacity factors. EPA makes this explicit when it states that "[l]ow utilization boilers tend to operate only during peak loading."[393] Yet, EPA defines the subcategory based on net electricity generation, arbitrarily selecting a characteristic that is only incidentally related to utilization rate.

This flawed logic cuts both ways. EPA's "low-utilization" definition also excludes many truly low-utilization units. For example, the two units at the Victor J. Daniel Jr. plant run at 21-22% capacity; yet, because they are large units (548 MW each), they each generate over one million MWh per year.[394]

In short, EPA's definition of "low utilization" is not actually defined by utilization rate. It includes many "high-utilization" units (units that are utilized most of the time) and excludes many "low-utilization" units (units that are rarely utilized) and, therefore, fails to hold up to the most basic level of scrutiny. Because the definition of the subcategory does not accomplish EPA's purported aims in establishing the subcategory, it is arbitrary and capricious for that reason as well.

This leads to the fourth problem with EPA's analysis, which is that EPA fails to explain why generation levels are a necessary or useful basis for a subcategory. The rule already has a subcategory that relaxes the limits on small units (below 50 MW). The new low-utilization subcategory would include an overlapping subset of the industry by virtue of the fact that smaller units are more likely to generate less than 876,000 MWh per year. In fact, since a 50-MW unit can only generate a maximum of 438,000 MWh per year, all low-capacity units will also be low-utilization units.

EPA also fails to explain why it did not evaluate compliance costs on the basis of capacity factor rather than raw generation. Again, the purported source of EPA's concern is that certain units will have disproportionate costs, with those units being cycling or peaking boilers and larger ones that are generating fewer and fewer MWh per year.[395] In that case, EPA should have evaluated the compliance costs sorted by capacity factor. We do that in Figures LU3 and LU4 below.[396] These figures show that, aside from at most three plants' bottom ash compliance costs, there is no relationship, or at most a very weak relationship, between per-MWh costs and capacity factor. In other words, plants that run less often do not have significantly higher per-MWh costs than plants that run more often.[397] EPA's concerns about power plants that operate at low capacity factors (e.g., peaking and cycling boilers) and about "ensuring electricity reliability"[398] are simply unfounded and not at all supported by the record.

Figure LU3. Per-MWh compliance costs for bottom ash transport water under Option 4, plotted against capacity factor.[399]

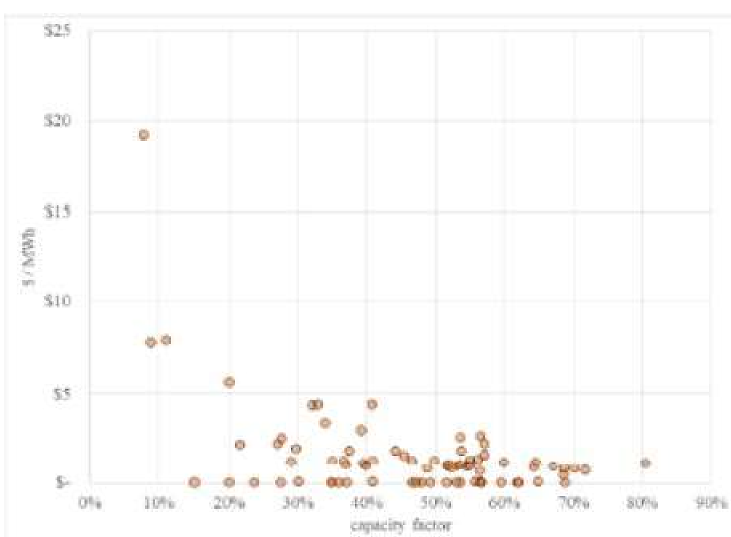
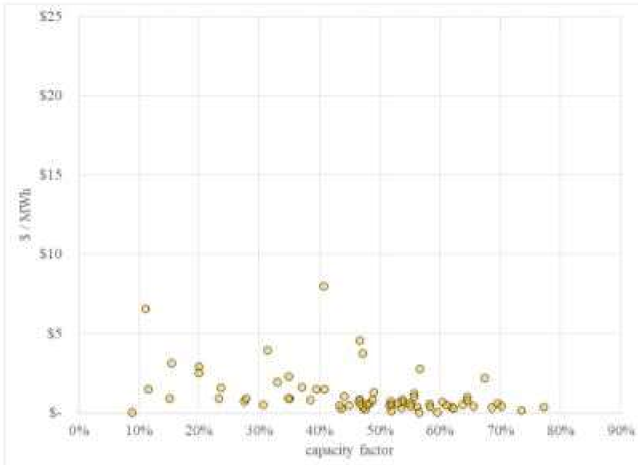


Figure LU4. Per-MWh compliance costs for FGD wastewater under Option 4, plotted against capacity factor.



The fifth problem with EPA's low-utilization analysis is that it arbitrarily uses a different baseline than elsewhere in the record. Virtually all of the analyses in the record, including the analyses in the Technical Development Document and the Benefit Cost Analysis, use a baseline defined by assuming compliance with the 2015 ELG Rule.[400] Against this baseline, EPA finds that all regulatory options reduce costs (which is not surprising given the various loopholes and subcategories that water down EPA's prior BAT determinations).[401] Yet, for purposes of justifying a low-utilization subcategory, EPA decided to evaluate costs relative to a baseline defined by current conditions.[402] Against this baseline, all regulatory options come with an additional compliance cost.[403] This results in EPA's saying two contradictory things: The compliance costs of the rule are negative (cost savings) and the costs are positive. Of course, both cannot be true simultaneously. EPA cannot cherry-pick its baseline to justify a poor decision.

If EPA were to evaluate per-MWh costs using the same baseline that it uses elsewhere, compliance with the 2015 ELG Rule, then it would have to conclude that the so-called "low-utilization" units do not face disparate costs and, if anything, enjoy a relatively greater benefit in the form of compliance cost savings, as Figures LU5 and LU6 below illustrate.[404] For bottom ash treatment, the entire industry would save money (relative to the 2015 Rule), and low-utilization plants would actually save more money than other plants. For FGD costs, some plants would see a cost increase while others would see a cost savings, but there is no relationship between the cost impact and generation.

Figure LU5. Per-MWh compliance costs for bottom ash transport water under Option 4, using compliance with 2015 rule as a baseline.[405]

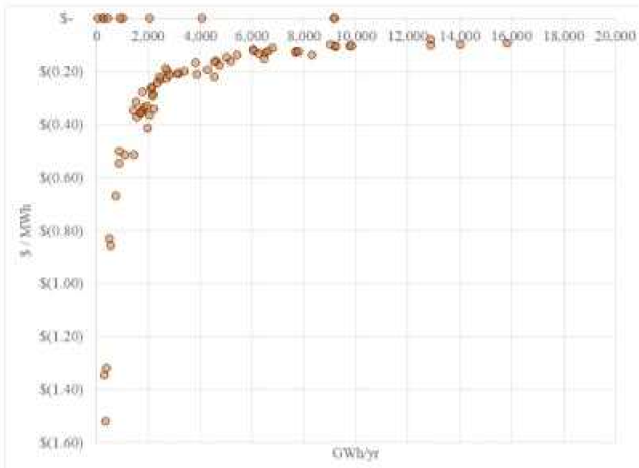
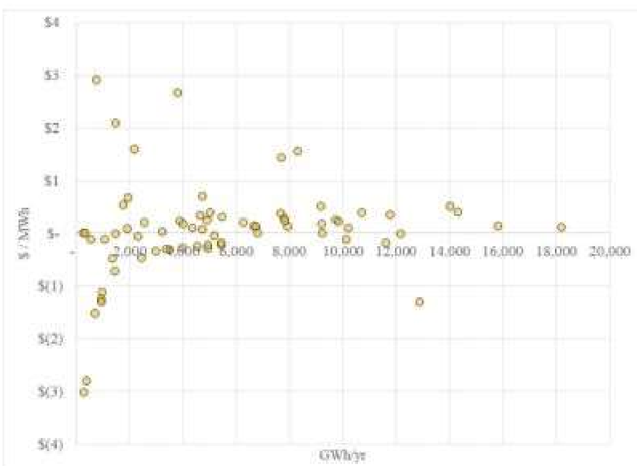


Figure LU6. Per-MWh compliance costs for FGD wastewater under Option 4, using compliance with 2015 rule as a baseline.



Figures LU5 and LU6 show that if EPA used the same baseline it used elsewhere in the rulemaking record, it would have to conclude that the "low-utilization" units are better off than other units, even under Option 4. This directly contradicts EPA's suggestion that these units would face "disparate costs" and further establishes that the Agency's rationale for a low-utilization subcategory is arbitrary and capricious.

For all of the above-listed reasons, EPA's definition of a low-utilization subcategory lacks a reasoned justification. The Agency's reliance on a single, arbitrary metric, without any deeper analysis, suggests that the Agency was simply looking for a way to exempt more units from compliance. This is wholly improper. The record shows that power plants running at a low capacity factor do not face higher costs than other power plants, much less "disparate" costs. Indeed, if EPA used the same baseline that it used elsewhere in the record, then it would have to conclude that the "low-utilization" plants are in a better position than other plants and have no need whatsoever for special treatment.

[377] Proposed TDD at 5-59.
[378] Id.
[379] See supra Section VI – Zero Discharge FGD for how we annualized costs.
[380] EPA plotted data for Option 3, but noted that "a similar comparison could be made for the technologies comprising Options 1 or 4." 84 Fed. Reg. at 64,639. In fact, compliance costs for bottom ash transport water are exactly the same for Options 3 and 4.
[381] *See Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1051 (3d Cir. 1975) (cost must be considered "on a class or category basis, rather than [on] a plant-by-plant basis").
[382] 84 Fed. Reg. at 64,639.
[383] Lexicon Publications, The New Lexicon Webster's Encyclopedic Dictionary of the English Language, Deluxe Edition (1989).
[384] For bottom ash transport water, the average (mean) treatment cost is $1.50/MWh, and 4 plants have costs that exceed $4.50/MWh. For FGD wastewater, the average treatment cost is $1.15/MWh, and 5 plants have costs that exceed $3.46/MWh.
[385] Again, a technology is economically achievable if the "costs can be reasonably borne by the industry." *Waterkeeper Alliance v. EPA*, 399 F.3d 486, 516 (2d Cir. 2005); *Rybachek v. EPA*, 904 F.2d 1276, 1290-91 (9th Cir. 1990) (discussing this standard).
[386] Proposed RIA at 4-3 to 4-4, Tbls. 4-1 and 4-2.
[387] Proposed RIA at 4-3 to 4-4, Tbls. 4-1 and 4-2.
[388] All data from ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option - DCNSE07090, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019).
[389] Id. at Tbl. 2.
[390] Id.
[391] Id.
[392] 84 Fed. Reg. at 64,639.
[393] Id.
[394] ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option - DCNSE07090, at Tbl. 2, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019).
[395] 84 Fed. Reg. at 64,639.
[396] Again, although we chose to show Option 4 costs, charts using Option 3 costs would be substantially the same.
[397] Although the data are not shown here, we also evaluated the relationship between capacity factor and compliance costs per unit of capacity factor, and found the same thing – there is no relationship between the two, and plants running at low rates of utilization do not have higher costs (expressed per unit of capacity factor) than other plants.
[398] 84 Fed. Reg. at 64,639.
[399] All data from ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option - DCNSE07090, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019).
[400] See, e.g., Proposed TDD at 5-1; Proposed BCA at 1-2.
[401] See, e.g., 84 Fed. Reg. 64,645, Table VIII-1 (showing negative costs for all regulatory options).
[402] Id. at 64,638.
[403] See, e.g., id. at 64,639, Fig. VIII-1 (showing compliance costs greater than or equal to zero for all units).
[404] Again, charts using Option 3 costs instead of Option 4 costs would show substantially the same thing.
[405] All data from ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option - DCNSE07090, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019).

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 116

Comment Excerpt:

4. EPA cannot create a subcategory based on a characteristic that changes from year to year

As discussed above, when EPA has created subcategories in past ELGs, it has done so based on fixed characteristics such as product type or manufacturing process[406] or, in the case of the 2015 ELG Rule, unit capacity. EPA has declined to create subcategories based on cost because cost varies, and EPA has determined that it would be inappropriate to create subcategories on the basis of variable characteristics.[407] EPA has also maintained that subcategories must relate to a facility's wastewater characteristics and that costs are inappropriate because costs have no effect on such characteristics.[408]

In the 2019 Proposal, EPA arbitrarily deviates from its past practice by creating a low-utilization category based on electricity generation, a characteristic that is not fixed, that varies from year to year, and that has no effect on wastewater characteristics. A plant that generates 880,000 MWh/yr for two years and then generates 870,000 MWh/yr for two years has not magically transformed into a different plant. It is the same plant, with the same fixed characteristics, the same wastewater quality, and the same ability to treat its wastewater. Yet, the 2019 Proposal would treat the plant differently after the second two-year period, relaxing the treatment requirements. If the plant goes back to generating more than 876,000 MWh, it once again enters the realm of the default BAT limitations. This clearly frustrates enforcement by creating a moving target that may change its status in the middle of an enforcement action. It also frustrates the goals of the CWA by allowing owners to game the system – as long as they never exceed the low-utilization threshold for more than a two consecutive years, they can avoid stricter pollution controls indefinitely.

[406] See Section X.A – Legal Authority for Subcategorization.

[407] See id.

[408] See, e.g., Development Document for Effluent Limitations Guidelines and Standards for Battery Manufacturing, Vol. I, 139 (Aug. 1984) ("The necessity for a subcategorization factor to relate to the raw wastewater characteristics of a plant automatically eliminates certain factors from consideration as potential bases for subdividing the category . . . treatment costs . . . have no effect on the raw wastewater generated in a plant."); Development Document for Effluent Limitations Guidelines and Standards for the Porcelain Enameling Point Source Category, 48 (Nov. 1982) (same); and Development Document for Effluent Limitations Guidelines and Standards for the Coil Coating Point Source Category, 36 (Nov. 1983) ("[T]reatment costs have no effect on the raw wastewater generated in a plant. The water pollution control technology employed at a plant and its cost are the result of a requirement to achieve a particular effluent level for a given raw wastewater load. It does not affect the raw wastewater characteristics, and thus does not impact subcategorization.").

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 117

Comment Excerpt:

5. Allowing an additional 2-year compliance extension after the low-utilization threshold is exceeded is arbitrary and will result in the discharge of avoidable pollution

The 2019 Proposal provides a 2-year compliance extension for any previously low-utilization unit that starts generating more than 876,000 MWh/yr (or otherwise fails to certify that it qualifies as a low-utilization unit).[409] This creates two problems. First, it arbitrarily allows for two additional years of excess pollution, despite the fact that treatment systems can be purchased or leased, installed, and operational over much shorter time frames. For example, Purestream's AVARA system "can be built in 180 days and is deployable within two days of on-site delivery."[410]

The second problem is that the two-year window allows plants to drift back and forth across the low-utilization threshold without ever installing the technology that would otherwise be BAT. If, for example, a plant exceeded the threshold over a two-year period, it could generate less than 876,000 MWh over the next two years and re-certify as a low-utilization plant before it had to comply with the default limitations. In this way, plants could theoretically generate more than 876,000 MWh/yr, averaged over a long-term period of four or more years, but never have to install BAT technology, so long as there are sufficiently frequent 2-year periods over which the plant does generate less than 876,000 MWh/yr.

Although EPA claims that, anytime the tiered limits are triggered, the 2019 Proposal would "preclude future use of the low utilization subcategory" for plants that fail to certify that they qualify for the subcategory, the text of the proposed rule does no such thing. Instead, the proposed regulatory language explains how a unit gets into the subcategory (by certifying that it generated less than 876,000 MWh/yr)[411] and what happens when a unit leaves the subcategory. There is nothing in the Proposed Rule that would prevent a unit from re-entering the subcategory. If EPA intends to make departure from the low-utilization subcategory permanent, it should say so in the text of the rule by, for example, amending 40 C.F.R. § 423.13(g)(1)(iii)(B) to say "such units shall be precluded from re-certifying as low-utilization boilers in the future, regardless of electricity generation rate."

[409] See, e.g., 84 Fed. Reg. at 64,674.
[410] ERG, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367, at M-2, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019).
[411] 84 Fed. Reg. at 64,672 (proposed 40 C.F.R. § 423.11(z)).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 118

Comment Excerpt:

6. EPA has not shown that the technology bases for the proposed low-utilization subcategory are BAT.

To the extent that EPA has any authority to create subcategories, it must make a BAT determination for each subcategory using the same statutory factors that it uses to identify BAT for the industry as a whole and it must apply the same standards regarding availability and economic achievability.[412] For the low-utilization subcategory, EPA proposes to impose limitations based on chemical precipitation (for FGD wastewater) and surface impoundments with Best Management Practices plans (for bottom ash transport water).[413] EPA selected these technologies without making a BAT determination and without evaluating whether more stringent technologies might be BAT for the subcategory. As a result, EPA arbitrarily and impermissibly selected technologies that are clearly not the Best Available Technology for each wastestream.

[412] See Section X.A – Legal Authority for Subcategorization; *Chem Mfrs. Ass'n v. Nat. Res. Def. Council, Inc*., 470 U.S. 116, 130-131 (1985); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 214-15 (5th Cir. 1989); *Tex. Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 934 (5th Cir. 1998).
[413] 84 Fed. Reg. at 64,630.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 120

Comment Excerpt:

EPA has flatly failed to demonstrate why it believes chemical precipitation to be BAT for the proposed low-utilization units. It has not shown that these units are qualitatively different from other units in the industry nor that they have different treatment capabilities. Although EPA makes a superficial attempt to show that the costs of treating FGD wastewater with what would otherwise be BAT (chemical precipitation plus biological treatment) are higher for the low-utilization units, that attempt does not stand up to scrutiny, as described above. More importantly, EPA never evaluates whether the costs of Option 3 or Option 4 technologies could be "reasonably borne" by the proposed subcategory – as the CWA requires.[418]

Taking all available record evidence into account, there is simply no basis for distinguishing between the so-called "low-utilization" units and other units, and there is no basis for concluding that chemical precipitation is BAT for FGD wastewater. The record does show that EPA must identify membrane filtration as BAT, and this applies equally to low-utilization units, which means that there is no basis for a low-utilization subcategory.

[418] *Waterkeeper All., Inc. v. EPA*, 399 F.3d at 516; *Rybachek v. EPA*, 904 F.2d at 1290-91 (discussing this standard).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 121

Comment Excerpt:

With regard to bottom ash transport water, the same logic applies. EPA has provided no evidence or analysis to support the idea that surface impoundments are BAT for the low-utilization units.

Indeed, EPA's determination flies in the face of recent Circuit Court jurisprudence, which strongly rejected EPA's selection of surface impoundments as BAT for legacy wastewater and leachate.[419] Surface impoundments are simply not the "Best Available Technology" for any wastestream, and EPA provides no evidence to the contrary.

[419] See Section III - Southwestern Electric.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 123

Comment Excerpt:

As with FGD wastewater, taking all record evidence into account, EPA must conclude that closed-loop or dry handling is BAT for bottom ash transport water, and this applies equally to low-utilization units, which means that there is no basis for a low-utilization subcategory.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 124

Comment Excerpt:

7. EPA should revise the proposed rule's implementation requirements for the low utilization subcategory.

Although we strongly oppose EPA's creation of a subcategory for low utilization boilers, EPA should revise the proposed implementation requirements and reporting requirements for the low utilization subcategory to ensure that plant owners and operators are not abusing the proposed subcategory. As discussed above, EPA is proposing to include tiered limitations for units in the low utilization subcategory. If the proposed low utilization subcategory is to be finalized, which we believe it should not, EPA must retain the tiered limitations as they are critical for enforceability and to ensure that plant operators do not game the system.

EPA's proposed low utilization subcategory is based on the fluctuating net generation reported annually to the U.S. Energy Information Administration.[423] As a result, EPA is proposing that boiler "net generation" be determined by "the average of the most recent two calendar years of net generation for that boiler," which cannot exceed 876,000 MWh per year.[424] According to EPA, "the use of a two-year average will ensure that a low utilization boiler responding to a single extreme demand event in one year (e.g., unexpectedly high peak demand in summer or winter) can still qualify for this subcategory if its average net generation over the two years remains below 876,000 MWh."[425] Furthermore, "the facility must annually provide the permitting authority an updated two-year average net generation for each subcategorized boiler within 60 days of submitting annual net generation information to the EIA."[426]

Although EPA is attempting to justify the agency's use of a two-year average net generation, it fails to realize that a two-year average could allow plant owners or operators to game the system by intentionally exceeding the 876,000 MWh threshold by a significant margin in a given year. We understand the need to account for unexpected extreme demand events.[427] However, we also strongly believe that there should be adequate provisions in place to prevent unethical behavior on behalf of plant operators. For instance, if a unit runs significantly under the low utilization threshold in the first of two years, there is nothing preventing the plant operator from intentionally exceeding the threshold in the second year as long as they still do not exceed the two-year average net generation. In order to ensure that plant operators do not intentionally run significantly over the low utilization threshold in any one particular year, EPA should require that participating boilers' net generation not exceed the 876,000 MWh threshold by more than 10% in either of the two most recent calendar years.

Additionally, EPA is proposing that facilities participating in the low utilization subcategory "annually recertify that the boiler continues to meet the requirements of this subcategory, along with an updated two-year average net generation calculation and information for each applicable boiler."[428] As mentioned *supra*, if a boiler exceeds the threshold for eligibility for this subcategory, it would have two years to install the necessary treatment equipment and be subject to the second tier of effluent limitations for discharges of FGD wastewater and BA transport water. EPA should require that the proposed annual net generation recertification submissions be made available on the permitting authority's website and sent to anyone who filed comments on a permit. This would ensure that the necessary parties as well the public are adequately involved and notified. Furthermore, EPA should require that if a boiler exceeds the threshold for this subcategory, the operator must notify the permitting authority and interested parties immediately, rather than wait until the facility's time to annually recertify. EPA should ensure that there are no gaps between when a facility no longer qualifies for the low utilization subcategory and when the two-year deadline for the second tier of limitations kicks in.

In addition, EPA should strongly consider requiring enforceable caps on generation for any units that opt into this subcategory. Or alternatively, if EPA truly believes that it can substantiate its purported concerns about units running at a low capacity factor, then EPA should consider re-defining this subcategory on the basis of capacity factor, and should require enforceable caps on capacity factor, as it has done elsewhere. For example, as discussed above, the Boiler MACT Rule includes a subcategory for "limited-use boilers and process heaters," but requires a "federally enforceable annual capacity factor of no more than 10 percent."[429] Here, EPA should strongly consider restricting the availability of the low utilization subcategory to units that have federally enforceable caps on net generation or capacity factor to prevent owners from gaming the system and improperly taking advantage of what amounts to a very generous loophole.

In summary, EPA should not finalize the proposed subcategory for low utilization boilers because the subcategory is unjustified, and therefore, invalid under the Clean Water Act. If EPA intends to finalize the subcategory, the agency must revise its two-year net generation averaging approach and its reporting requirements as recommended above in order to better ensure that plant operators cannot abuse the proposed system for the low utilization boiler subcategory.

[423] 84 Fed. Reg. at 64,665.
[424] Id.
[425] Id. at 64,665-66.
[426] Id. at 64,666.
[427] Id. at 64,665.
[428] Id. at 64,667.
[429] 40 C.F.R. § 63.7575.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 130

Comment Excerpt:

1. Low-Utilization Units Are Not Peakers Essential For Reliability.

EPA's case that the low-utilization subcategory is somehow necessary or even helpful in retaining reliability finds no support in the record. EPA incorrectly equates low-utilization units with "peakers" and then wrongly asserts that such peaking units are important for reliability. The proposed rule defines low-utilization units in terms of megawatt-hours of operation annually, not capacity factors. This subcategory therefore sweeps in small units running at high capacity factors, as well as larger units running at low capacity factors.[434] It includes units such as those at Plant Hammond in Georgia, which had negative net generation for much of 2016—such units are clearly not essential for reliability. It also does not differentiate between low capacity factor units that operate as seasonal peakers, and those that simply operate at a very low level, such as their economic minimum, most of the year.

Moreover, coal units do not operate reliably as peakers, since many can take more than 24 hours to start up,[435] and have a high percentage of failed starts.[436] Grid reliability does not require units that operate infrequently (low-utilization units)—it requires resources that can quickly and accurately respond to changes in load, frequency and voltage.[437] However, frequent cycling imposes wear and tear on thermal system components that render coal plants prone to forced outages. An analysis by the United States Department of Energy's National Energy Technology Laboratory found that the forced outage rate for coal units more than doubles when those units are cycled frequently as compared to when they are operating at a steady output.[438] In other words, relying on coal units to operate as peakers is a poor strategy to ensure reliability.

To the extent that low-utilization coal plants *in fact* serve peak loads, this is because it is only during peak load events, when power prices increase, that coal plants are economic to operate.[439] That expensive plants come online during peak load events says nothing about how important those plants are for reliability. If a handful of coal plants were no longer available to operate during peaks, the high wholesale prices during peak events will incent entry by and operation from more reliable and lower cost generation resources, as well as demand response.[440]

EPA's own IPM results show that the effect of the low-utilization subcategory on coal retirements is negligible – less than a one GW difference in coal retirements in each year for which EPA reported results.[441] Retirements of this scale hardly register on the U.S. bulk electric system, which at the end of 2018 had 1,098 GW of capacity installed.[442] IPM modeling undertaken by the Natural Resources Defense Council shows that even a more rigorous standard requiring zero discharge of all FGD and bottom ash wastewater, including for units projected to fall into EPA's proposed low-utilization subcategory, only 200 MW of additional coal capacity retires compared to a base case in which the 2015 standards are implemented.[443] These IPM results, unsurprisingly, revealed no reliability problems associated with this extremely small level of retirements.[444]

In most regions of the United States, electric generation capacity is oversupplied. The vast majority of the units that would fall into the low-utilization subcategory are in the SERC NERC region, with a smaller number in the PJM region. The four SERC sub-regions have anticipated 2024 reserve margins of between twenty-five percent and thirty-six percent, and a cumulative expected capacity surplus of nearly twenty-five GW.[445] PJM has an anticipated 2024 reserve margin of thirty-four percent, and an expected capacity surplus of nearly twenty-seven GW.[446] For comparison, the reference margin level, or target reserve margin needed for reliability in these two regions is 15% and 15.7%, respectively.[447] As such, there is ample generation capacity available today to fill any gaps left by expensive, low-utilization coal plants that might retire absent a carve-out from the ELGs. And any retirements would likely be quickly replaced by new entrants given the healthy investment environment for generation.

[434] See Section X.D - Low Utilization.
[435] See, e.g., Southwest Power Pool Market Monitoring Unit, Self-committing in SPP markets: Overview, impacts, and recommendations at 21 & Fig. 4-10 (Dec. 2019), available at https://assets.documentcloud.org/documents/6573451/Spp-Mmu-Self-Commitment-Whitepaper.pdf;(attached).
[436] U.S. EPA Office of Air and Radiation, Assessment of startup period at coal-fired electric generating units – Revised (Nov. 2014), at tbl. 1 (showing that across the two-year period evaluated, pulverized coal boilers failed to start in 2,103 out of 9,467 total starts - circulating fluidized bed boilers performed only slightly better) (attached).
[437] See, e.g., Michael Milligan, Sources of grid reliability services, ELECTRICITY J., 31:9, at 1-7 (Nov. 2018) (attached).
[438] Nichols, C. "Characterizing and Modeling Cycling Operations in Coal-fired Units". EIA Modeling Meeting. (June 2016), https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/EIA%20coal-fired%20unit%20workshop-NETL.pdf (attached).
[439] See, e.g., Michael Goggin, Grid Strategies LLC, Fossil lab misses mark in cold weather "resilience" report (Mar. 28, 2018), http://sustainableferc.org/fossil-lab-misses-mark-in-cold-weather-resilience-report/ (noting that increased coal unit operation during severe winter weather events reflects higher costs of those units, not their necessity for reliability) (attached).
[440] Id.
[441] See Summary Comparison of IPM Results, Coal Retirements tab, Docket ID No. EPA-HQ-OW-2009-0819-8166.
[442] U.S. Energy Information Administration, Electricity explained, at U.S. Energy Information https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.
[443] See Section XIII.D – IPM Modeling.
[444] See id.
[445] North American Electric Reliability Corporation, 2019 Long-Term Reliability Assessment, Detailed Findings at Fig. 1 & tbl. 1 (Dec. 2019), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf (attached).

[446] Id.
[447] Id. at tbl. 1.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 5

Comment Excerpt:

- APPA generally supports BAT for the Low Utilization Boiler subcategory but the current proposal remains problematic for several reasons, including a low initial threshold, the possibility of the imposition of additional costs, uncertainties which may result in a waste of resources, and unclear timeframes and deadlines.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 17

Comment Excerpt:

A. The BAT for the Low Utilization Boiler Subcategory Should Be Amended to Include a Higher Threshold, Consider Costs, and Streamline Certification Requirements

EPA is proposing to establish a subcategory for "boilers with low utilization based on the statutory factors of cost and non-water quality environmental impacts." For FGD wastewater, EPA is proposing chemical precipitation as BAT and for BA transport water, EPA is proposing surface impoundments plus a best management practices (BMP) plan. EPA's rationale for this subcategory is based on recent data showing that factors, including low natural gas prices, have led to a decline in capacity utilization for the majority of coal-fired boilers. Therefore, the 2015 Rule requirements are too costly for these facilities.

APPA generally supports the proposed subcategory for boilers with low utilization. In fact, APPA and its members advocated for EPA to include this subcategory. The Association agrees that due to changed utilization, EPA's reliance on nameplate capacity alone is problematic and electricity production should be considered. APPA generally supports the subcategory created in the 2015 Rule for those units with 50MW or less nameplate capacity and that the additional subcategory proposed by EPA based on production is necessary. But APPA believes a better approach would be to switch from nameplate capacity to megawatt hours. Specifically, changing the subcategory threshold from 50 MW to say 438,000 MWh would capture those units that are bigger in capacity but which have a lower production. To be fully effective, APPA suggests the following amendments to EPA's proposal.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 18

Comment Excerpt:

B. EPA Should Consider Restructuring the Subcategory for Small Generating Units of 50 MW or Less

The 2015 Rule created a subcategory for small generating units, those with a nameplate capacity of 50MW or less. In this Proposed Rule, EPA is not proposing any changes to that subcategory. However, EPA might, nonetheless, consider the following changes to that subcategory.

APPA suggest that units that certify to operate below 438,000 MWhs (as a two-year average net generation) would not be subject to BAT requirements for FGD wastewater or BA transport water. To the extent any size unit operates at a MWh level consistent with that of a 50 MW unit, it should be exempt from additional BAT requirements for BA transport water and FGD wastewater, even though it will remain subject to the other BAT requirements of the 2015 ELG rule.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 19

Comment Excerpt:

C. Low Utilization Subcategory Units Should Not be Subject to Any New BAT/PSES Limits for FGD Wastewater

The Agency proposes and solicits comment on the select of “chemical precipitation as the technology basis for BAT for FGD wastewater, with effluent limits for mercury and arsenic” for units in the low utilization subcategory. [50] The Association believes EPA should not adopt any new FGD BAT/PSES limits for this subcategory. As EPA notes, low utilization boilers tend to operate only during peak loading, and therefore are necessary to “ensuring electricity reliability in the near term.”[51] Market pressures and regulatory requirements have changed operating conditions for coal-fired units. As a result, many coal-fired boilers in operation today are cycling and peaking units with low capacity factors.[52] In 2019 the annual capacity factor for coal-fired boilers was 53.6 percent, as of October 2019 average capacity factor was 48 percent.[53] Hence, there is a direct relationship to generation and the amount of pollutants discharged. Peaking and cycling units produce substantially less amounts of FGD wastewater and BA transport water compared to base load units.

50 84 Fed. Reg. at 64,639.
51 Id.
52 Capacity factor means the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.
53 U.S. Energy Information Administration, Electric Power Monthly, “Table 6.07.A Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels” https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a (last visited January 16, 2020).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 22

Comment Excerpt:

F. APPA Supports the Proposed Savings Clause for the Low Utilization and Retirement Subcategories

In this Proposed Rule, EPA is proposing a savings clause to be included in all permits for facilities seeking to be included in either the low utilization or retirement subcategory. EPA’s rationale is that these facilities should be offered protections in the event they receive an emergency order issued by the DOE under section 202(c) of the Federal Power Act or a state issued reliability must-run agreement.

APPA supports the proposed savings clause. These units would be subject to less stringent limitations if they qualify for either of these subcategories. Should the units then be required to run under either a Federal or State issued order, they may, involuntarily, no longer qualify for the subcategory. APPA agrees that as long as the unit can show it is under such an order, it should be able to invoke the savings clause to show that but for the order, it would continue to meet the requirements of the subcategory

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 14

Comment Excerpt:

Additionally, EPA should consider allowing a comparable flow alternative threshold to the low utilization subcategory. This will allow units that can substantially reduce or control their FGD discharge based on operating conditions to pursue technologies that would ultimately remove greater than 90% of the pollutant loading. Boilers that produce more than 876,000 MWh per year but have relatively low flow may encounter disparate costs associated with installation and operation of a treatment system to meet the FGD wastewater limitations for non-low utilization boilers. Therefore, defining this subcategory to include a comparable flow threshold alternative would more accurately capture the set of low-utilization boilers that should properly be placed in their own separate subcategory.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 50

Comment Excerpt:

EPA should also finalize a subcategory for a subset of low utilization boilers that may serve in a critical capacity for ensuring electric system resiliency and reliability.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 25

Comment Excerpt:

- APPA suggests restructuring the current subcategory for small generating units of 50MW or less.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 27

Comment Excerpt:

- APPA supports the proposed savings clause for the low utilization and retirement subcategories.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 35

Comment Excerpt:

1. EPA's Threshold of 876,000 MWh Per Year Is Too Low

EPA is proposing to establish a subcategory for low utilization units producing less than 876,000 MWh per year. EPA's rationale is that disparate costs to meet the proposed FGD wastewater and BA transport water BAT limitations and pretreatment standards are imposed on boilers with low capacity utilization. EPA cites data showing the costs per MWh produced as measured by the status quo versus the 2015 Rule baseline, arguing there is a significant difference between boilers above and below 876,000 MWh per year.

APPA agrees that a subcategory for low utilization boilers is important. In the 2015 Rule, EPA simply focused on the nameplate capacity creating a subcategory for those boilers with a 50 MW or less nameplate capacity. However, due to industry changes, many boilers may, in fact, be over the 50MW nameplate capacity yet have limited MW production. APPA agrees that creating a subcategory for those boilers with lower MW production is necessary. However, APPA believes that the threshold of 876,000 MWh per year proposed by EPA is simply too low.

APPA recommends an alternate low utilization threshold of 1,314,000 MWh. This alternative threshold more accurately represents the subset of units that will incur disparate costs under the Proposed Rule without the benefit of the low utilization subcategory. As is standard practice, EPA has calculated the "cost-effectiveness" of the proposed BAT requirements in terms of toxic-weighted pound-equivalents (TWPEs) of pollutants removed:

EPA often uses cost-effectiveness analysis in the development/revision of effluent limitations guidelines and standards to evaluate the relative efficiency of alternative regulatory options in removing toxic pollutants from the effluent discharges to the nation's waters. Although not required by the Clean Water Act, cost-effectiveness analysis is a useful tool for evaluating regulatory options that address toxic pollutants. [41]

The TWPE metric is used to measure the benefits of pollutant removals to the public. The agency has used this metric over several decades in determining whether the rule is achieving cost-effective pollutant reductions. ELGs typically cost less than $100/TWPE ($1981).[42] Rules well in excess of this benchmark were determined to be not cost-effective and not BAT. The Association engaged AECOM to evaluate EPA's analysis of the low utilization subcategory threshold. Appendix A includes a copy of their report. AECOM's analysis suggests an alternative low utilization threshold of 1,314,000 MWh is a more appropriate threshold. Based on AECOM's analysis for BA transport water, the average annual costs per TWPE removed using purge technology is $4,076 ($1981) (excludes units that have already upgraded) for units with net generation between 876,000 MWh and 1,314,000 MWh. The average annual costs per MWh would be $1.70. Meaning, approximately $1,790,253 in costs would be incurred by customers. Applying an alternative low utilization threshold of 1,314,000 MWh is reasonable as the alternative threshold would include 34 additional peaking and cycling units. Turning to the FGD analysis AECOM performed, the average annual costs per TWPE removed is $359($1981)/TWPE and $0.61($2018)/MWh for units between 876,000-1,314,000 MWh net generation. Roughly adding $598,034 in annual costs.[43] EPA is correct to provide regulatory relief by establishing a utilization threshold for units that face disparate costs as these low utilization units are increasingly operating at, or below, 40 percent annual utilization. The Association recommends EPA adopt this alternate threshold.

41 78 Fed. Reg. at 34,503 col. 2.
42 The Cost Effectiveness Factor is calculated using the 1981 dollars, the year this benchmark was first adopted by BP A. By standardizing the real value of money, EPA can fairly compare cost-effectiveness of rulemakings over time. The conversion factor for converting 2013 dollars into 1981 dollars is 0.37 (from Engineering News Construction Cost Index). See Table F-5, EPA Regulatory Impact Analysis, September 25,2015 for the list of Rules.
43 Appendix A "AECOM Calculations of Cost Effectiveness for Bottom Ash Transport Water and FGD Wastewater Treatments, and the Impacts on Steam Electric Units in Different Megawatt Hour Size Categories Based on EPA Loadings Spreadsheets in the Proposed Steam-Electric Rule"(January 2020).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 37

Comment Excerpt:

3. The Certification Requirements for the Low Utilization Subcategory are Too Onerous

Of the five new reporting and recordkeeping standards in the Proposed Rule, one proposes that facilities seeking the low utilization subcategory must submit an initial and annual certification. This certification must be submitted to the permitting authority, as part of any permit renewal or re-opening, and must include a calculation of the two-year average net generation for each applicable boiler, including any underlying data. Once the permitting authority has ruled that the boiler meets the requirements to be included in this subcategory, the facility must then annually recertify that the boiler continues to meet the requirements of the subcategory and submit updated two-year average net generation calculations with underlying information. This annual recertification must be made to the permitting authority within 60 days of submitting the annual net generation data to the Energy Information Administration (EIA).

The Proposed Rule requires that the initial and annual recertification shall be based on information that the facility submits to the EIA and shall include copies of all underlying forms previously submitted, as well as any supplemental information and calculations the facility used to determine the two-year average annual net generation. If the facility has multiple boilers, the information must attribute consumption to each boiler proportional to that boiler's nameplate capacity.

The Proposed Rule also states that for any facility with a low utilization boiler that fails to recertify that the two-year average net generation is below 876,000 MWh per year, regardless of the reason, must then meet the discharge limits as set by the permitting authority.

The current Proposed Rule is ambiguous and onerous. APPA suggests that EPA streamline the certification requirements, set forth clearer timeframes and deadlines for certification, as well as allow a grace period for ministerial failures to certify by the deadline. APPA recommends EPA allow permittees to submit their initial certification to their permitting authority up to three years after the effective date of the final rule. The three-year time frame to claim eligibility for the low utilization subcategory provides time to make a reasoned decision considering the final ELG rule and amendments to the CCR rule.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 38

Comment Excerpt:

4. Facilities Should Only Have to Certify Meeting the Low Utilization Threshold

EPA has proposed to require units to operate in a “low utilization” mode to qualify for the subcategory.

When a facility seeks to have limitations for one or more subcategorized boilers incorporated into its permit, the EPA is proposing that the facility provide the permitting authority its calculation of the average of the most recent two calendar years of net generation for that boiler(s). A facility wishing to seek this subcategory, must operate below this threshold before the latest implementation dates, but a permitting authority should also refrain from establishing a ‘no later than date’ which would restrict a facility from demonstrating two years of reduced net generation.[48]

The preamble seems to suggest the unit must have operated in low utilization mode for the two years prior to the latest applicability date that applied to that unit. This would seem to disadvantage potential low utilization boilers based on past operations, verses their best performance in the future. If a permittee is willing to certify that it will operate the unit according to the low utilization boiler threshold and requirements, the certification should be enough to qualify for inclusion in the subcategory. This approach simplifies the process for both the permittee and permitting authority. Further, EPA proposes that any failure to recertify requires compliance with the rule within two years.[49]

48 84 Fed. Reg. at 64,665.
49 See §§ 423.13(g)(2)(iii)(B), 423.13(k)(2)(iii)(B).

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 28

Comment Excerpt:

Also, EPA's proposed subcategory for "low-utilization units" producing less than 876,000 megawatt hours (MWh) per year should be further developed by the Agency. EPA must pay particular attention to developing the record with respect to its two possible justifications for this subcategory: disproportionate costs and non-water quality environmental impacts, including energy requirements.

9c <u>Subcategorization – High FGD Wastewater Flow</u>

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 2

Comment Excerpt:

EPA should establish a separate subcategory for high recycle rate FGD systems, including appropriate measures to maintain system water balance.

The proposed rule includes three subcategories for facilities with high flue gas desulfurization ("FGD") flow, low utilization boilers, and boilers retiring by 2028.[3] The preamble to the proposed rule invites recommendations for additional subcategories, particularly with respect to "the ability .... of existing systems" to treat FGD wastewater and "what limitations should apply to those facilities[.]"[4] Cleco submits that the Agency should develop a fourth subcategory for high recycle rate FGD systems using inhibited oxidation and solidification as model technology.[5] These systems are materially different with respect to the statutory BAT factors of "the process employed, the engineering aspects of the application of various types of control techniques, process changes, [and] the cost of achieving such effluent reduction[.]"[6] Appropriate control measures for high recycle rate FGD systems should include a general prohibition on discharges except for those necessary to maintain system water balance due to unusual precipitation-related inflows, much like the newly proposed control measures for high recycle rate bottom ash transport water ("BATW") systems. These measures could be fmther coupled with some combination of the use of Best Management Practices ("BMPs") to reduce authorized discharges and numeric limits on Total Suspended Solids ("TSS") and Oil & Grease ("O&G") applicable when a facility must discharge to maintain water balance.

[3] Proposed Rule, 84 Fed. Reg. at 64,622.
[4] Id at 64,663 ("The EPA solicits comment on . . . whether any existing systems with demonstrated issues meeting these limits would be best addressed through FDF variances or through subcategorization.").

[5] As is always the case for BAT standards, a facility would not need to actually employ inhibited oxidation or solidification.
[6] 33 U.S.C. § 1314(b)(2)(B).

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 4

Comment Excerpt:

2. Statutory BAT Factors

Cleco does not take issue with the conclusion in the 2015 rule or the proposed rule that high recycle rate FGD systems are not nationally available. However, the Agency should take a harder look at these systems as the basis for a separate subcategory. Subcategorization is an appropriate means of recognizing differences across an industry when promulgating BAT standards, and, as the proposed rule explains, a subcategory is justified if the covered facilities differ with respect to the statutory BAT factors.[27] In this case, a subcategory for high recycle rate FGD systems would be based on the process employed, the engineering aspects of the control technology, process changes, and cost.[28]

First, high recycle rate systems, and particularly inhibited oxidation systems, employ a materially distinct process from the majority of wet scrubbers. As the Agency has recognized for some time, "most FGD treatment systems currently being used do not significantly affect the level of chlorides in the wastewater[,]" with the result that "the treated FGD wastewater is not recycled back to the FGD scrubber."[29] High recycle rate systems, in contrast, might lack the predischarge wastewater treatment systems common to higher-purge systems (with the exception of settling ponds).[30] This is particularly true for inhibited oxidation systems since they are the most likely to pe1mit high recycling.[31]

Second, because the initial process of a high recycle rate system is materially different, process changes to incorporate chemical precipitation or biological treatment are more complex. High recycle rate systems do not have infrastructure to suppmt large discharges, nor do they have major treatment systems for such discharges. The modest, infrequent nature of such discharges would greatly complicate effective operation of biological treatment, for instance. Those complications also implicate the separate statutory factor of engineering aspects of the control technology. Third, and most importantly, the proposed rule's baseline limitations for FGD wastewater would impose severely disproportionate costs on high recycle rate systems. The Technical Development Document for the proposed rule (the "2019 TDD") implies that the average capital cost for meeting the proposed FGD BAT is roughly $13.3 million (in 2018 dollars).[32] Cleco's Dolet Hill station would exemplify the unreasonableness of these costs.

[27] Proposed Rule, 84 Fed. Reg. at 64,624.
[28] See 33 U.S.C. § 1314(b)(2)(B).
[29] Final Detailed Study Report at 4-10.
[30] Id. at 4-11.

[31] Id.
[32] See Supplemental Technical Development Document at 5-59 tbl. 5-9 (Regulatory Option 2 ($934 million divided by 70 plants)). Cleco expects that the 2019 TDD might underestimate these capital costs. Record evidence indicates capital costs above $33 million for installation ofFGD treatment systems at a single facility. See EPA, Site Visit Notes: Progress Energy Carolinas' Roxboro Steam Electric Plant 7 (2008) (Docket No. EPA-HQ-OW2009-0819-0686).

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 6

Comment Excerpt:

Taken together, these four statutory BAT factors give EPA more than "'a rough basis for subcategorization"' of complete-recycle FGD systems.[37]

[37] id. at 64,624 (quoting Chem. Mfrs. Ass 'n v. EPA, 870 F.2d 177,215 n.137 (5th Cir. 1989)). [Proposed Rule, 84 Fed. Reg.]

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 10

Comment Excerpt:

Source Subcategory for High FGD Flow Rates

For similar reasons, America's Power supports the establishment of a source subcategory for existing coal-fired generating units with extremely high FGD purge flow rates.

In the proposed rule, this new source subcategory would apply to those coal-fired generating facilities with FGD purge flow rates greater than four million gallons per day (after accounting for each facility's ability to recycle the wastewater). We believe that the establishment of this subcategory is needed to avoid placing disproportionately high costs on these high-flow facilities because the FGD wastewater treatment costs increase significantly when these much higher volumes of wastewater are processed through a biological treatment system for removing the nitrogen compounds, selenium and other metal constituents. As EPA itself recognizes in the proposed ELG rule, the treatment costs for a high-flow facility are exorbitantly high, specifically, "five to six times higher" than the capital and operating costs incurred by facilities that have more typical FGD wastewater flow rates and generate similar amounts of electricity.[13]

Imposing these excessively high costs on this subcategory of coal-fired units could force their premature retirement by putting them at a competitive disadvantage compared to other electric generating sources that are not subject to these very high compliance costs for treating smaller volumes of FGD wastewater. To avoid these adverse disparate cost impacts, we agree with EPA's proposal to set for this subcategory of high-flow facilities a more cost-effective effluent discharge limitation for FGD wastewater based on chemical precipitation alone (i.e., without biological treatment that is generally required for other affected facilities).

13 84 Fed. Reg. at 64,638.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 59

Comment Excerpt:

d. High FGD flow subcategory.

1. Background

In the 2019 Proposal, EPA proposes a high FGD flow subcategory ("High Flow Subcategory"), which would establish BAT based on chemical precipitation alone for facilities with purge flows greater than four million gallons per day.[154] The High Flow Subcategory would apply only to the Cumberland Fossil Plant ("Cumberland Plant"), a coal plant owned and operated by the Tennessee Valley Authority ("TVA"), the nation's largest publicly-owned utility.[155]

[154] 84 Fed. Reg. at 64,638.
[155] Danielle Stewart, Environmental Research Group, Alternative Flue Gas Desulfurization Treatment Costs for High Flow Plants – DCN SE07126, EPA-HQ-2009-0819-8200 (Oct. 30, 2019) ("[O]nly one plant, Cumberland (plant ID 6329), meets the requirements of this subcategory.")

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 61

Comment Excerpt:

Although, as discussed throughout these comments, technologies exist and have long existed to remove toxic pollutants from FGD wastewater, for the better part of the past decade, TVA has sought to exempt itself from its obligation under the CWA to install modern water pollution controls at the Cumberland Plant.

During the comment period for the 2015 ELG Rule, TVA requested a less stringent subcategory for Cumberland. TVA wrote that "a uniform BAT requirement for all FGD designs is impracticable and that a subcategory or other approach for existing 'once through' and/or high-flow FGD designs is warranted."[173] TVA primarily argued that Cumberland could not achieve the ELGs because its FGD system, due to its metallurgy, would corrode if it recirculated wastewater. And TVA claimed that modifying Cumberland's scrubber material to something more corrosion resistant, or simply complying without recirculation, would be too expensive.[174] In the 2015 ELG Rule, EPA rejected these claims and denied TVA's request for a special subcategory. EPA disagreed with TVA's technical premise, finding Cumberland could recirculate some wastewater without corroding its FGD system. Moreover, EPA found its proposed BAT to be affordable for industry as a whole, as the Clean Water Act requires.[175]

Rather than complying with the 2015 ELG Rule, TVA has persisted in its efforts to seek less stringent effluent limitations for Cumberland. In April 2016, TVA applied for a Fundamentally Different Factors ("FDF") variance to exempt Cumberland from the 2015 ELGs. TVA rehashed the same arguments: Cumberland can't recycle wastewater, so compliance would be expensive.[176] EPA never granted TVA's application,[177] and the State of Tennessee incorporated the 2015 ELGs into TVA's NPDES permit, which was reissued in 2018.[178] In TVA's comments on the draft permit, TVA expressly stated that it could comply with the 2015 ELG Rule's limits on mercury and arsenic by September 1, 2021, when the utility would complete installation of a new physical-chemical treatment system for the Cumberland Plant.[179]

Meanwhile, a coalition of industry trade groups, of which TVA is a member, had successfully petitioned the EPA to reconsider the 2015 ELG Rule.[180] TVA then lobbied EPA for special effluent limitations for Cumberland, meeting with David Ross, Assistant Administrator of the Office of Water in September 2018, to discuss the "uniqueness of their once-through systems and the need for either an FDF [variance] or some other relief in the regulation."[181]

Since that meeting, TVA has confidently assumed that, one way or another, the Cumberland Plant will not have to comply with the 2015 ELGs. In July 2019, TVA published an Environmental Assessment for the proposed construction of FGD wastewater treatment facilities, whose purpose was "to meet the regulatory limits established by EPA's ELGs for Steam-Electric Generating Facilities."[182] The draft EA explored three alternatives, only one of which would comply with the 2015 ELG Rule. TVA's preferred alternative, and the one it ultimately selected, would lead it to violate the 2015 ELGs' restrictions on selenium and nitrate/nitrite and the terms of its current NPDES permit.[183]

The High Flow Subcategory culminates TVA's years-long campaign to receive special treatment for the Cumberland Plant.

[173] EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Responses to Public Comments, Docket ID No. EPA-HQ-OW-2009-0819-4607-A1, Comment Excerpt No. 4, 3-583 (Sep. 2015).
[174] Id., Comment Excerpt No. 5, 5-35 to 5-38.
[175] Id. at 5-38 to 5-41.
[176] TVA FRF Request, Attachment 60.
[177] In December 2016, environmental groups, including the Southern Environmental Law Center and the Sierra Club, submitted comments to EPA Region 4 outlining the inadequacy of TVA's FDF variance application, which is attached and incorporated by reference. Letter from Amanda Garcia et al., Southern Envtl. Law Ctr., to Heather McTeer Toney, Envtl. Prot. Agency, re: TVA, Cumberland Fossil Plant—NPDES Permit No. TN0005789—TVA Request for Alternative Effluent Limitations for Wet Flue Gas Desulfurization System

Discharges Based on Fundamentally Different Factors Pursuant to 33 U.S.C. § 1311(n)(April 28, 2016) (Dec. 21, 2016) (Attachment 66).
[178] Tenn. Dep't Envt. & Conservation, NPDES Permit No. TN0005789 I(A)(4), at 6 (2018) (Attachment 67) ("Cumberland NPDES Permit").
[179] Tenn. Valley Auth., Cumberland Fossil Plant—NPDES Permit No. TN0005789—Draft NPDES Permit Comments, 3 (May 23, 2018) ("We suggest establishing Tier limits for mercury and arsenic that would apply on September 1, 2021, or upon construction and startup of physical/chemical treatment and division approval of the initial operating period.") (Attachment 103).
[180] Envtl. Prot. Agency, Proposed Rule, Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 82 Fed. Reg. 26,017, 26,018 (Jun. 6, 2017).
[181] September 12, 2018 email from Richard Benware to Jan Matuszko, Docket ID No. EPA HQ-2019-006928, at 61.
[182] Tenn. Valley Auth., Cumberland Fossil Plant (CUF) Wastewater Treatment Facility Final Environmental Assessment, at 5 (Jul. 2019) (Attachment 68) ("Cumberland EA").
[183] Cumberland NPDES Permit, Attachment 67 at 6. The Southern Environmental Law Center and the Sierra Club submitted comments on TVA's draft environmental assessment highlighting TVA's obligation to comply with existing law. These comments are attached and incorporated by reference. Letter from Christina Reichert et al., Southern Envtl. Law Ctr., to Ashley Farless, Tenn. Valley Auth., re: Tennessee Valley Authority's Draft Environmental Assessment for the Cumberland Fossil Plant (CUF) Wastewater Treatment Facility (May 1, 2019) (Attachment 69).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 62

Comment Excerpt:

2. EPA proposes a subcategory just for Cumberland

The High Flow Subcategory would "establish a new subcategory for facilities with high FGD flows based on the statutory factor of cost."[184] In the 2019 Proposal, EPA discusses only the Cumberland Plant in the context of the High Flow Subcategory, and a memorandum from the Environmental Research Group confirms that the Cumberland Plant will be the only member of this subcategory.[185] For the FGD wastewater category, EPA proposes to establish chemical precipitation plus biological treatment as BAT.[186] In contrast, EPA proposes chemical precipitation alone as BAT for the High Flow Subcategory.[187]

Although TVA previously stated that it could comply with the 2015 ELG Rule limits on mercury by September 1, 2021, the High Flow Subcategory would allow Cumberland to discharge nearly ten times the concentration of mercury as other FGD wastewater dischargers.[188] According to EPA, Cumberland discharges "millions of gallons per day [more] than the next highest flow rate in the entire industry."[189] EPA's proposed mercury limit coupled with its estimate of the Cumberland Plant's flows would result in the Cumberland Plant discharging over twenty times more mercury than other facilities. [190] EPA proposes no limitations for selenium or nitrate/nitrite for Cumberland.[191] The High Flow Subcategory thus shields Cumberland from the selenium and nitrate/nitrite limitations EPA proposes for the FGD wastewater category.[192]

[184] 84 Fed. Reg. at 64,638.
[185] Danielle Stewart, Environmental Research Group, Alternative Flue Gas Desulfurization Treatment Costs for High Flow Plants – DCN SE07126, Docket ID No. EPA-HQ-2009-0819-8200 (Oct. 30, 2019) ("[O]nly one plant, Cumberland (plant ID 6329), meets the requirements of this subcategory.").
[186] 84 Fed. Reg. at 64,631.
[187] Id. at 64,638.
[188] Id. at 64,673-74.
[189] Id. at 64,638.
[190] Consultant ERG estimates Cumberland's FGD Purge Flow as 5,142,240 gallons per day (gpd) and its Optimized FGD Flow as 4,418,898 gpd. Sara Bossenbroek and Danielle Stewart, Environmental Research Group, "Flue Gas Desulfurizatioon Flow Methodology for Compliance Costs and Pollutant Loadings – DCN SE07091," Docket ID No. EPA-HQ-2009-0819-8200 (July 8, 2019). Those figures are more than twice as much as the next highest rates: FGD Purge Flow of 2,153,520 gpd at Big Bend Station and Optimized Purge Flow of 1,644,985 gpd at Trimble County. Id.
[191] 84 Fed. Reg. at 64,674.
[192] Id. at 64,673.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 63

Comment Excerpt:

3. The Clean Water Act prohibits EPA's proposed subcategory.

The High Flow Subcategory is inconsistent with the requirements of the Clean Water Act, which does not authorize a subcategory of one based on cost.

a. Subcategories of One

The text, structure, and legislative history of the Act demonstrate that BAT is a categorical, industry-wide standard. Congress created a separate mechanism, the FDF variance, for plant-by-plant determinations. Prior to codification of the FDF variance in the CWA, the Supreme Court suggested in dicta that single-member subcategories are permissible.[193] But Congress's subsequent codification of a more limited FDF variance changed the Act's structure, making clear that "Congress intended 'fundamentally different' characteristics of particular plants to be considered by the EPA in a Section 301(n) FDF variance proceeding."[194]

The Clean Water Act requires the EPA to establish "effluent limitations *for categories and classes* of point sources" by applying the "best available technology economically achievable *for such category or class*, which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[195] "[S]uch effluent limitations shall require the elimination of discharges of all pollutants if the Administrator finds . . . that such elimination is technologically and *economically achievable for a category or class of point sources* . . . ."[196]

The related BAT provision requires EPA to "identify . . . the degree of effluent reduction attainable through the application of the best control measures and practices achievable . . . *for classes and categories of point sources.*"[197]

In contrast to the ELG provisions' emphasis on "categories and classes," the FDF variance in the same section authorizes modifying effluent limitations "for a facility."[198] "[W]hen the legislature uses certain language in one part of the statute and different language in another, the court assumes different meanings were intended."[199] This textual distinction between "categories and classes of point sources" and "a facility" is meaningless if an individual facility can be a category.[200]

As the courts have long recognized, "Congress intended BAT limitations to be based on the performance of the single best-performing plant in an industrial field."[201] BAT only works by comparing facilities, requiring multiple plants within a category for the standard to function as designed. The BAT standard requires EPA to compare facilities across an industrial field and to set standards based on what the single best facility is doing.

The statute provides two ways to establish BAT for a facility. One is through categorical effluent limitation guidelines, "which are nationwide standards set by the EPA Administrator to govern pollutant discharges from point sources."[202] The second method is through individual FDF variances: EPA may create a less stringent, single-facility BAT for any facility that demonstrates that it is fundamentally different with respect to at least one factor EPA considered in setting BAT for the broader category or subcategory.[203] The EPA must consider the same factors for an FDF variance that it has considered for setting BAT pursuant to § 1314(b)(2)(B)— "other than cost."[204]

The two mechanisms create a distinct structure: generalized, categorical BAT standards "are to be established prior to consideration of the characteristics of the individual plant."[205] Congress created a "coherent statutory scheme: One vehicle promulgating categorical regulations of national scope and one vehicle to address concerns relating to individual [facilities]."[206]

A subcategory of one, like the High Flow Subcategory proposed by EPA, turns BAT on its head. Rather than forcing all facilities to operate as cleanly as the single best facility, EPA would set BAT based on the single worst-polluting facility. EPA would allow Cumberland to remain the largest wastewater polluter by setting a standard lower than what any every other FGD wastewater facility must achieve. By comparing all plants to the best performers, Congress structured the BAT standard to demand improvement. "BAT must achieve 'reasonable further progress' towards the Act's goal of eliminating pollution,"[207] and EPA's proposal fails that essential requirement.[208]

[193] *See Chem Mfrs. Ass'n v. NRDC*, 470 U.S. 116, 131 (1985) ("EPA could promulgate rules . . . creating a subcategory for each source which is fundamentally different").
[194] *Chem Mfrs. Ass'n,* 870 F.2d at 236.
[195] 33 U.S.C. § 1311(b)(2)(A) (emphasis added).
[196] Id. (emphasis added).
[197] Id. (emphasis added). Analyzing this text, the Supreme Court has read ELGs as categorical mechanisms, in contrast with the Act's individual mechanisms like NPDES permits and FDF variances. *E.I. du Pont de*

Nemours & Co. v. Train, 430 U.S. 112, 136 (1977) ("The statute thus focuses expressly on the characteristics of the 'category or class' rather than the characteristics of the individual point sources. Normally, such classwide determinations would be made by regulation, not in the course of issuing a permit to one member of the class.").
[198] 33 U.S.C. § 1311(n)(1).
[199] *Sosa v. Alvarez-Machain*, 542 U.S. 692, 711 n.9 (2004).
[200] The ordinary meaning of "class" or "category" implies multiple constituent members. A single plant cannot be a category or class by itself.
[201] *Sw. Elec. Power Co.,* 920 F.3d at 1018 (quoting *Chem. Mfrs. Ass'n*, 870 F.2d at 226). See also *Kennecott*, 780 F.2d at 448 ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible.").
[202] *Sw. Elec. Power Co*., 920 F.3d at 1005.
[203] 33 U.S.C. § 1314(n)(1)(A).
[204] Id.
[205] *Du Pont*, 430 U.S. at 127 n.17. See also *Texas Oil & Gas*, 161 F.3d at 939 ("We agree that Congress intended to foreclose plant-by-plant evaluation of facilities within a subcategory.").
[206] *Chem. Mfrs. Ass'n*, 870 F.2d at 259. The Fifth Circuit panel was discussing the structural relationship of the pretreatment standards (categorical) with removal credits provision (plant-by-plant) but expressly compared that structure to the "FDF variance scheme discussed above"—about which the court stated that "Congress intended 'fundamentally different' characteristics of particular plants to be considered by the EPA in a Section 301(n) FDF variance proceeding." Id. at 236.
[207] *Sw. Elec. Power Co.*, 920 F.3d at 1006.
[208] *See Chem. Mfrs. Ass'n,* 870 F.2d at 236 (rejecting industry request for a single-plant subcategory and finding that setting BAT in a national rulemaking based on a single plant's characteristics conflicts with the structure Congress created).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 65

Comment Excerpt:

4. EPA has no reasoned basis for its policy shift in establishing the high flow category.

In the 2015 ELG Rule, EPA rejected both a high flow subcategory and the use of chemical precipitation alone to establish BAT. The EPA has provided no reasoned basis for its policy reversal.

a. <u>The High Flow Subcategory Is an Unexplained Reversal</u>.

EPA proposes a subcategory for "facilities with high FGD flows based on the statutory factor of costs."[219] EPA explains, "Based on the typical chloride concentrations in the FGD scrubber, the facility would be able to recycle little, if any, of the wastewater back to the scrubber as a means for reducing the flow volume sent to a treatment system. . . . [A]s a result of the inability to recycle these high flows, TVA stated that the cost of a biological treatment system would be high."[220] EPA takes TVA at its word, justifying the subcategory on that basis.

But in 2015, EPA considered and rejected doing exactly what it now proposes. TVA had argued that "a uniform BAT requirement for all FGD designs is impracticable and that a subcategory or other approach for existing 'once through' and/or high-flow FGD designs is warranted."[221] TVA asserted that the FGD systems' metallurgy at certain facilities, including Cumberland, could not achieve the flow minimization EPA presumed.[222] The result is that "facilities with 'once-through' and/or high-flow FGDs would unfairly bear the brunt of the industry's cost to treat to comply with the ELGs."[223]

In 2015, EPA disagreed. The agency found that the FGD wastewater BAT, chemical precipitation plus biological treatment, was "achievable and affordable for the industry as a whole."[224] Finding high FGD flow wastewater characteristics to be "within the same range" as other facilities in the category, EPA declined to create a high FGD flow subcategory.[225] EPA cited the "variability of FGD wastewater flow rates at plants," which could incentivize plants to discharge more wastewater to become part of the less stringent subcategory.[226] The scenario would likely lead to "an increase in intake water, which is non-water quality environmental impact" and "an increase in wastewater discharge volumes and potentially no reduction in pollutant loadings, which would not result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[227]

In the 2015 ELG Rule, EPA considered and rejected TVA's arguments that Cumberland's FGD system metallurgy prohibited compliance with the BAT limitations due to corrosion and operational concerns. EPA found that the Cumberland FGD system could tolerate higher concentrations of chloride than TVA stated would be possible, thus allowing for increased wastewater recirculation.[228] Highlighting several options for wastewater recycling, EPA emphasized that "plants are not required to install or operate a certain FGD wastewater treatment technology to meet the final ELG's."[229]

The only new information EPA cites for the policy shift is a brief email, in which TVA provides "preliminary estimates [of compliance costs] with an accuracy of -30% to +50%."[230] EPA has not addressed its 2015 findings that a high FGD flow subcategory would create incentive to discharge more wastewater and result in related non-water quality environmental impacts of increased intake water. Facing the same arguments TVA presented in 2015, and with essentially the same data, EPA reaches the opposite conclusion. Yet EPA fails to explain the inconsistencies of doing so.

[219] 84 Fed. Reg. at 64,638.
[220] Id.
[221] EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Responses to Public Comments, Docket ID No. EPA-HQ-OW-2009-0819-4607-A1, Comment Excerpt No. 4, 3-583 (Sept. 2015).
[222] Id., Comment Excerpt No. 5, 5-35.
[223] Id., Comment Excerpt No. 4, 3-584.
[224] Id. at 3-585.
[225] Id. at 3-586.
[226] Id.
[227] Id.
[228] Id. at 3-587.
[229] Id., Comment Excerpt No. 5, 5-40 to 5-41.
[230] See Email to Anna Wildeman (Nov. 13, 2018) - DCN SE08195, Docket ID No. EPA-HQ-OW-2009-0819.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 70

Comment Excerpt:

In the High Flow Subcategory, EPA has ignored every factor but cost. Nowhere does EPA address the non-water quality environmental impacts, despite the agency's 2015 refusal to create a high FGD flow subcategory partly because of the potential "increase in intake water, which is non-water quality environmental impact that EPA is required to consider under section 304(b) of the Clean Water Act."[251] EPA's failure to consider relevant statutory factors is arbitrary and capricious.

[251] EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Responses to Public Comments, Docket ID No. EPA-HQ-OW-2009-0819-4607-A1, Comment Excerpt No. 4, 3-586 (Sept. 2015).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 71

Comment Excerpt:

c. <u>Even if EPA had considered the BAT factors, not one supports subcategorization</u>.

TVA has argued against complying with the 2015 ELG Rule based on non-water quality impacts, process changes, and engineering aspects of the application of the 2015 BAT. TVA has argued that changing its FGD wastewater pollution control technology would "risk air compliance impacts."[252] But other plants meet their equally stringent air compliance obligations while also recycling FGD wastewater. TVA has cited concerns of increased mercury in the gypsum it markets.[253] Not only is that concern unsupported by any evidence, but protecting the economic viability of a marketing program not a reason the Clean Water Act contemplates for relaxing effluent limitations.[254] TVA has stated that recirculation "increases the complexity of wastewater which reduces its ability to be treated."[255] But other facilities overcome this same "complexity," which is present in all FGD recirculated wastewater. And as EPA found in 2015, the Cumberland Plant's FGD system metallurgy can recirculate wastewater without corroding. TVA has acknowledged the system's ability to accept up to 3,175 ppm chloride, a level sufficient to increase FGD wastewater recirculation without causing corrosion.[256] Finally, because TVA's average generation at the Cumberland Plant is much lower than EPA assumes, for the vast majority of the time the Cumberland Plant's actual flow rates are less than 4 mgd—the threshold EPA has established for the High Flow Subcategory—without any changes at all to how the units are operating.[257] In summary, the facts show that the sole plant for which EPA proposes the High Flow Subcategory does not require subcategorization.

[252] Cumberland EA, Attachment 68, at 12 (Jul. 2019).
[253] Id.
[254] In 2019, TVA reported to its state regulator that it was acquiring the wallboard facility to which it previously marketed its gypsum. Tenn. Valley Auth., Wet FGD Wastewater Treatment and Bottom Ash ELG Project Updates,Cumberland Fossil Plant, NPDES Permit No. TN0005789, Annual Report 2018 (January 24, 2019) (Attachment 71).
[255] Id.
[256] Sahu Report, Attachment 70, at 5.
[257] Sahu Report, Attachment 70, at 6-10.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
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Comment Excerpt:

d. <u>EPA Ignores Reasonable Alternatives</u>

EPA unlawfully fails to consider any alternatives. Under all four options EPA considered, BAT for the High Flow Subcategory is chemical precipitation.[258] There are numerous available technologies EPA refused to consider for high FGD flow facilities, including various combinations of chemical precipitation, biological treatment (high- or low-residence time), membrane technology, thermal technology. EPA's failure is particularly egregious because the agency failed to evaluate a single alternative—despite a congressional mandate to find the "best available technology economically achievable."

[258] See 84 Fed. Reg. at 64,630.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
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Similarly, in proposing the High Flow Subcategory, EPA fails to consider Cumberland's alternatives for meeting the same standard as other facilities. Assuming Cumberland's scrubber metallurgy prevents compliance with the FGD wastewater category's BAT (a position EPA rejected in 2015), TVA could modify its scrubber materials or line its absorbers to increase resistance to corrosion. TVA could replace some or all high sulfur coal with low sulfur and low chlorine sub-bituminous Powder River Basin coal at Cumberland. As EPA informed TVA in 2015, "plants are not required to install or operate a certain FGD wastewater treatment technology to meet the final ELG's."[259] EPA now assumes that BAT mandates a single technology, arguing that Cumberland's inability to implement that technology justifies special treatment. Erroneously ruling out one existing technology for one plant does not justify weakening BAT, a "technology-forcing" standard Congress created "to press development of new, more efficient and effective pollution-control technologies."[260] Even if Cumberland could not achieve the effluent limitations through the same technology as other facilities in the category, TVA has alternative means to comply with the standards. EPA has unlawfully failed to consider any of those alternatives.

[259] Envtl. Prot. Agency, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Responses to Public Comments, EPA-HQ-OW-2009-0819-4607-A1, Comment Excerpt No. 5, 5-40 to 5-41.
[260] *Sw. Elec. Power Co.*, 920 F.3d at 1005.

Commenter Name: Bethany Davis Noll
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Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 8

Comment Excerpt:

2. New Subcategories
EPA's justifications for new subcategories for flue gas desulfurization wastewater and bottom ash transport water also rely on cost to the exclusion of other factors. EPA's entire justification for setting a separate subcategory for high flow facilities depends on one power plant in Cumberland, Tennessee, which evidently produces "an order of magnitude" more flue gas desulfurization wastewater than "other units with comparable generation capacity." [59] The plant is unable to recycle its wastewater because the plant's system is constructed with a steel alloy susceptible to corrosion.[60] Thus, EPA says, "the cost of a biological treatment system would be high," and "[p]assing these disparately higher costs on to consumers would likely put the facility at a competitive disadvantage with other coal-fired facilities."[61] The agency therefore proposes a subcategory with laxer standards for high flow facilities.

EPA's decision to create a new subcategory based on one high-polluting plant is unsupported.[62] First, if the Cumberland plant indeed releases significantly more polluting wastewater than industry standard to produce the same amount of energy, then the plant is likely not competitive and should not provide the benchmark for the "best" way to make "reasonable further progress" toward eliminating pollutants. Second, even if the Cumberland plant did not perform so poorly, it is unclear why EPA believes one plant's specific needs justify an entirely new subcategory. The agency makes no claim that the Cumberland plant is representative of a broad set of plants; nor does the agency suggest that the Cumberland plant is critical for energy reliability reasons. On the contrary, EPA's worry about competitiveness suggests that other power-producing competitors are ready to step in and serve consumers. For these reasons, the agency's decision to set a subcategory based on the report of one high-polluting plant is unsupported, violates the Clean Water Act, and is arbitrary and capricious.

EPA's analysis further violates the Clean Water Act by failing to quantitatively or qualitatively discuss the effects of setting laxer standards for plants that produce above-average amounts of polluting wastewater. Because such plants produce more waste than is typical for the industry, relaxing the BAT for these plants will have an especially significant effect on the ability of EPA to comply with its statutory mandate to make progress toward eliminating pollution discharge. Instead of considering or explaining these effects, the agency focuses only on the changes to

compliance costs. Thus, the agency violates its statutory obligation to consider whether its proposed BAT for high flow facilities is truly "best" at making progress toward eliminating pollution, or whether the BAT has an unacceptable "non-water quality environmental impact."

59 Id. at 64,638.
60 Id.
61 Id.
62 See American Paper Institute v. Train, 543 F.2d 328, 353 (C.A.D.C. 1976) (analyzing whether EPA's choice of technology standard had adequate enough record support to avoid being arbitrary and capricious).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
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Comment Excerpt:

F. The Proposed Subcategory for Units with "High Flow" FGD Systems is Unjustified.

In the 2019 Proposal, EPA proposes a high FGD flow subcategory ("High Flow Subcategory"), which would establish BAT based on chemical precipitation alone for facilities with purge flows greater than four million gallons per day.[457] The High Flow Subcategory would apply only to the Cumberland Fossil Plant ("Cumberland Plant"), a coal plant owned and operated by the Tennessee Valley Authority ("TVA"), the nation's largest publicly-owned utility.[458]

[457] 84 Fed. Reg. at 64,638.
[458] Danielle Stewart, Environmental Research Group, Alternative Flue Gas Desulfurization Treatment Costs for High Flow Plants – DCN SE07126, EPA-HQ-2009-0819-8200 (Oct. 30, 2019) ("[O]nly one plant, Cumberland (plant ID 6329), meets the requirements of this subcategory.").

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
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Although, as discussed throughout these comments, technologies exist and have long existed to remove toxic pollutants from FGD wastewater, for the better part of the past decade, TVA has sought to exempt itself from its obligation under the CWA to install modern water pollution controls at the Cumberland Plant.

During the comment period for the 2015 ELG Rule, TVA requested a less stringent subcategory for Cumberland. TVA wrote that "a uniform BAT requirement for all FGD designs is impracticable and that a subcategory or other approach for existing 'once through' and/or high-flow FGD designs is warranted."[476] TVA primarily argued that Cumberland could not achieve the ELGs because its FGD system, due to its metallurgy, would corrode if it recirculated wastewater. And TVA claimed that modifying Cumberland's scrubber material to something more corrosion resistant, or simply complying without recirculation, would be too expensive.[477] In the 2015 ELG Rule, EPA rejected these claims and denied TVA's request for a special subcategory. EPA disagreed with TVA's technical premise, finding Cumberland could recirculate some wastewater without corroding its FGD system. Moreover, EPA found its proposed BAT to be affordable for industry as a whole, as the Clean Water Act requires.[478]

Rather than complying with the 2015 ELG Rule, TVA has persisted in its efforts to seek less stringent effluent limitations for Cumberland. In April 2016, TVA applied for a Fundamentally Different Factors ("FDF") variance to exempt Cumberland from the 2015 ELGs. TVA rehashed the same arguments: Cumberland cannot recycle wastewater, so compliance would be expensive.[479] EPA never granted TVA's application,[480] and the State of Tennessee incorporated the 2015 ELGs into TVA's NPDES permit, which was reissued in 2018.[481] In TVA's comments on the draft permit, TVA expressly stated that it could comply with the 2015 ELG Rule's limits on mercury and arsenic by September 1, 2021, when the utility would complete installation of a new physical-chemical treatment system for the Cumberland Plant.[482]

Meanwhile, a coalition of industry trade groups, of which TVA is a member, had successfully petitioned the EPA to reconsider the 2015 ELG Rule.[483] TVA then lobbied EPA for special effluent limitations for Cumberland, meeting with David Ross, Assistant Administrator of the Office of Water, in September 2018, to discuss the "uniqueness of their once-through systems and the need for either an FDF [variance] or some other relief in the regulation."[484]

Since that meeting, TVA has confidently assumed that, one way or another, the Cumberland Plant will not have to comply with the 2015 ELGs. In July 2019, TVA published an Environmental Assessment for the proposed construction of FGD wastewater treatment facilities, whose purpose was "to meet the regulatory limits established by EPA's ELGs for Steam-Electric Generating Facilities."[485] The draft EA explored three alternatives, only one of which would comply with the 2015 ELG Rule. TVA's preferred alternative, and the one it ultimately selected, would lead it to violate the 2015 ELGs' restrictions on selenium and nitrate/nitrite and the terms of its current NPDES permit.[486]

The High Flow Subcategory culminates TVA's years-long campaign to receive special treatment for the Cumberland Plant.

[476] EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Responses to Public Comments, Docket ID No. EPA-HQ-OW-2009-0819-4607-A1, Comment

Excerpt No. 4, 3-583 (Sept. 2015).
[477] Id., Comment Excerpt No. 5, 5-35 to 5-38.
[478] Id. at 5-38 to 5-41.
[479] Tenn. Valley Auth., Cumberland Fossil Plant – NPDES Permit No. TN0005789 – TVA Request for Alternative Effluent Limitations for Wet Flue Gas Desulfurization System Discharges Based on Fundamentally Different Factors Pursuant to 33 U.S.C. § 1311(n) (Apr. 28, 2016) (attached).
[480] In December 2016, environmental groups, including the Southern Environmental Law Center and the Sierra Club, submitted comments to EPA Region 4 outlining the inadequacy of TVA's FDF variance application, which is attached and incorporated by reference. Letter from Amanda Garcia et al., Southern Envtl. Law Ctr., to Heather McTeer Toney, Envtl. Prot. Agency, re: TVA, Cumberland Fossil Plant – NPDES Permit No. TN0005789 – TVA Request for Alternative Effluent Limitations for Wet Flue Gas Desulfurization System Discharges Based on Fundamentally Different Factors Pursuant to 33 U.S.C. §1311(n) (Apr. 28, 2016) (Dec. 21, 2016) (attached).
[481] Tenn. Dep't Envt. & Conservation, NPDES Permit No. TN0005789 I(A)(4), at 6 (2018) (attached).
[482] Tenn. Valley Auth., Cumberland Fossil Plant – NPDES Permit No. TN0005789 – Draft NPDES Permit Comments, at 3 (May 23, 2018) ("We suggest establishing Tier limits for mercury and arsenic that would apply on September 1, 2021, or upon construction and startup of physical/chemical treatment and division approval of the initial operating period.") (attached).
[483] EPA, Proposed Rule, Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 82 Fed. Reg. 26,017, 26,018 (June 6, 2017).
[484] Email from Richard Benware to Jan Matuszko, Docket ID No. EPA HQ-2019-006928, at 61 (Sept. 12, 2018).
[485] Tenn. Valley Auth., Cumberland Fossil Plant (CUF) Wastewater Treatment Facility Final Environmental Assessment, at 5 (July 2019) (attached).
[486] Tenn. Dep't Envt. & Conservation, NPDES Permit No. TN0005789 I(A)(4), at 6 (2018) (attached). The Southern Environmental Law Center and the Sierra Club submitted comments on TVA's draft environmental assessment highlighting TVA's obligation to comply with existing law. These comments are attached and incorporated by reference. Letter from Christina Reichert et al., S. Envtl. Law Ctr., to Ashley Farless, Tenn. Valley Auth., re: Tennessee Valley Authority's Draft Environmental Assessment for the Cumberland Fossil Plant (CUF) Wastewater Treatment Facility (May 1, 2019) (attached).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
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Comment Excerpt:

1. EPA proposes a subcategory just for Cumberland.

The High Flow Subcategory would "establish a new subcategory for facilities with high FGD flows based on the statutory factor of cost."[487] In the 2019 Proposal, EPA discusses only the Cumberland Plant in the context of the High Flow Subcategory, and a memorandum from the Environmental Research Group confirms that the Cumberland Plant will be the only member of this subcategory.[488] For the FGD wastewater category, EPA proposes to establish chemical precipitation plus biological treatment as BAT.[489] In contrast, EPA proposes chemical precipitation alone as BAT for the High Flow Subcategory.[490]

Although TVA previously stated that it could comply with the 2015 ELG Rule limits on mercury by September 1, 2021, the High Flow Subcategory would allow Cumberland to discharge nearly ten times the concentration of mercury as other FGD wastewater dischargers.[491] According to

EPA, Cumberland discharges "millions of gallons per day [more] than the next highest flow rate in the entire industry."[492] EPA's proposed mercury limit coupled with its estimate of the Cumberland Plant's flows would result in the Cumberland Plant discharging over twenty times more mercury than other facilities.[493] EPA proposes no limitations for selenium or nitrate/nitrite for Cumberland.[494] The High Flow Subcategory thus shields Cumberland from the selenium and nitrate/nitrite limitations EPA proposes for the FGD wastewater category.[495]

[487] 84 Fed. Reg. at 64,638.
[488] ERG, Alternative Flue Gas Desulfurization Treatment Costs for High Flow Plants – DCN SE07126, Docket ID No. EPA-HQ-2009-0819-8200 (Oct. 30, 2019) ("[O]nly one plant, Cumberland (plant ID 6329), meets the requirements of this subcategory.").
[489] 84 Fed. Reg. at 64,631.
[490] Id. at 64,638.
[491] Id. at 64,673-74.
[492] Id. at 64,638.
[493] Consultant ERG estimates Cumberland's FGD Purge Flow as 5,142,240 gallons per day (gpd) and its Optimized FGD Flow as 4,418,898 gpd. ERG, Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings – DCN SE07091, Docket ID No. EPA-HQ-2009-0819-8200 (July 8, 2019). Those figures are more than twice as much as the next highest rates: FGD Purge Flow of 2,153,520 gpd at Big Bend Station and Optimized Purge Flow of 1,644,985 gpd at Trimble County. Id.
[494] 84 Fed. Reg. at 64,674.
[495] Id. at 64,673.

Commenter Name: Thomas Cmar
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Comment Excerpt:

2. The CWA prohibits EPA's proposed subcategory.

The High Flow Subcategory is inconsistent with the requirements of the Clean Water Act, which does not authorize a subcategory of one based on cost.

a. Subcategories of One

The text, structure, and legislative history of the Act demonstrate that BAT is a categorical, industry-wide standard. Congress created a separate mechanism, the FDF variance, for plant-by-plant determinations. Prior to codification of the FDF variance in the CWA, the Supreme Court suggested in dicta that single-member subcategories are permissible.[496] But Congress's subsequent codification of a more limited FDF variance changed the Act's structure, making clear that "Congress intended 'fundamentally different' characteristics of particular plants to be considered by the EPA in a Section 301(n) FDF variance proceeding."[497]

The Clean Water Act requires the EPA to establish "effluent limitations *for categories and classes* of point sources" by applying the "best available technology economically achievable *for such category or class*, which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[498] "[S]uch effluent limitations shall require the elimination of discharges of all pollutants if the Administrator finds . . . that such elimination is technologically and *economically achievable for a category or class of point sources* . . . ."[499] The related BAT provision requires EPA to "identify . . . the degree of effluent reduction attainable through the application of the best control measures and practices achievable . . . *for classes and categories of point sources*."[500]

In contrast to the ELG provisions' emphasis on "categories and classes," the FDF variance in the same section authorizes modifying effluent limitations "for a facility."[501] "[W]hen the legislature uses certain language in one part of the statute and different language in another, the court assumes different meanings were intended."[502] This textual distinction between "categories and classes of point sources" and "a facility" is meaningless if an individual facility can be a category.[503]

As the courts have long recognized, "Congress intended BAT limitations to be based on the performance of the single best-performing plant in an industrial field."[504] BAT only works by comparing facilities, requiring multiple plants within a category for the standard to function as designed. The BAT standard requires EPA to compare facilities across an industrial field and to set standards based on what the single best facility is doing.

The statute provides two ways to establish BAT for a facility. One is through categorical effluent limitation guidelines, "which are nationwide standards set by the EPA Administrator to govern pollutant discharges from point sources."[505] The second method is through individual FDF variances: EPA may create a less stringent, single-facility BAT for any facility that demonstrates that it is fundamentally different with respect to at least one factor EPA considered in setting BAT for the broader category or subcategory.[506] The EPA must consider the same factors for an FDF variance that it has considered for setting BAT pursuant to § 1314(b)(2)(B) – "other than cost."[507]

The two mechanisms create a distinct structure: generalized, categorical BAT standards "are to be established prior to consideration of the characteristics of the individual plant."[508]

Congress created a "coherent statutory scheme: One vehicle promulgating categorical regulations of national scope and one vehicle to address concerns relating to individual [facilities]."[509]

A subcategory of one, like the High Flow Subcategory proposed by EPA, turns BAT on its head. Rather than forcing all facilities to operate as cleanly as the single best facility, EPA would set BAT based on the single worst-polluting facility. EPA would allow Cumberland to remain the largest wastewater polluter by setting a standard lower than what any every other FGD wastewater facility must achieve. By comparing all plants to the best performers, Congress structured the BAT standard to demand improvement. "BAT must achieve 'reasonable further progress' towards the Act's goal of eliminating pollution,"[510] and EPA's proposal fails that essential requirement.[511]

[496] See *Chem Mfrs. Ass'n v. Nat. Res. Def. Council*, 470 U.S. 116, 131 (1985) ("EPA could promulgate rules . . . creating a subcategory for each source which is fundamentally different").
[497] *Chem Mfrs. Ass'n v. EPA*, 870 F.2d 177, 236 (5th Cir. 1989).

498 33 U.S.C. § 1311(b)(2)(A) (emphasis added).
499 Id. (emphasis added).
500 Id. (emphasis added). Analyzing this text, the Supreme Court has read ELGs as categorical mechanisms, in contrast with the Act's individual mechanisms like NPDES permits and FDF variances. *E.I. du Pont de Nemours & Co. v. Train*, 430 U.S. 112, 136 (1977) ("The statute thus focuses expressly on the characteristics of the 'category or class' rather than the characteristics of the individual point sources. Normally, such classwide determinations would be made by regulation, not in the course of issuing a permit to one member of the class.").
501 33 U.S.C. § 1311(n)(1).
502 Sosa v. Alvarez-Machain, 542 U.S. 692, 711 n.9 (2004).
503 The ordinary meaning of "class" or "category" implies multiple constituent members. A single plant cannot be a category or class by itself.
504 *Sw. Elec. Power Co. v. EPA,* 920 F.3d 999, 1018 (5th Cir. 2019) (quoting *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 226 (5th Cir. 1989)); see also *Kennecott v. EPA*, 780 F.2d 445 (4th Cir. 1985) ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible.").
505 *Sw. Elec. Power Co. v. EPA*, 920 F.3d at 1005.
506 33 U.S.C. § 1314(n)(1)(A).
507 Id.
508 *Du Pont*, 430 U.S. at 127 n.17. See also *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 939 (5th Cir. 1998) ("We agree that Congress intended to foreclose plant-by-plant evaluation of facilities within a subcategory.").
509 *Chem. Mfrs. Ass'n v. EPA,* 870 F.2d at 259. The Fifth Circuit panel was discussing the structural relationship of the pretreatment standards (categorical) with removal credits provision (plant-by-plant) but expressly compared that structure to the "FDF variance scheme discussed above" – about which the court stated that "Congress intended 'fundamentally different' characteristics of particular plants to be considered by the EPA in a Section 301(n) FDF variance proceeding." Id. at 236.
510 *Sw. Elec. Power Co.*, 920 F.3d at 1006.
511 See *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 236 (rejecting industry request for a single-plant subcategory and finding that setting BAT in a national rulemaking based on a single plant's characteristics conflicts with the structure Congress created).

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Comment Excerpt:

b. The Act Prohibits EPA from Creating Single-Facility, Cost-Based BAT Subcategories.

Even if a subcategory of one were permissible, which it is not, a subcategory of one based on cost is flatly inconsistent with the Clean Water Act.

The costs of an individual facility are not relevant in setting BAT. The Act requires BAT to be "economically achievable for a category or class of point sources."[512] As the 1972 conference report explains, Congress directed EPA to "make the determination of the economic impact of an effluent limitation on the basis of classes and categories of point sources, as distinguished from a plant-by-plant determination."[513] Courts have consistently found that BAT "does not refer to any individual plant" in assessing economic achievability.[514]

Congress structured the Clean Water Act to prohibit EPA from setting effluent limitations for toxic pollutants[515] based on an individual facility's costs. BAT sets effluent limitations based on industry-wide costs, not individual facility costs.[516] Section 301(c) modifications allow EPA to modify an individual facility's effluent limitations based on facility-specific costs.[517] But Congress prohibited such modifications for toxic pollutants, like those at issue here.[518] The FDF variance allows individual accommodation based on any factor "other than cost."[519] FDF variances are unavailable here because cost is the only factor EPA cites to support subcategorization.

Legislative history confirms that the Act does not authorize EPA to create single-facility, cost-based BAT subcategories.

When codifying the FDF variance, Congress reiterated its intent to prohibit single-facility, cost-based subcategories. Regarding the FDF variance, the 1986 conference report stated, "The bill specifically excludes consideration of costs, independent of other eligible factors, as a basis for establishing a fundamental difference with regard to an individual facility."[520]

Senator Robert Stafford (R-VT), Chairman of the Environment and Public Works Committee and a member of the conference committee, explained:

If a facility faces higher individual cost than the industry average, that is a reflection of economic efficiency of the facility rather than the ability of the industry as a whole to meet the necessary pollution control costs. To establish individual effluent limits on the basis of plant-specific cost of compliance would be to vitiate the principle of industrywide minimum treatment levels. For these reasons . . . the conferees agreed to adopt the Senate approach and exclude the individual cost of compliance from the factors the Administrator may consider when deciding whether to grant an FDF variance to a particular facility. Although *the act does not and should not provide a mechanism to modify the requirements of an effluent guideline on the basis of fundamentally different costs at an individual facility*, section 301(c) of the act provides for modification of requirements in a case where such requirements are beyond the economic capability of the owner. . . . In addition, section 301(c) is subject to section 301(l), which prohibits the Administrator from modifying any requirement as it applies to a toxic pollutant. *This provision assures that toxic pollutants will be controlled, regardless of the economic capability of the discharger*.[521]

In short, the Clean Water Act does not authorize EPA to make single-plant, cost-based exceptions to effluent limitations for toxic pollutants, as EPA proposes to do in the High Flow Subcategory.

[512] 33 U.S.C. § 1311(b)(2)(A).
[513] Sen. Rep. No. 92-1236, at 121 (1972) (Conf. Rep.).
[514] *Du Pont*, 430 U.S. at 127 n.17. The Supreme Court pointed to 33 U.S.C. § 311(c), which allows modification of BAT limitations for a facility if "such modification requirements (1) will represent the maximum use of technology within the economic capability of the owner or operator; and (2) will result in reasonable further progress toward the elimination of the discharge of pollutants." The Court explained, "This provision shows that the [33 U.S.C. § 1311(b)] limitations for 1983 are to be established prior to consideration of the characteristics of the individual plant. Moreover, it shows that the term 'best technology economically achievable' does not refer to any individual plant. Otherwise, it would be impossible for this 'economically achievable' technology to be beyond the individual

owner's 'economic capability.'" *Du Pont,* 430 U.S. at 127 n.17 (internal citation omitted). See also *Texas Oil & Gas Ass'n*, 161 F.3d at 928 ("[I]n promulgating ELGs the EPA must set discharge limits that reflect the amount of pollutant that would be discharged by a point source employing the best available technology that the EPA determines to be economically feasible across the category or subcategory as a whole."); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 219 n.157 ("Congress intended that economic impacts be determined only for classes of facilities, rather than on a plant-by-plant basis. 118 Cong.Rec. 33758 (1972), 1972 Leg. Hist. at 255, 304.").
[515] Arsenic, mercury, and selenium are toxic pollutants for purposes of setting BAT. See 33 U.S.C. § 1317(a)(1) (requiring EPA to publish list of toxic pollutants); § 1317(a)(2) (requiring EPA to set BAT for listed toxic pollutants); 40 C.F.R. § 401.15 (listing arsenic, mercury, and selenium as toxic pollutants pursuant to 33 U.S.C. § 1317(a)(1)).
[516] *Du Pont*, 430 U.S. at 127 n.17. See also EPA v. *Nat'l Crushed Stone Ass'n*, 449 U.S. 49, 79 (1980) ("Congress foresaw and accepted the economic hardship, including the closing of some plants, that effluent limitations would cause; and Congress took certain steps to alleviate this hardship . . . ").
[517] 33 U.S.C. § 1311(c).
[518] Compare id. ("The Administrator may modify the requirements of subsection (b)(2)(A) of this section with respect to any point source for which a permit application is filed after July 1, 1977, upon a showing by the owner or operator of such point source satisfactory to the Administrator that such modified requirements (1) will represent the maximum use of technology within the economic capability of the owner or operator; and (2) will result in reasonable further progress toward the elimination of the discharge of pollutants.") with id. § 1311(l) ("Other than as provided in subsection (n) of this section, the Administrator may not modify any requirement of this section as it applies to any specific pollutant which is on the toxic pollutant list under section 1317(a)(1) of this title.").
[519] Id. § 1314(n)(1)(A). Section 301(g) provides another mechanism to modify ELGs for individual facilities, but 301(g) modifications are likewise barred for toxic pollutants. Id. § 1311(g)(4)(a).
[520] H.R. Rep. No. 99-1004, at 123 (1986) (Conf. Rep.).
[521] 132 Cong. Rec. S16,426 (daily ed. Oct. 16, 1986) (statement of Sen. Stafford) (emphasis added).

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Commenter Affiliation: Earthjustice et al.
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Comment Excerpt:

3. EPA has no reasoned basis for its policy shift in establishing the High Flow Subcategory.

In the 2015 ELG Rule, EPA rejected both a high flow subcategory and the use of chemical precipitation alone to establish BAT. The EPA has provided no reasoned basis for its policy reversal.

a. The High Flow Subcategory Is an Unexplained Reversal.

EPA proposes a subcategory for "facilities with high FGD flows based on the statutory factor of costs."[522] EPA explains, "Based on the typical chloride concentrations in the FGD scrubber, the facility would be able to recycle little, if any, of the wastewater back to the scrubber as a means for reducing the flow volume sent to a treatment system. . . . [A]s a result of the inability to recycle these high flows, TVA stated that the cost of a biological treatment system would be high."[523] EPA takes TVA at its word, justifying the subcategory on that basis.

But in 2015, EPA considered and rejected doing exactly what it now proposes. TVA had argued that "a uniform BAT requirement for all FGD designs is impracticable and that a subcategory or other approach for existing 'once through' and/or high-flow FGD designs is warranted."[524] TVA asserted that the FGD systems' metallurgy at certain facilities, including Cumberland, could not achieve the flow minimization EPA presumed.[525] The result is that "facilities with 'once-through' and/or high-flow FGDs would unfairly bear the brunt of the industry's cost to treat to comply with the ELGs."[526]

In 2015, EPA disagreed. The agency found that the FGD wastewater BAT, chemical precipitation plus biological treatment, was "achievable and affordable for the industry as a whole."[527] Finding high FGD flow wastewater characteristics to be "within the same range" as other facilities in the category, EPA declined to create a high FGD flow subcategory.[528] EPA cited the "variability of FGD wastewater flow rates at plants," which could incentivize plants to discharge more wastewater to become part of the less stringent subcategory.[529] The scenario would likely lead to "an increase in intake water, which is non-water quality environmental impact" and "an increase in wastewater discharge volumes and potentially no reduction in pollutant loadings, which would not result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[530]

In the 2015 ELG Rule, EPA considered and rejected TVA's arguments that Cumberland's FGD system metallurgy prohibited compliance with the BAT limitations due to corrosion and operational concerns. EPA found that the Cumberland FGD system could tolerate higher concentrations of chloride than TVA stated would be possible, thus allowing for increased wastewater recirculation.[531] Highlighting several options for wastewater recycling, EPA emphasized that "plants are not required to install or operate a certain FGD wastewater treatment technology to meet the final ELG's [sic]."[532]

The only new information EPA cites for the policy shift is a brief email, in which TVA provides "preliminary estimates [of compliance costs] with an accuracy of -30% to +50%."[533] EPA has not addressed its 2015 findings that a high FGD flow subcategory would create incentive to discharge more wastewater and result in related non-water quality environmental impacts of increased intake water. Facing the same arguments TVA presented in 2015, and with essentially the same data, EPA reaches the opposite conclusion. Yet EPA fails to explain the inconsistencies of doing so.

[522] 84 Fed. Reg. at 64,638.
[523] Id.
[524] EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Responses to Public Comments, Docket ID No. EPA-HQ-OW-2009-0819-4607-A1, Comment Excerpt No. 4, 3-583 (Sept. 2015).
[525] Id., Comment Excerpt No. 5, 5-35.
[526] Id., Comment Excerpt No. 4, 3-584.
[527] Id. at 3-585.
[528] Id. at 3-586.
[529] Id.
[530] Id.
[531] Id. at 3-587.
[532] Id., Comment Excerpt No. 5, 5-40 to 5-41.

[533] See Email from Carolyn Koroa, Tenn. Valley Auth.,to Anna Wildeman, EPA (Nov. 13, 2018) - DCN SE08195, Docket ID No. EPA-HQ-OW-2009-0819-8276.

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 140

Comment Excerpt:

b. EPA Proposes a BAT It Previously Rejected as Inadequate.

EPA unlawfully proposes a BAT that it previously rejected as inadequate. EPA proposes chemical precipitation alone as BAT for high FGD flow facilities.[534] But in 2015, EPA rejected chemical precipitation as BAT. The agency found chemical precipitation was "not effective at removing selenium, nitrogen compounds, and certain metals that contribute to high concentrations of TDS in FGD wastewater."[535] Discharging those pollutants "caus[es] adverse human health impacts and some of the most egregious environmental impacts."[536] EPA therefore "determined that, by itself, chemical precipitation would not result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants (see CWA section 301(b)(2)(A)), and rejected that technology basis as BAT."[537]

In the 2019 Proposal, EPA does not explain or acknowledge important inconsistencies created by its policy reversal: How can a technology EPA once rejected as inadequate become the best available technology more than four years later? Does EPA still expect human health impacts and egregious environmental impacts from pollutants discharged in wastewater treated only by chemical precipitation? Most importantly, does chemical precipitation alone result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants? EPA's proposed rule is arbitrary and capricious because it fails to explain or even acknowledge these critical inconsistencies. Instead, EPA relies solely on cost to explain its proposal.

[534] 84 Fed. Reg. at 64,638.
[535] 80 Fed. Reg. at 67,851.
[536] Id.
[537] Id. at 67,852.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 144

Comment Excerpt:

b. EPA Relies on an Irrelevant Factor and Ignores Statutory Factors.

EPA improperly considered the costs of a single facility in setting BAT for the High Flow Subcategory. BAT must be economically achievable, but "Congress intended that economic impacts be determined for classes of facilities, rather than on a plant-by-plant basis."[547] The Act's structure and legislative history show that Congress intended to prohibit EPA from setting effluent limitations for toxic pollutants based on an individual facility's costs.[548] And while industry-wide costs are relevant in setting BAT, they are of secondary importance.[549] Allegedly disproportionate costs for a single facility are not a legitimate factor for setting BAT, which "represents a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges."[550] By justifying BAT for toxic pollutants solely based on Cumberland's relatively high compliance costs, "the agency has relied on factors which Congress has not intended it to consider."[551]

EPA ignored BAT's express statutory factors. To justify a BAT subcategory, a class of facilities must be fundamentally different with respect to the factors listed in 33 U.S.C. § 1314(b)(2)(B).[552] "Although the EPA has significant discretion in deciding how much weight to accord each statutory factor under the CWA, it is not free to ignore any individual factor entirely. Both the CWA, 33 U.S.C. § 1314(b)(2), and the EPA's own regulations, 40 C.F.R. § 125(c)-(d), state that the EPA *shall* take into account (or apply) certain factors in making a BAT determination . . . ."[553] Those factors include "the engineering aspects of the application of various types of control techniques, process changes, [and] non-water quality environmental impact." 33 U.S.C. § 1314(b)(2)(B). In the High Flow Subcategory, EPA has ignored every factor but cost. Nowhere does EPA address the non-water quality environmental impacts, despite the agency's 2015 refusal to create a high FGD flow subcategory partly because of the potential "increase in intake water, which is non-water quality environmental impact that EPA is required to consider under section 304(b) of the Clean Water Act."[554] EPA's failure to consider relevant statutory factors is arbitrary and capricious.

Even if EPA had considered the BAT factors, not one supports subcategorization. TVA has argued against complying with the 2015 ELG Rule based on non-water quality impacts, process changes, and engineering aspects of the application of the 2015 BAT. TVA has argued that changing its FGD wastewater pollution control technology would "risk air compliance impacts."[555] But other plants meet their equally stringent air compliance obligations while also recycling FGD wastewater. TVA has cited concerns of increased mercury in the gypsum it markets.[556] Not only is that concern unsupported by any evidence, but protecting the economic viability of a marketing program is not a reason the Clean Water Act contemplates for relaxing effluent limitations.[557] TVA has stated that recirculation "increases the complexity of wastewater which reduces its ability to be treated."[558] But other facilities overcome this same "complexity," which is present in all FGD recirculated wastewater. And as EPA found in 2015, the Cumberland Plant's FGD system metallurgy can recirculate wastewater without corroding. TVA has acknowledged the system's ability to accept up to 3,175 ppm chloride, a level sufficient to increase FGD wastewater recirculation without causing corrosion.[559] Finally, because TVA's average generation at the Cumberland Plant is much lower than EPA assumes, for the vast majority of the time the Cumberland Plant's actual flow rates are less than 4 mgd – the threshold EPA has established for the High Flow Subcategory – without any changes at all to how the units are operating.[560] In summary, the facts show that the sole plant for which EPA proposes the High Flow Subcategory does not require subcategorization.

[547] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 219 n.157.
[548] See Section X.F.2 - The Act Prohibits EPA's Proposed Subcategory.
[549] See Am. Iron and Steel Inst. v. EPA, 526 F.2d 1027, 1052 n.51 (3d Cir. 1975) ("[I]t is clear that for 'BATEA' standards, cost was to be less important than for the 'BPCTCA' standards, and that for even the 'BPCTCA' standards cost was not to be given primary importance.").
[550] *Nat'l Crushed Stone*, 449 U.S. at 74.
[551] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983).
[552] *Citizens Coal Council v. EPA*, 447 F.3d 879, 893 (6th Cir. 2006).
[553] T*exas Oil & Gas Ass'n*, 161 F.3d at 934. See also *Sw. Elec. Power Co*., 920 F.3d at 1006 ("[T]he Act lists factors the Administrator must consider in determining BAT.").
[554] EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Responses to Public Comments, Docket ID No. EPA-HQ-OW-2009-0819-4607-A1, Comment Excerpt No. 4, 3-586 (Sept. 2015).
[555] Tenn. Valley Auth., Cumberland Fossil Plant (CUF) Wastewater Treatment Facility Final Environmental Assessment, at 12 (July 2019) (attached).
[556] Id.
[557] In 2019, TVA reported to its state regulator that it was acquiring the wallboard facility to which it previously marketed its gypsum. Tenn. Valley Auth., Wet FGD Wastewater Treatment and Bottom Ash ELG Project Updates, Cumberland Fossil Plant, NPDES Permit No. TN0005789, Annual Report 2018 (Jan. 24, 2019) (attached).
[558] Id.
[559] Sahu Expert Report at 43.
[560] Id. at 48.

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 145

Comment Excerpt:

c. EPA Ignores Reasonable Alternatives.

EPA unlawfully fails to consider any alternatives. Under all four options EPA considered, BAT for the High Flow Subcategory is chemical precipitation.[561] There are numerous available technologies EPA refused to consider for high FGD flow facilities, including various combinations of chemical precipitation, biological treatment (high- or low-residence time), membrane technology, thermal technology. EPA's failure is particularly egregious because the agency failed to evaluate a single alternative – despite a congressional mandate to find the "best available technology economically achievable."

[561] See 84 Fed. Reg. at 64,630.

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Comment Excerpt:

Similarly, in proposing the High Flow Subcategory, EPA fails to consider Cumberland's alternatives for meeting the same standard as other facilities. Assuming Cumberland's scrubber metallurgy prevents compliance with the FGD wastewater category's BAT (a position EPA rejected in 2015), TVA could modify its scrubber materials or line its absorbers to increase resistance to corrosion. TVA could replace some or all high sulfur coal with low sulfur and low chlorine sub-bituminous Powder River Basin coal at Cumberland. As EPA informed TVA in 2015, "plants are not required to install or operate a certain FGD wastewater treatment technology to meet the final ELG's."[562] EPA now assumes that BAT mandates a single technology, arguing that Cumberland's inability to implement that technology justifies special treatment. Erroneously ruling out one existing technology for one plant does not justify weakening BAT, a "technology-forcing" standard Congress created "to press development of new, more efficient and effective pollution-control technologies."[563] Even if Cumberland could not achieve the effluent limitations through the same technology as other facilities in the category, TVA has alternative means to comply with the standards. EPA has unlawfully failed to consider any of those alternatives.

[562] EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Responses to Public Comments, EPA-HQ-OW-2009-0819-4607-A1, Comment Excerpt No. 5, 5-40 to 5-41.
[563] *Sw. Elec. Power Co. v. EPA*, 920 F.3d at 1005.

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Comment Excerpt Number: 147

Comment Excerpt:

d. EPA Paradoxically Endorses and Rejects the Same Technology as BAT.

Setting chemical precipitation as BAT, despite rejecting it elsewhere as inadequate, is arbitrary and capricious. In 2015, EPA found that chemical precipitation would not result in reasonable further progress.[564] Consistent with that finding, EPA's current proposal rejects the chemical precipitation as BAT for the FGD wastewater category, partly because chemical precipitation inadequately reduces discharges of pollutants, including selenium and nitrate/nitrite.[565] EPA's "paradoxical action" –selecting chemical precipitation as BAT, while rejecting it as inadequate elsewhere – "signals arbitrary and capricious agency action."[566] Further, "EPA has contravened the plain language of the CWA, which defines BAT as the technology that '*will result* in reasonable further progress' toward pollutant discharge elimination."[567]

[564] 80 Fed. Reg. at 67,852.
[565] 84 Fed. Reg. at 64,632.

[566] *Sw. Elec. Power Co*., 920 F.3d at 1016.
[567] Id. (emphasis original).

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Comment Excerpt:

Section 4 - High FGD Flow Subcategory

4.1 Introduction

In its November 22, 2019 proposal to revise the ELGs for steam electric power plants, EPA is proposing a subcategory for "facilities" with high FGD flows[97] based on "the statutory factor of cost." In reality, as explained in the docket, this subcategory would only apply to a single facility – namely TVA's Cumberland Fossil Plant.[98] As described in the preamble99 and the accompanying TDD, TVA has requested relief from meeting the 2015 ELG standards for FGD wastewater (i.e., daily maximum and 30-day average limits) for at least selenium and nitrate/nitrite, arguing that the biological treatment system needed to comply with at least these two pollutants would be very expensive. This is in part, TVA argues, because its FGD systems (two, each treating flue gases from each of Units 1 and 2 at the plant) are a "once-through" design with large FGD flows.[100] TVA has claimed that due to the type of steel used in the FGD absorber, it cannot recycle FGD wastewater since the absorbers[101] cannot handle chloride levels greater than 3,000 ppm.[102]

EPA has proposed to subcategorize facilities with FGD purge flows greater than four million gallons per day (MGD),[103] after accounting for that facility's ability to recycle the wastewater to the maximum limits for the FGD system materials of construction. According to EPA, only the Cumberland plant would fall into this subcategory. EPA states that "…[s]uch a flow [meaning the 4 MGD] reflects the reasonably predictable flow associated with actual and expected FGD operations."[104] According to TVA, the cost to meet the 2015 ELG (i.e., using chemical precipitation and biological treatment) at Cumberland would result in a capital cost of $171 million, and an operating and maintenance (O&M) cost of approximately $20 million per year.[105] As EPA admits in the preamble, its own projected costs "…are even higher than TVA's (a $256 million dollar capital cost plus $21 million per year in O&M)." Based on these projected costs, "…EPA proposes to establish BAT based on chemical precipitation alone, with effluent limitations for mercury and arsenic."[106]

I disagree with EPA's proposal for a subcategory just for this one plant. For the reasons stated below, I believe that EPA's analysis is premature, unsupported by publicly available data, and incomplete. There are many options available to TVA to deal with its Cumberland FGD flow, including zero discharge, that EPA has not explored in this proposal. My comments are based on the proposal, documents in the docket and TVA's public submittals including:

- The 2016 Variance Request (hereafter "Variance Request"). Tennessee Valley Authority (TVA) — Cumberland Fossil Plant—NPDES Permit No. TN0005789—TVA Request for Alternative Effluent Limitations for Wet FGD System Discharges Based on Fundamentally Different Factors Pursuant to 33 U.S.C. 1311(n). April 28, 2016.[107]
- Cumberland Fossil Plant (CUF) Wastewater Treatment Facility Environmental Assessment (hereafter "EA"), Draft April 2019[108] and Final (July 2019).[109]

4.2 Cumberland Plant and TVA's Rejection of Compliance Options

Cumberland Fossil Plant (abbreviated as "CUF" by TVA), is located on the shores of Barkley Reservoir in Cumberland City, Tennessee. The two-unit plant has a maximum rated gross output of 2,470 megawatts.[110] As noted earlier each unit is equipped with a SO2 removal scrubber for FGD.

From the very beginning of EPA's ELG rule-making, CUF has claimed that it cannot comply with the 2015 ELG requirements, specifically the selenium and nitrate/nitrite limits, because the scrubbers at CUF are once-through, high flow type scrubbers.[111] Instead, as noted previously, in 2016 it asked for the Fundamentally Different Factors (FDF) Variance from the ELG limits via a request letter/report to the Tennessee Department of Environment and Conservation (TDEC) and EPA.[112] In its Variance Request in 2016, TVA rehashed arguments it made to EPA during development of the 2015 ELG Rule arguing for separate standards for once-through and/or high-flow scrubber units like CUF. TVA's main point of contention is that, given the age of the CUF scrubbers and the materials of construction, it cannot use recirculation because that would increase the chloride concentration in the absorber to the point of increasing corrosion. And, per TVA, changing the scrubber material to more corrosion resistant steel and/or non-metallic materials and/or lining the absorber with appropriate materials would be cost prohibitive.[113]

Contrary to its current proposal, EPA considered TVA's arguments and rejected them during the 2015 rulemaking.[114]

In its 2019 draft and final EAs, TVA repeats its previous arguments and rejects potential options for compliance with the 2015 ELG Rule,115 as I excerpt below: First, rejecting options to reduce flow volume, the main driver of treatment costs, TVA states the following:

…The design maximum chlorides concentration at CUF is approximately 3000 milligrams per liter (mg/L). In order to convert CUF WFGD to a recycle scrubber to reduce volume, significant upgrades to the materials of construction would be needed for the WFGD absorbers to withstand higher allowable concentrations of chlorides. During the preliminary phase of WFGD WWT, TVA considered lining scrubber components to withstand up to 8,000 – 12,000 mg/L chlorides but conversion to a recycle scrubber was eliminated from further evaluation for several reasons. Scrubber operation using the current once-through design has been very successful for more than 23 years and TVA is reluctant to risk air compliance impacts by changing processes that work. In addition to compliance risk, there is increased corrosion risk for recycle scrubbers that could negatively impact WFGD reliability.

Recycling effluent can also potentially increase mercury in the gypsum which could cause the wallboard marketer to reject the material. As TVA avoids significant landfill space requirements and disposal risks because of its successful gypsum marketing program at CUF, it wants to protect that marketing program.

Another risk in conversion to a recycle scrubber is that according to Electric Power Research Institute (EPRI), WFGD WWT for mercury at higher total dissolved solids may not be as effective. Testing by EPRI has confirmed that increasing dissolved constituents increases the complexity of the wastewater which reduces its ability to be treated. This appears to be because as one increases Flue-gas Desulfurization (FGD) recycle, the soluble (and/or small particulate) mercury increases and effectiveness of chemical precipitation of mercury deteriorates, making it more difficult to achieve the final ELGs for mercury.

Treatment using membrane technology and brine encapsulation would necessitate similar volume reduction and process changes and were considered as part of this evaluation and are not being pursued further."[116] (emphases added)

Next, rejecting recycling even up to 3,000 ppm of chlorides, its current limit based on the materials of construction of its scrubbers, TVA states:

Another alternative considered but eliminated from further consideration would be to recycle the treated wastewater back to the WFGD only up to the chloride's limits imposed by the current materials of construction, or 3000 mg/L. Although there are times that WFGD blowdown occurs and the chlorides levels are lower, this alternative was eliminated from further consideration because the chlorides concentrations in the WFGD absorber modules are variable. When chlorides concentrations exceed 3000 mg/L, there would be no volume reduction because the returned purge stream would already be at the limit for chlorides in the WFGD and would have to be discharged. Additionally, working with higher chlorides values due to a partial recycle could cause corrosion of components.

In addition, controlling the recycling of treated wastewater back to the WFGD based on chlorides adds complexity to the process controls. There would be six individual modules (three modules per each WFGD absorber) to control for chlorides concentration and variability between modules can be high….[117] (emphases added)

My response to TVA's statements above, especially the ones I have emphasized is as follows:

In its discussions in the EA, TVA provides no support for its statements above, and it appears that none exists. For example, it is not clear why TVA would risk air compliance obligations if it increased the recycle of FGD wastewater – like every other FGD at every coal plant where operators are able to meet their equally stringent (if not more so) air compliance obligations with low FGD purge rates due to high recycle. It is not clear what "risk" TVA is afraid of. Next, TVA speculates that there could be increases in the mercury content of the gypsum that it sells and that it wants to "protect" that marketing program. Not only is this claim speculative and presented with no supporting data, protection of its marketing program at the cost its ELG compliance is not and should not be a factor that EPA should consider. In any case, it is my understanding based on TVA's own statements to its regulator that TVA has recently is acquiring or has acquired the gypsum wall board customer so this is no longer a marketing program.[118] Similarly, TVA speculates, citing vaguely to EPRI (but without reference to any specific EPRI document) that wastewater "complexity" may increase and that may "reduce its ability to be treated." Such "complexity" is present in every wet FGD system and FGD wastewater and other operators are able to deal with it and treat it. With regards to membrane filtration TVA summarily dismisses their application with no technical basis at all. I note that EPA has costed its alternative treatment for Cumberland using membranes[119] – and rightly so given their ready availability and no hinderance to their technical feasibility – so TVA's rejection of this technology is simply unacceptable. Next, TVA cites to variability in chloride concentrations as a factor in its inability to increase recycle rates. It is not clear what TVA means. If each of the modules can accept up to 3,000 ppm chlorides (or, rather 3,175 ppm, as I note earlier citing to TVA itself), it is entirely technically feasible to increase recycle purge rates so that chloride levels at any of the absorbers can rise to this level without causing corrosion. Lastly, TVA cites vaguely and without explanation the "complexity" of "process controls" as a reason for its inability to consider recycling. This is again contrary to the experience of most other coal plant operators who operate wet FGD systems. In summary, none of TVA's arguments have any technical merit or support. Instead, these baseless assertions indicate that TVA does not want to seriously consider any volume reduction options.

EPA, in its current proposal, is simply allowing, via subcategorization, to let TVA achieve what it requested in its variance, using cost as an excuse. But EPA's cost analysis is flawed resulting in inflated FGD wastewater treatment costs.

97 84 Fed. Reg. at 64,638.

98 "Based on the methodology for estimating FGD wastewater flow rates, as described in the Flue Gas Desulfurization Flow Methodology (DCN SE07091), only one plant, Cumberland (Plant ID 6329), meets the requirements for this subcategory." ERG Memorandum Re: Alternative Flue Gas Desulfurization Treatment Costs for High Flow Plants – DCN SE07126 (Oct. 30, 2019) (EPA-HQ-OW-2009-0819-8200).

99 "The 2015 rule discussed the ability of high-flow facilities to recycle FGD wastewater back into the air pollution control system to decrease FGD wastewater flows and treatment costs. After the 2015 rule, the Tennessee Valley Authority (TVA) submitted a request seeking a fundamentally different factors (FDF) variance for its Cumberland power facility. This variance request relied primarily on two facts. First, TVA stated that Cumberland's FGD wastewater flow volumes are several million gallons per day, approximately an order of magnitude higher than many other units with comparable generation capacity, and millions of gallons per day higher than the next highest flow rate in the entire industry. TVA further stated that the FGD system at Cumberland is constructed of a steel alloy that is susceptible to chloride corrosion. Based on the typical chloride concentrations in the FGD scrubber, the facility would be able to recycle little, if any, of the wastewater back to the scrubber as a means for reducing the flow volume sent to a treatment system. Second, as a result of the inability to recycle these high flows, TVA stated that the cost of a biological treatment system would be high." 84 Fed. Reg. 64,638.

100 Since the FGDs are once-through, it is more appropriate to call the FGD wastewater flows simply that as opposed to "purge" flows.

101 Each of the two FGDs at Cumberland has 3 absorbers. Tenn. Valley Auth., Cumberland Fossil Plant—NPDES Permit No. TN0005789—TVA Request for Alternative Effluent Limitations for Wet Flue Gas Desulfurization System Discharges Based on Fundamentally Different Factors Pursuant to 33 U.S.C. § 1311(n), at 15 (Apr. 28, 2016) ("Variance Request").

102 Since TVA's asserted inability to limit chloride levels based on the current materials of construction of Cumberland's FGD absorbers is an assumption underpinning EPA's proposal to subcategorize just this plant, it is worth noting that TVA, in its 2016 Variance request states that its chloride limits is 3,175 ppm. (Variance Request, Attachment 1, Appendix 1).

103 ERG Memorandum Re: Alternative Flue Gas Desulfurization Treatment Costs for High Flow Plants – DCN SE07126 (Oct. 30, 2019) (EPA-HQ-OW-2009-0819-8200). Four (4) MGD corresponds to 2778 gallons per minute (gpm) assuming continuous (i.e., 24-hour) and uniform flow.
104 84 Fed. Reg. 64,638.
105 Per TVA, "[t]he construction estimate for Physical/Chemical treatment is approximately $70M, and the estimated annual Operation and Maintenance (O&M) for operation of that treatment is approximately $4.5M. To add biological treatment, the construction cost is estimated to be $101M and the estimated annual O&M costs are approximately $15M." Email of Carolyn Koroa, TVA, to Anna Wildeman, EPA, Re: Cost Estimates for Wastewater Treatment (Nov. 13, 2018) (EPA-HQ-OW-2009-0819-8276).
Regarding costs, I note that in the 2016 Variance request, TVA stated that: "At TVA's request, our consulting engineers, HDR Engineering, provided an order-of-magnitude cost estimate for wet FGD wastewater treatment at Cumberland based on a design flow rate of 5,187 gpm. (citation omitted) HDR's installed cost estimate is $205 million for chemical precipitation and biological treatment at Cumberland. Approximately $124 million, representing 60% of Cumberland's total installed costs, is estimated for the biological portion of these costs." Variance Request at 19-20.
106 I note that TVA, based on an NEPA Environmental Assessment (EA) prepared in 2019, appears to be proceeding to install a pre-treatment (Stage A) and a chemical precipitation system (Stage B of its proposed 3-Stage treatment system). If EPA finalizes this proposal, TVA would not need to install Stage C, the biological treatment system for removal of nitrate/nitrite and selenium.
107 See generally Variance Request.
108 See TVA, Cumberland Fossil Plant (CUF) Wastewater Treatment Facility Draft Environmental Assessment (Apr. 2019) , available at
https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/Environmental%20Reviews/Cumberland%20Fossil%20Plant%20Wastewater%20Treatment%20Facility/ea_tva_cuf_wwtf_draft_ea.pdf.
109 TVA, Cumberland Fossil Plant (CUF) Wastewater Treatment Facility Final Environmental Assessment (Jul. 2019), available at
https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/Environmental%20Reviews/Cumberland%20Fossil%20Plant%20Wastewater%20Treatment%20Facility/Final%20EA_CUF%20WWTF_2019-0705.pdf.
110 TVA, Cumberland Fossil Plant, available at https://www.tva.gov/Energy/Our-Power-System/Coal/CumberlandFossil-Plant.
111 High flows from the CUF scrubbers, in TVA's view, make biological controls which are needed to meet the selenium limits in the final ELG Rule, too expensive. TVA does not want to install these biological controls.
112 See generally Variance Request. In the Variance Request, TVA does not specify any alternate limits it would meet. Instead, it describes a process by which such an unspecified standard might be determined at an unspecified time in the future.
113 TVA makes a few other arguments such as potentially increased abrasion due to increased solids content if recirculation is to be used – but it provides so little technical support for these non-chloride arguments that they are meaningless. Instead, they should be given little to no weight. They appear to be part of a TVA strategy to simply throw whatever might stick.
114 See EPA Response to Comments Effluent Limitations Guidelines (ELG) and Standards for the Steam Electric Power Generating Point Source Category, Part 3 of 10, at 3-583 to 3-587 (Sept. 2015). See also EPA responses to related comments by others at 3-589 to 3-590.
115 See EA, Section 2.2
116 See EA, Section 2.2.1.
117 See EA, Section 2.2.3.
118 TVA, Wet FGD Wastewater Treatment and Bottom Ash ELG Project Updates, Cumberland Fossil Plant, NPDES Permit No. TN0005789, Annual Report 2018 (Jan. 24, 2019).
119 See ERG Memorandum Re: Alternative Flue Gas Desulfurization Treatment Costs for High Flow Plants – DCN SE07126 (Oct. 30, 2019) (EPA-HQ-OW-2009-0819-8200).

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Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 33

Comment Excerpt:

4.3 EPA's Costs Are Inflated Because It Does Not Properly Consider Significant Volume Reduction Options

Since EPA bases its subcategory proposal on cost considerations,[120] it is surprising that EPA did not conduct a more thorough assessment of additional options to reduce capital and O&M costs beyond assuming that a modest volume reduction is possible by enabling a small amount of recycle, while still staying below the 3,000 ppm chloride level for the absorbers.

The volume (or flow rate) of FGD water is a major driver[121] of costs – both capital and operating. In fact, all of EPA's costs for FGD wastewater treatment are based on cost-curves that rely on FGD purge flow rate as the one and only input for calculating costs.[122]

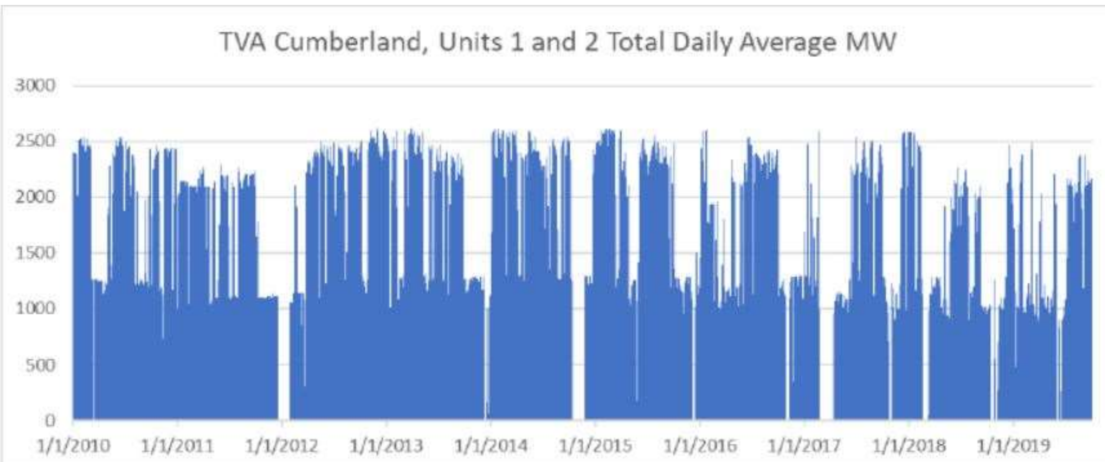
Therefore, EPA should have, logically, explored all of the possible ways TVA can and should reduce FGD wastewater volume at Cumberland. But it has not done so.

First, glaringly absent in TVA's analysis of its options to reduce its wastewater flow rate (and thereby dramatically increase its recycle rate) is the use of low sulfur (and low chlorine) subbituminous Powder River Basin (PRB) coal at Cumberland. Rather than continuing the use of its current high sulfur (and high chlorine) bituminous coal blends, TVA could replace and or blend in PRB coals in order to reduce the chloride content of the coal feed to each unit and thus the chloride content in the scrubber absorber to the point where the chloride content, even with recirculation, would be well below the corrosion threshold of the current absorbers (i.e., stay below than 3,175 ppm). However, TVA does not discuss this coal substitution (or even coal blending) option in any of its documents, including the 2016 Variance Request, the EA, or any recent correspondence with EPA at all.[123] Neither does EPA. To see the potential benefits of this approach, I examine the chlorine levels of TVA's current coals/blends at Cumberland. In Appendix 3 of its variance request, TVA states the chlorine levels of its coals/blends as follows:

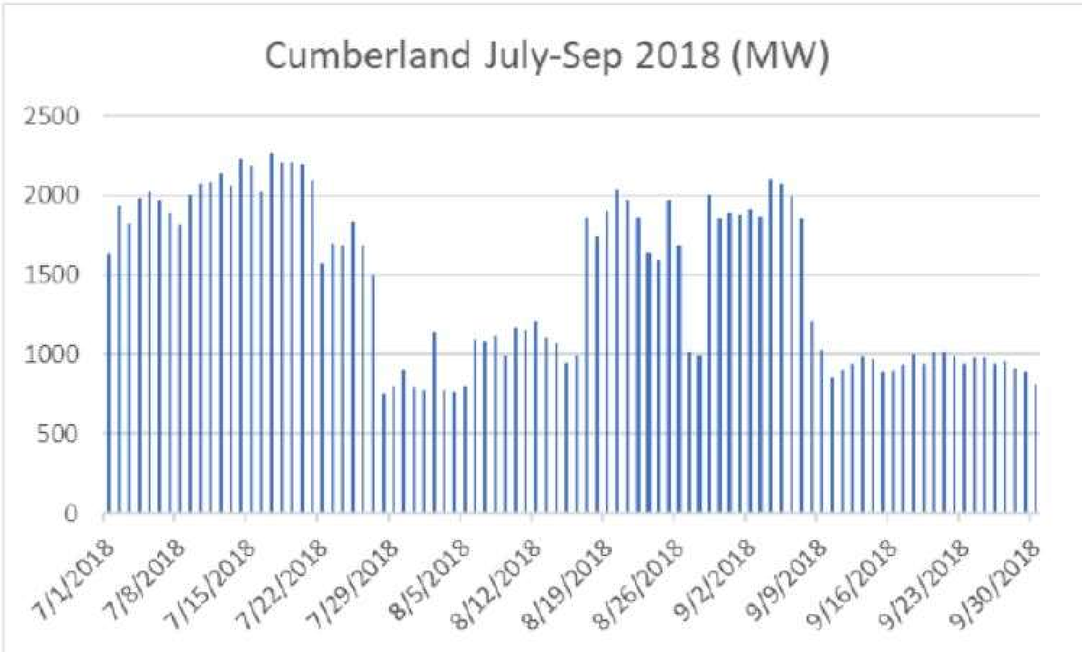
- [Table A-1] 0.19% (or 1900 ppm);
- [Table A-2] 0.23% (or 2300 ppm);
- [Table A-3] 0.23% (or 2300 ppm);
- [Table A-4] 0.21% (or 2100 ppm); and
- [Table A-5] 0.22% (or 2200 ppm).

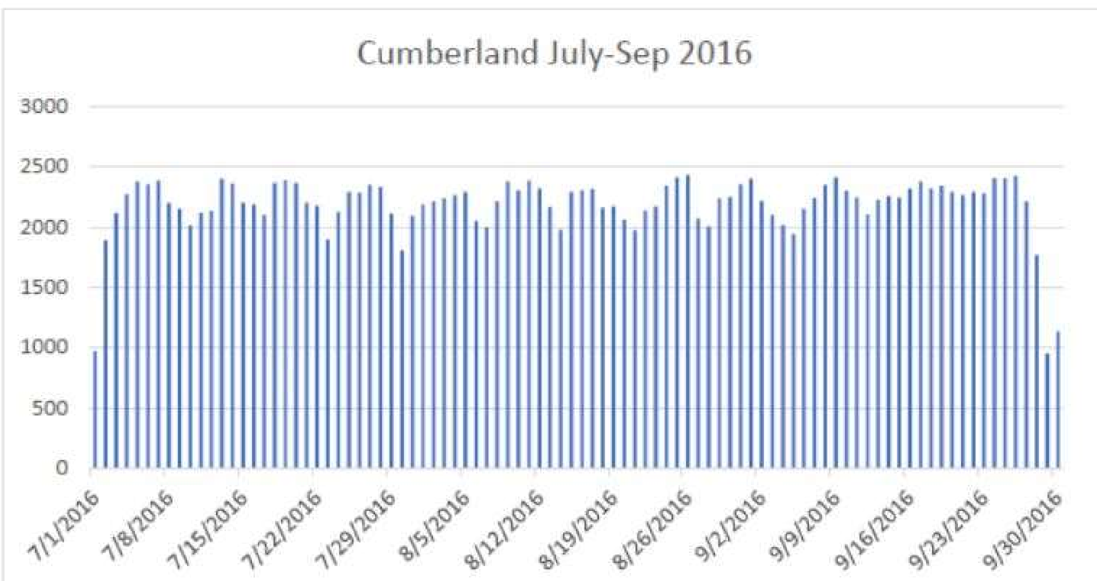
Thus, using its current coals/blends, the coal chlorine content ranges from 1900 ppm to 2300 ppm in the feed. Compare that with chlorine contents of PRB coals, which range from 107-131 ppm.[124] Thus, PRB coals have almost 20 times lower chlorine levels than the coals currently burned at Cumberland, in addition to much lower sulfur contents, as is well known. Thus, blending any amount of PRB coal would have the double benefit of less SO2 to be removed by the FGDs from the flue gases as well as allowing for more recycle of the FGD wastewater since the once-through wastewater would have less chloride content. And, as noted earlier, more recycle means lower FGD purge flow rates – leading directly to lower capital and O&M costs for any treatment technology or combination of technologies. Not consider changes to coal blend before allowing Cumberland to avoid meeting its ELG obligations is a glaring error on the part of EPA.

But it is not the only one. The second major error EPA makes in its cost estimates is not taking into account how the Cumberland units actually run at the present time. The chart below, using data reported by TVA to EPA under the Clean Air Act's Acid Rain program[125] shows the combined daily average MW generation level from 1/1/2010 through the present (i.e., 9/30/2019 – the most recent time period for which this data is available).



The chart above clearly shows that the "baseload" MW provided by the combined units at Cumberland are around 1000 MW or thereabouts recently (i.e., since roughly 2017), having declined from around 1200 MW or so in 2010. In addition, the chart clearly shows that while the units occasionally generate more MW, that too is becoming more and more sporadic, especially in recent years – and those levels do not reach even 2500 MW except very occasionally. Even considering the generally highest generation during the summer months, as is evident from the chart (and the underlying data), consider the two charts below showing the July-September generation profiles in 2018 and 2016 below.





It is clear that there is considerable deterioration in electricity generation even since 2016. And this is readily explainable, given the generally higher levels of gas generation in TVA's system since 2016 as well as the overall decline in the coal-fleet's capacity factors in recent years.

Of course, there is absolutely no evidence in the record that the recent decline in generation (i.e., even the 10 year trend of declining "base load" and the last three years' lower capacity factors, even during peak generation months) will reverse in the future. In other words, these trends are likely to continue and there is virtually no chance that they will be reversed.

Despite these actual changes in Cumberland's operating profile, there is no discussion of it in TVA's or EPA's analysis supporting its subcategorization. To the contrary, EPA's cost estimates, which are based on close to full-load wastewater flow rates of roughly 4,400 gpm (i.e., reflecting Cumberland's roughly 2,500 MW combined maximum generation capacity) assume that the two Cumberland units are generating 2,500 MW day in and day out (which they are not) and assumes that the wastewater treatment system(s) should also be designed to handle these peak flows (which it need not).

In other words, although EPA asserts in the preamble that its rationale for the high flow subcategory "reflects the reasonably predictable flow associated with actual and expected FGD operations,"[126] the agency did not consider the ramifications of Cumberland's actual (and declining) capacity factors in its cost analysis. Had it done so, it would have arrived at the common sense conclusion that one does not (or should not) cost waste water facilities to meet peak demand, which happens relatively infrequently. Instead, EPA should have considered whether: (i) the observed peak demand period at Cumberland could be further reduced via different dispatch strategies considering TVA's system as a whole; and (ii) TVA could add equalization/capacitance (i.e., storage) of FGD wastewater – and whether these two strategies could collectively reduce and decouple peak waste water flow rates from the units from the much lower average flow rates that a waste water system would need to treat by drawing such waters from storage/equalization. .

In the table below, I have used TVA's mass balances provided in Appendix 3 to its 2016 Variance Request in the upper panel. TVA's calculated FGD effluent flow rates in gpm are shown for 3 different solids contents (12%, 15%, and 18%) for each of 5 coal mixes. Four of the five (i.e., A-2 through A-3 in the first column) are "5-lb" coals – i.e., with calculated equivalent SO2 levels in the raw coals of around 5 lb SO2/MMBtu, and the first is actually a "4-lb" coal. In any case, all of the calculations assume maximum generation of 2600 MW (actually somewhat higher than TVA's recent statements that maximum generation at Cumberland is 2,470 MW).

Cumberland - Summary of TVA's Mass Balance Calculations and FGD Flows

[Source: Appendix 3, TVA CUF FDF Request, April 2016]

Table #	Full Load (CUF1+CUF2) MW	Coal Mix	Coal Chrorine (ppm)	Coal S (%)	Coal SO_2 (lb/MMBtu)	SO_2 Emissions (lb/MMBtu)	FGD Effluent (gpm) at Various % Solids			Chloride (ppm) at Various % Solids		
							12	15	18	12	15	18
A-1	2600	20% Uinta-Bowie/80% Sitran Arclair	0.19	2.47	4.06	0.163	4299	3377	2761	1135	1851	2567
A-2	2600	33% Sitran/Arclair	0.23	2.96	4.85	0.194	5107	4011	3279	1517	2264	3011
A-3	2600	Arclair ILB	0.23	2.96	4.74	0.19	5000	3927	3211	1520	2267	3024
A-4	2600	Warrior 5-lb	0.21	3.05	4.87	0.195	5116	4018	3285	1243	1965	2687
A-5	2600	33% Sitran + Warrior 5-lb	0.22	3.02	4.94	0.197	5187	4073	3330	1330	2058	2786

Recalculated FGD Effluent Flows (Scaled from Assumed Full Load of 2600 MW to Actual Average Daily Load of 1244 MW

1244 <------------ Actual Average Daily Load for Last 3 Years

Table #	Actual Load (CUF1+CUF2) MW	Coal Mix	Coal Chrorine (ppm)	Coal S (%)	Coal SO_2 (lb/MMBtu)	SO_2 Emissions (lb/MMBtu)	FGD Effluent (gpm) at Various % Solids		
							12	15	18
A-1	1244	20% Uinta-Bowie/80% Sitran Arclair	0.19	2.47	4.06	0.163	2057	1616	1321
A-2	1244	33% Sitran/Arclair	0.23	2.96	4.85	0.194	2444	1919	1569
A-3	1244	Arclair ILB	0.23	2.96	4.74	0.19	2392	1879	1536
A-4	1244	Warrior 5-lb	0.21	3.05	4.87	0.195	2448	1922	1572
A-5	1244	33% Sitran + Warrior 5-lb	0.22	3.02	4.94	0.197	2482	1949	1593

(yellow) Below 4 mgd (2778 gpm)

Next, in the lower panel, I have scaled the TVA FGD effluent flow rates using an average daily generation of 1,244 MW – which is based on the actual average generation in the last 3 years (i.e., roughly 2017-2019). Not surprisingly, the scaled FGD effluents are lower than what they would be if generation was 2,600 MW. But importantly every one of the flow rates (i.e., for all combinations of coals and solids rates) are below 2,778 gpm – which corresponds to EPA's 4 MGD threshold for the subcategory. In other words, for the vast majority of the time, Cumberland's actual wastewater flow rates (with no changes at all to how the units are operating) are less than 4 MGD - obviating any need for subcategorization at all. To the extent that Cumberland needs to generate power to meet peak demand (and therefore greater than average FGD waste water flow rates) on certain consecutive days, TVA needs to first seriously explore why that demand cannot be met by generation assets elsewhere in TVA's system. Next, TVA should consider blending its current coals with PRB coals to reduce both sulfur and chlorine that needs to be handled by its Cumberland FGDs. That would further reduce FGD wastewater flows, and dramatically so, depending on how much PRB coal is used. Lastly, TVA should consider adding equalization capacity and decouple higher than average FGD wastewater flows from much lower wastewater treatment flows. Together, these would reduce FGD purge flows to much lower than the currently assumed close to 4,400 gpm – which is the basis for EPA's incorrect and over-estimated wastewater treatment costs.

In summary, EPA's incomplete analysis cannot support its conclusion that a high flow subcategory is necessary at all.

120 See id. EPA analyzes a possible set of treatment options "…involving membrane treatment to reduce the FGD wastewater flow rate followed by chemical precipitation and low residence time reduction (LRTR) treatment to treat mercury, arsenic, selenium, and nitrate nitrite…" It arrives at the following costs. Crucially, except for accounting for a small amount of recycle in order to enable chlorides to reach modestly higher levels than TVA's current practice (i.e., still below 3,000 ppm), EPA does not explore additional volume reduction options.

Table 1. Alternative Treatment Order of Magnitude Costs for High Flow Plants (in Millions of 2018 dollars)

Plant Name	Estimated Capital Cost	Estimated O&M Cost	Estimated Annualized Cost
Cumberland	$150-$160	$20-$25	$35-$40

Note: See the Chemical Precipitation Cost Methodology memorandum (DCN SE07093), LRTR Cost Methodology memorandums (DCN SE07094 and SE07120), and Thermal Evaporation Vendor Cost Methodology memorandum (DCN SE07839) for description of the individual cost methodologies.

121 I do not agree, however, that it is the only driver, as EPA has depicted in its cost assessments.
122 See TDD, Section 5.2.1. Every single cost-curve (all are linear) for every FGD wastewater treatment system or combination is based on just purge flow (or "optimized" purge flow) as the only input variable. This is true for capital and O&M costs.
123 This is even more surprising because TVA uses significant quantities of PRB coals in many of its other plants.
124 See Quality Guidelines for Energy Systems Studies, Detailed Coal Specifications, DOE/NETL-401/012111, Exhibit 6-2, at 30 (Jan. 2012).

10 Surface Impoundments

Commenter Name: Jeffrey L. West
Commenter Affiliation: Xcel Energy Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8294-A1
Comment Excerpt Number: 5

Comment Excerpt:

Likewise, it is important that EPA recognizes in this rulemaking that after a generating plant retires, it may be necessary for the associated NPDES permit to continue for some period while the facility undergoes decommissioning and other closure activities. Therefore, it may be necessary for an impoundment that had received CCR contact water such as FGD wastewater and/or Bottom Ash Transport wastewater to continue to operate to manage storm water and other non-coal combustion residuals contact water
waste streams until such time that closure activities have been terminated. Therefore, the final rule should not require that affected impoundments terminate a facility's NPDES permit immediately after the unit ceases to generate electricity.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 99

Comment Excerpt:

4. Surface Impoundments are Not BAT for the Retirement Subcategory

Even if it were appropriate for EPA to establish a subcategory for boilers that will retire by 2028, it must then determine the best available technology for that subcategory by applying the CWA Section 304(b)(1)(b) factors, and based on the best-performing plant for that subcategory as described in Section II - Legal Background. Subcategories are permissible to reflect real operational and physical differences among a source category, not merely to create an exemption from a technology-based standard for a broad swath of the industry.

But EPA has done just that by concluding that surface impoundments are BAT for boilers retiring by 2028.[331] As described in Section III - Southwestern Electric, the Fifth Circuit Court of Appeals decision in the *Southwestern Electric* case makes clear that surface impoundments cannot constitute BAT.[332] The record for this rule establishes that surface impoundments are ineffective at removing dissolved pollutants in the wastewater. EPA has made no findings to the contrary in the proposed rule. EPA instead deems surface impoundments to be BAT without any discussion of what treatment technologies are already in use among the plants in this subcategory, what the best-performing plant is able to achieve, or any of the other standard methods that EPA uses to implement its statutory duty.

EPA's conclusion seems to be that requiring facilities in this subcategory to spend a single dollar reducing toxic water pollution would be too much cost to bear, and therefore EPA will require nothing. Specifically, "EPA proposes to find that surface impoundments are the only technology that would not impose such disproportionate costs on this subcategory of boilers."[333] But EPA has not *even evaluated* what other technologies would cost for units in this subcategory; it has instead summarily determined that any technology, other than the most primitive, imposes disproportionate costs. This does not constitute reasoned decision-making and demonstrates precisely the same flaws of lack of rigor, diligence, and statutory fealty that the Fifth Circuit found with EPA's 2015 determination that surface impoundments were BAT for legacy and leachate wastewater.

EPA asserts that it can skirt its prior finding that surface impoundments are an outdated, inefficient technology by simply citing cost concerns.[334] But the Clean Water Act does not permit EPA to rely upon cost as an overriding concern when establishing BAT.[335] And as demonstrated above, EPA has not shown that the units in this subcategory face unachievable costs.

[331] 84 Fed. Reg. at 64,640.
[332] *Sw. Elec. Power Co. v. EPA*, 920 F.3d at 1003-04, 1007, 1015, 1017-19, 1025-26 (citing 80 Fed. Reg. at 67,840).
[333] Id.
[334] 84 Fed. Reg. at 64,640 ("As mentioned above, the Fifth Circuit's decision in Southwestern Electric Power Company v. EPA left open the possibility that surface impoundments could be used as the basis for BAT effluent limitations, so long as the Agency identifies a statutory factor, such as cost, in its rationale for selecting surface impoundments.").
[335] See Section II - Legal Background; *Sw. Elec. Power Co.*, 920 F.3d at 1007.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 3

Comment Excerpt:

EPA even subjects itself to ridicule by determining that for some poor-performing utilities, an unlined hole in the ground is the best available technology for dealing with a coalfired plant's water pollution.

The country is rejecting EPA's retrograde mentality. Duke Energy, the North Carolina Department of Environmental Quality, and community groups we represent recently announced an agreement that requires the excavation of at least 80 million tons of coal ash from unlined pits across that state.[1] Duke Energy is already required by court orders and settlements to excavate more than 53 million additional tons from 10 coal-fired plant sites across North and South Carolina. All three South Carolina utilities – SCE&G/Dominion, Santee Cooper, and Duke Energy – have excavated or are excavating every unlined waterfront coal ash pit in that state. In fact, five entire sets of coal ash lagoons in the Carolinas have now been completely excavated – at Dan River, Wilmington, Charlotte, Columbia, and Conway. In Virginia, Dominion is required to excavate every pit in that state. Georgia Power has announced plans to excavate almost 50 million tons of ash from pits across the state, and TVA has been required by public pressure and settlement to excavate over 15 million tons from sites in Memphis and Nashville. By our count, utilities in the Southeast are now committed and required to excavate almost a quarter billion tons of coal ash and about 70 percent of all the impoundments covered by the 2015 CCR Rule. And of course, utilities across the region have abandoned primitive unlined pits as the way to dispose of coal ash or to manage streams of wastewater flowing from coal-fired plants. Dry storage and active waste treatment are the standard.

[1] Settlement Agreement, *Duke Energy Carolinas, et. al. v. NC DEQ, et. al.* (Dec. 31, 2019), available at https://www.southernenvironment.org/uploads/words_docs/Final_Agreement_12-31-19_signature_version_-_with_signatures.pdf (Attachment 1).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 7

Comment Excerpt:

And in the face of the fact that utilities across the Carolinas and elsewhere have already stopped putting coal ash in unlined water-filled pits and in fact are well on the way toward removing the ash already in these pits, EPA makes the absolutely incredible assertion that some utilities will not be able to find a place to put their coal ash other than an aging, unlined, leaking, polluting hole in the ground.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 50

Comment Excerpt:

b. Allowing Retiring Plants to Avoid Protective Pollution Limits Until 2028 Is Unreasonable and Unlawful.

Unlined coal ash impoundments do not satisfy the BAT standard. Yet EPA is proposing to allow coal units retiring by 2028 to enjoy weak, non-protective pollution limits by using these unlined impoundments as the model “technology”—an absurd approach, especially since EPA itself has shown that such impoundments do not effectively treat wastewater. This purported exemption from true BAT standards is unlawful because there is no valid justification for allowing utilities to avoid protective pollution limits for another eight years based on the assumption of ineffective, leaking impoundments as BAT.

The Fifth Circuit Court of Appeals has explained the impermissible dangers of unlined surface impoundments:

Far from demonstrating that impoundments are the "best available technology economically achievable" for treating legacy wastewater, the evidence recounted in the final rule shows that impoundments are ***demonstrably ineffective at doing so and demonstrably inferior to other available technologies.*** *In light of this record,* ***we cannot accept that an outdated, ineffective and inferior technology is BAT*** *. . . .* [125]

The Fifth Circuit explained that "everything the rule says about the record of impoundments over the past three decades indicates that their performance in controlling discharges has been distinctly poor."[126] Indeed, the record shows that "impoundments are demonstrably ineffective at doing so and demonstrably inferior to other available technologies."[127]

As the court recognized, "the Supreme Court has explained that a BAT must achieve 'reasonable further progress' towards the Act's goal of eliminating pollution."[128] EPA itself stated in the earlier ELG rule that impoundments "are largely ineffective at controlling discharges of toxic pollutants and nutrients."[129] EPA went on to lay out the critical failings of impoundments in detail:

Pollutants that are present mostly in soluble (dissolved) form, such as selenium, boron, and magnesium, are not effectively and reliably removed by gravity in surface impoundments. For metals present in both soluble and particulate forms (such as mercury), gravity settling in surface impoundments does not effectively remove the dissolved fraction. Furthermore, the environment in some surface impoundments can create chemical conditions (e.g., low pH) that convert particulate forms of metals to soluble forms, which are not removed by the gravity settling process.[130]

[125] *Sw. Elec. Power Co.*, 920 F.3d at 1019.
[126] Id. at 1018.
[127] Id. at 1019.
[128] Id. at 1006 (citing *Nat'l Crushed Stone*, 449 U.S. at 75).
[129] 80 Fed. Reg. 67,840.
[130] Id

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 51

Comment Excerpt:

EPA claims that the Fifth Circuit "left open the possibility that surface impoundments could be used as the basis for BAT effluent limitations so long as the Agency identifies a statutory factor, such as cost, in its rationale for selecting surface impoundments."[131] But the court said no such thing. Instead, the court made clear that the well-documented deficiencies EPA identified with unlined impoundments make them incompatible with the BAT standard.

The Fifth Circuit pointed out that EPA's approach to legacy wastewater, just as with the proposed exception here, is self-contradictory: "having rejected impoundments as BAT because they would not achieve 'reasonable further progress' toward eliminating pollution from those streams, EPA turned around and *chose* impoundments as BAT . . ."[132] The Fifth Circuit held that "[t]hese conceded defects in impoundments are in critical tension with EPA's choosing them as BAT" for legacy wastewater.[133]

The same is true here for plants that will continue to operate until 2028. "The BAT factors are designed to support achievement of an effluent limitation that 'shall require the elimination of discharges of all pollutants,' if 'technologically and economically achievable.'"[134] EPA cannot "simply default[] to the outdated BPT standard [of relying on unlined settling lagoons] that has been demonstrated to be a poor performer by [EPA's] own analysis. ***That is antithetical to the statutorily-mandated BAT standard.***"[135]

As explained above, unlined impoundments are incompatible with the BAT standard because of their well-documented inability to treat FGD and bottom ash wastewater.

[131] 84 Fed. Reg. at 64,639.
[132] *Sw. Elec. Power Co.,* 920 F.3d at 1016 (emphasis in original).
[133] Id. at 1017.
[134] Id. at 1028 (citing 33 U.S.C. §§ 1311(b)(2)(A); 1314(b)(2)).
[135] Id. at 1018 (emphasis added).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 54

Comment Excerpt:

c. The Low-Utilization Exemption Is Unlawful.

EPA is proposing to allow individual coal-burning generating units to avoid complying with the BAT standard for the rest of the industry, and instead use primitive, unlined, leaking impoundments that EPA itself has already documented to be utterly ineffective at treating wastewater.

This proposal would allow numerous facilities in the Southeast to avoid more protective pollution limits and continue using their unlined lagoons for bottom ash. Continued operation of coal ash impoundments risks structural failures or other types of coal ash spills. Impoundments not only fail to adequately treat the wastewater, but they also leak pollutants into the surrounding groundwater and surface water. For example, in North Carolina, Georgia, Virginia, and Tennessee, virtually every unlined coal ash lagoon has reported statistically significant increases of pollutants over groundwater protection standards.[142] For Example, TVA's Gallatin plant is built on karst geology and rapidly-moving pollution leaking out of its impoundments is contaminating the Cumberland River. TVA's Allen facility has caused groundwater contamination of 300 times the arsenic MCL, threatening the Memphis Sand Aquifer, the drinking water source for the city of Memphis.

[142] Groundwater exceedance reporting forms disclosed pursuant to the CCR Rule are compiled at Attachment 49.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 56

Comment Excerpt:

EPA attempts to argue that cost justifies its choice of unlined impoundments as BAT for these facilities. But the agency has made no attempt to demonstrate that selecting impoundments in these circumstances reflects "a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges," which was the intent of Congress in enacting BAT standards in the first place.[148]

[148] *Nat'l Crushed Stone Ass'n*, 449 U.S. at 74; *accord Sw. Elec. Power Co.*, 920 F.3d at 1030.

11 <u>FGD Wastewater – General</u>

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 5

Comment Excerpt:

The proposal includes subcategories of sources that would be subject to less stringent limits (high flow, low utilization and boilers that will retire by 2028) and a voluntary incentive program for facilities that agree to install emerging technology to treat FGD wastewater. However, this voluntary incentive program is not available to indirect dischargers.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC

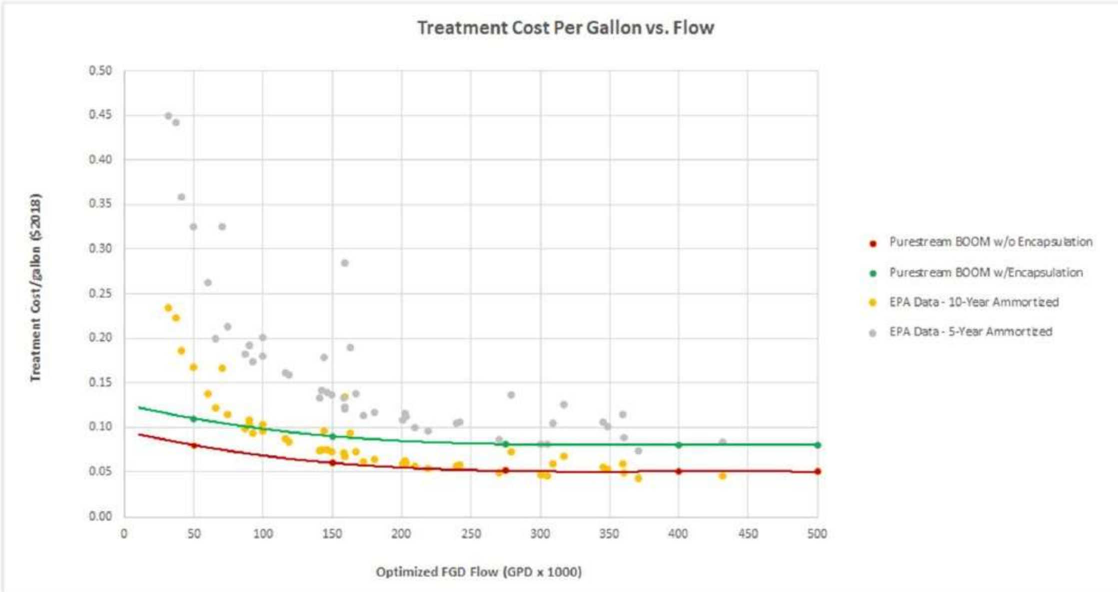
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 11

Comment Excerpt:

In fairness to all technologies and all business offerings, the cost evaluation should more appropriately compare technologies based on their cost per gallon of wastewater treated. For technologies that must be customized for each power plant and purchased by the power plant owner, the EPA should use the traditional approach of estimating capital cost (including engineering and construction management) plus ongoing operation and maintenance costs, spare parts and replacements and determine the costs on a per-gallon of wastewater produced based on 5-year and 10-year capital amortizations. For technologies that are offered as BOOM for a fixed price per gallon treated, the proper comparison is the cost that would be incurred by the power plant per gallon of wastewater that must be treated. Moreover, the comparison must acknowledge that the BOOM approach mitigates the risk of the wastewater treatment investment becoming a stranded asset if the power plant closes prematurely due to power market economics or failure of major equipment unrelated to wastewater treatment. Stranded asset risk should be considered by comparing wastewater treatment alternatives on cost per-gallon treated at 5-year and 10-year amortization periods.

Following is a scatter plot of Table 3. Thermal Evaporation Plant-Level Costs as reported in the EPA's Flue Gas Desulfurization Thermal Evaporation Cost Methodology (DCN SE07098), November 20, 2018. Data points in yellow correspond to 10-year capital amortization; gray corresponds to 5-year capital amortization. Purestream added a red line plot of BOOM cost per gallon, excluding the cost of brine encapsulation and a green line plot of BOOM cost per gallon, including the cost of brine encapsulation.

The plots illustrate that mobile, modular systems with membranes and thermal systems delivered by BOOM business model are less expensive than custom-designed and power site-constructed thermal systems. Moreover, if a power plant is forced to retire, perhaps 5 years early, or it operates for 10 years at a 50% lower capacity factor, then the mobile, modular systems with a BOOM contract are even more economical. When a power plant selects a supplier of mobile, modular technology, wastewater treatment capacity can be increased or decreased to match power plant operational considerations and the BOOM business model protects the power plant owner from radical swings in wastewater treatment cost when the power plant capacity factor or life expectancy change.



The EPA should conduct a similar evaluation to compare the costs of biological treatment (HRTR and LRTR), zero-valent iron, and advanced membrane filtration with mobile, modular systems (combined membranes and thermal) provided by a BOOM contract.

Percentage of power plants where Purestream's BOOM approach is less expensive than custom-designed, site-constructed thermal systems

	% (excluding brine encapsulation cost)	% (including brine encapsulation cost)
Based on 10-year Amortization	73	40
Based on 5-year Amortization*	97	80

*Shortened amortization may be due to early retirement, catastrophic failure, reduced capacity factor etc.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 1

Comment Excerpt:

CWLP, as an indirect discharger subject to the pretreatment standards for existing sources (PSES), is disproportionately impacted by the ELG rule. As CWLP explains in more detail in these comments, CWLP believes it is essentially the only utility that would be impacted by the FGD PSES proposal if adopted and because the Sangamon County Water Reclamation District already meets the effluent limits of the ELG at the end of pipe, CWLP does not believe it is necessary for USEPA to finalize a PSES for existing indirect dischargers of FGD waste at this time. CWLP has consistently maintained that this proposal imposes excessive costs on our facility with no benefit to the environment.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 7

Comment Excerpt:

Even though, the Clean Water Act ("CWA") is clear that USEPA sets separate technology-based effluent limits for indirect dischargers and direct dischargers and that these different technology standards have different goals to be achieved, USEPA has again in the Reconsideration Rule set PSES at exactly the same level as BAT and relied on the same justification.[1] USEPA has provided no justification for why and how the Best Available Technology Economically Achievable is equivalent to the technology needed to prevent pass through and interference at a POTW. CWLP finds it arbitrary, capricious and at odds with common sense to conclude that the proper interpretation of the statute, given the proper level of analysis of the sources and POTWs impacted, could have led to this identical result.

[1] "For indirect dischargers (i.e. discharges to publicly owned treatment works), the proposed rule establishes pretreatment standards for existing sources that are the same as BAT limitations, except for TSS, which there is no pass through of pollutants at POTWs." 84 Fed. Reg. 64,622.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 9

Comment Excerpt:

Specifics on the treatment of CWLP's FGD wastewater discharge at SCWRD

In the case of CWLP, FGD wastewater is pretreated using a chemical precipitation and settling process prior to being discharged through a dedicated force main through the sewer system for treatment at the SCWRD POTW. SCWRD regulates the discharge from CWLP as part of their approved pretreatment program. SCWRD has a well-run pretreatment program and performs regular reassessments of their local limits as required by 40 CFR Part 403. The most recent update to SCWRD's pretreatment ordinance was approved by their Board in the fall of 2019. See Exhibit B for the summaries of the revised ordinance followed by the ordinance language in total. These updates received preliminary approval by USEPA Region V prior to public notice and SCRWD has submitted them for final post-public notice approval which is expected to be imminent.

This reassessment included consideration for the allowable headworks loading in order to protect against violations of the POTW's National Pollutant Discharge Elimination System ("NPDES") permit, protection against violations of water quality standards in the receiving stream, protection of District's infrastructure and staff, prevention of upsets in the wastewater treatment plant, and protection against violations of the District's biosolids permit/compliance with USEPA Part 503 regulations. The pollutants regulated by the PSES ELG were all included as potential pollutants of concern in the SCWRD local limits evaluation and local limits are included in the District pretreatment ordinance for arsenic, mercury and selenium. Both nitrates and total nitrogen were considered in the assessment, but local limits were not determined technically justified based upon the results of the maximum allowable industrial head works calculations. However, both treatment plants owned and operated by the SCWRD are designed for biological nutrient removal providing total nitrogen removal. The local limits adopted by SCWRD and the industrial user pretreatment permitting and monitoring process are in place to insure protection against the pass through effects described in the ELG. In the end, the limits for selenium included in the SCWRD local limits ordinance were not needed to address passthrough or interference related to water quality, but rather to protect the quality of wastewater treatment plant sludge under Part 503. See Exhibit C for 2019 calculations developed for CWLP's local limits and summary of final limits.

The objective of the PSES (both in the plain language and as interpreted by USEPA) is already being satisfied by the local limits that have been developed by SCWRD and USEPA Region V and the other processes in place at SCWRD to protect against pass through or interference at the POTW. Evidence of this absence of pass through and interference is SCWRD's compliance with its NPDES pennit, state-issued biosolids permit, and the biosolids requirements of 40 CFR Part 503. Even if the ELG requirements from the proposal were applied directly to SCWRD's discharge today, they would be met. CWLP is a non-profit municipal utility that shares the same rate-payers as SCWRD, and the current level of treatment with regulation by SCWRD represents the most cost effective means of compliance with existing and future water quality standards. For these reasons, CWLP has maintained that this proposal provides no environmental benefit to the citizens of Springfield and surrounding areas at enormous costs to those citizens that are CWLP's customer-ratepayers.

Commenter Name: Doug Brown
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Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 11

Comment Excerpt:

CWLP has spent a great deal of time trying to identify other similar facilities in order to understand whether the PSES proposal might impact other facilities similarly and how those facilities will deal with compliance with the rigid timelines allowed under the CWA for implementation of a PSES. To date, we have not identified any facilities considered to be similar in terms of the impact of the PSES for FGD wastewater. While working with APPA we were initially able to identify a small handful of other facilities that were impacted by the PSES generally at the time reconsideration was requested. However, that search was not focused on the PSES for FGD wastewater which does not cover those in the handful without an indirect discharge from a WFGD system. There are several statements in the Record that lead CWLP to the conclusion that USEPA is also unable to identify any facilities with similar issues or concerns to CWLP. That is to say, whether there are any other facilities that are an indirect discharger of FGD waste and also have constructed a physical/chemical pretreatment facility to pretreat FGD waste prior to sending it to the POTW.[4]

[4] As explained *infra* p.l, CWLP has already invested $15 million and $1.75 million per year to implement physical/chemical pretreatment for WFGD wastewater meeting the PSES chemical precipitation technology.

Commenter Name: Doug Brown
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Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 12

Comment Excerpt:

In support of the 2015 rule, USEPA relied on the Document "*Methodology for Applying POTW Removals to FGD Pollutant Loadings Calculations*", DCN SE05341, ERG, 9/30/2015. The authors of that document stated that "EPA identified a few plants that reported discharging FGD wastewater to a POTW rather than discharging directly to surface water .... EPA identified one plant that operated a chemical precipitation system at baseline ... " Given that USEPA visited CWLP' s facility and included results of its visit in the 2015 Record, it would seem that no other facility was identified pretreating its waste with chemical precipitation prior to sending it to a POTW in the development of the 2015 rule. See, DCN SE03733, DCN SE03735, and DCN SE03738.[5] Although this information is now several years old, as the PSNS was not reconsidered, any facility becoming a new indirect discharger after November 3, 2015 would be subject to the PSNS rather than the PSES. See, 40 C.F.R. 423.15(b).

USEPA developed information for the Record during the reconsideration period which has confirmed and strengthened this conclusion. In the document "*Flue Gas Desulfurization Membrane Filtration Cost Methodology*" DCN SE07096, (August 23, 2019), the author ERG again developed some information related to indirect dischargers and on page 6 of the document stated "EPA identified two plants from the Steam Electric Survey data that discharge FGD wastewater to a POTW."[6] Those plants are identified in the document as CWLP and the CD

McIntosh Jr. Power Plant operated by the City of Lakeland, Florida. Therefore, it would appear that the Lakeland Plant is the only other Plant known to USEPA to be subject to the FGD PSES and CWLP is aware from communications with that facility that the Lakeland plant has not installed chemical precipitation or biological treatment of its FGD wastestream.

[5] No reference was found in the Record that USEPA requested information on removal efficiencies of the SCWRD plant and nor was evidence found at least in the publically available portions of the record that removal efficiencies for CWLP's pretreatment facility were incorporated Record.
[6] One error noticed in the Record from this document is that ERG used information from the City of Springfield website on residential customer sewer charges (which CWLP has an agreement to bill on behalf of SCWRD to our customers when they overlap) to develop cost information rather than the industrial user rates charged by SCWRD. Unlike the only other discharger EPA has identified with an FGD discharge to a POTW, CWLP does not have any ownership or operational relationship with the POTW other than as a customer.

Commenter Name: Doug Brown
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Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 14

Comment Excerpt:

CWLP found one final piece of information related to the prevalence of facilities subject to the PSES from the proposed rule itself. In footnote 80 on page 64,644, USEPA states with regard to the PSES for BA transport water: "Only two facilities currently discharge BA transport water to POTWs, and EPA believes that both facilities qualify for the proposed subcategorization for low utilization boilers. Thus, this PSES may ultimately not apply to any facilities."

From CWLP's vantage point, it seemed odd that USEPA did not provide a similar footnote explaining the applicability of the PSES for FGD wastewater and how many facilities USEPA expects it to apply to once the new subcategories are considered. It's clear based on the ERG memo that USEPA had only identified two facilities for the FGD PSES. Does this footnote refer to two different facilities? Or does this footnote mistakenly refer to CWLP's facility as being subject to the BA transport PSES and Dallman 4 as a low utilization boiler? CWLP's assumption is that USEPA simply did not include a footnote on the FGD PSES since the older units at CWLP would easily qualify as low utilization boilers, but Unit 4 would not.

This lack of a comparable footnote also highlights another issue specific to CWLP's facility that does not seem to be considered by the Proposed Rule. It does not appear that USEPA considered the scenario present for CWLP of a pretreatment facility that has already been built that treats some low utilization boilers and/or boilers that will retire by 2028 and another boiler that would intend to be in operation past 2028 and is not a low utilization boiler (at the 876,000 MWh threshold as proposed) unless market conditions were to deteriorate. It's likely that there are other direct dischargers in relatively similar or analogous situations. But those facilities will be able to design a new system that is the most cost-effective for meeting all other relevant environmental regulations. Since CWLP does not have the legal or physical ability to by-pass its existing Chemical Precipitation treatment system for some units (and no one would want a rule that incentivized it to do so), CWLP cannot take advantage of the low utilization boiler provisions for the boilers that qualify. CWLP cannot separate wastes from the Unit 31, 32, and 33 from the waste from Unit 4 after the chemical precipitation phase and therefore it cannot build a biological treatment facility for Unit 4 only unless and until Units 31, 32 and 33 have been retired.

This also means there is no ability for CWLP to take advantage of the less stringent requirements for low utilization boilers or boilers ceasing operation by 2028 without curtailing or prematurely retiring Unit 4. Since the cost of developing a biological pretreatment system for Unit 4 only is likely to be less expensive than the $45 - $50 million[7] capital cost estimate Burns & McDonald[8] provided for all 4 Units, there is a clear incentive in this rule as applied to CWLP to either retire all three older units prior to the Summer of 2023 or to prematurely retire Unit 4 by 2028. Premature retirement would leave stranded assets for our local customer rate payers on bonds that will not be completely paid off for this 10 year old Unit until 2040. With regard to the subcategory of boilers retiring by 2028, USEPA solicited "comment on whether this subcategory would adversely incentivize coal-fired boilers planning to retire after 2028 to accelerate their retirement to 2028 .... " 84 Fed. Reg. 64,641. Given the reasons explained in this Section, CWLP feels there is such an unintentional incentive given the unique factors applicable to our facility.

These factors lead CWLP to the conclusion that its facility is the only facility impacted by the reconsidered PSES for FGD wastewater and therefore its site-specific considerations in their entirety are relevant to the reasonableness of USEPA's conclusions in this rule. It begins to look arbitrary and capricious for USEPA not to consider the adequacy of Chemical Precipitation alone in this context and the performance of SCWRD (also a very new and recently upgraded facility) in meeting its NPDES limits (and even the limits contained in the ELG itself) as relevant to the setting of these national pretreatment standards under these circumstances.

[7] To date, CWLP has not studied the cost of a biological pretreatment facility needed for compliance with the ELG rule by Unit 4 only in the very likely event that the three older units are forced to close by 2023 under both the CCR rules and the ELG for dry fly ash handling. In evaluating the compliance time needed for the FGD PSES standard discussed in more detail below, this additional time must be factored in because if the costs of such a system are not lower than the $45 - $50 million capital engineering estimate developed for all four plants, it is likely Unit 4 would no longer be economically viable in the current market conditions.

[8] See, Effluent Limitation Guidelines and Coal Combustion Residuals Final Rules Study, Burns & McDonnell, 4/5/2018. Although this report was provided to USEPA it does not appear in the docket. Therefore, CWLP has attached the Table of Content and Executive Summary as Exhibit D.

Commenter Name: Doug Brown
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Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 16

Comment Excerpt:

As explained above, in addition to BAT and PSES, the 2015 ELG rule also established a more stringent PSNS for any new facility designed to be an indirect discharger or presumably to any existing facility that chose to become an indirect discharger by switching to a POTW from a lake, reservoir, river or stream discharge point. This provision is appropriate and adequate to ensure the rule does not incentivize a facility to try to change its discharge point to avoid treatment.

However, as applied to CWLP (and as the only facility subject to the requirement as applied generally) the proposal seems to incentivize a PSES facility that was able to switch from being an indirect discharger to being a direct discharger. In the event CWLP is required to build the same biological pretreatment facility as any industrial facility will build that discharges directly to Waters of the U.S., this rule seems to incentivize CWLP to become a direct discharger to Sugar Creek.[9] It seems illogical and arbitrary for USEPA to incentivize CWLP against utilizing a regional POTW, but the rule as written would encourage CWLP to find a way to eliminate $1.5 million dollars per year in costs paid to SCWRD as an Industrial User by becoming a direct discharger of FGD wastewater to Sugar Creek instead of to the much larger Sangamon River where it ultimately ends up after treatment by the POTW. Presumably the reason CWLP is even precluded from becoming a zero discharge facility under the Voluntary Incentives Program is because it would be inconsistent with the PSES requirements for CWLP to continue current operation of Chemical Precipitation pretreatment only beyond the three year deadline in the CWA to implement a PSES. It does not appear from the Record that USEPA considered some of these potential negative environmental impacts of the PSES proposal that are distinct from the BAT proposal and unique to CWLP.

[9] On page 6 of the rulemaking record document "Receiving Water Characteristics Analysis and Supporting Documentation for the 2019 Steam Electric Supplemental Assessment," DCN SE07925, ERG October 31, 2019, ERG details the receiving water information assumed for CWLP's discharge. In footnote "a" to the table, it appears the consultant discovered that they had incorrectly linked the discharge point to Lake Springfield rather than Sugar Creek. While this conclusion is accurate for bottom ash transport water for which CWLP is a ***direct*** discharger to Sugar Creek under an NPDES permit, even this correction does not properly identify CWLP's indirect discharge which following treatment at the SCRWD's Spring Creek facility is discharged to the Sangamon River from Outfall 007 (Latitude: 39° 51' 3 7.234" North, Longitude: 89 38' 30.082" West).

Commenter Name: Doug Brown
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Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 20

Comment Excerpt:

Given that no other facilities are expected to be subject to this requirement, it makes sense for USEPA to include a delayed effective date for the FGD PSES in a final rule or to delay finalizing the rule. CWLP actually would argue further that its position in these comments would suggest no PSES is needed at this time and to recommend that USEPA revisit the need for such a limit in 3 years after the adoption of the proposed rule to allow for larger facilities to implement these treatment technologies on a full scale basis before determining whether biological treatment for the one PSES facility with chemical precipitation is needed and achievable.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 22

Comment Excerpt:

In describing its thought process in the proposed rule USEPA states "EPA is continuing to rely on the pass-through analysis as the basis of the limitations and standards in the 2015 rule. With respect to FGD wastewater, as discussed above, the long-term averages for low residence time biological treatment are very similar to or lower than those achieved with high residence time biological systems. On this basis, the EPA proposes to conclude that mercury, arsenic, selenium and nitrate/nitrite pass-through POTWs, as it concluded in the 2015 rule." 84 Fed. Reg. 64,644. USEPA goes on to say: "Thus, like BAT, the EPA proposes to establish PSES based on Option 2: PSES for FGD wastewater based on chemical precipitation plus low hydraulic residence time biological treatment, and PSES for BA transport water based on dry handling or high recycle rate systems. The EPA proposes the technologies as the bases for BAT, and also proposes the same subcategories proposed for BAT." 84 Fed. Reg. 64,644.

In the discussion of the BAT technology decisions relied on in setting the PSES, USEPA states that the primary reason for not selecting Option 1 in the proposal which would be Chemical Precipitation alone is that it does not remove nitrogen, nor does it remove the majority of selenium. 84 Fed. Reg. 64,632. "Because the combination of chemical precipitation with LRTR provides substantial fmiher reductions in the discharge of pollutants, the EPA proposes chemical precipitation followed by LRTR for BAT." 84 Fed. Reg. 64,632.

This analysis has assumed that "well-operated" POTWs utilizing secondary treatment do not remove nitrate/nitrite. This assumption is not accurate for SCWRD, therefore is imposing additional requirements on CWLP where the benefit presumed by the rule is not present. Additionally, while this analysis seems to address the ability of biological treatment to address nitrate/nitrite and selenium, it demonstrates that USEPA did not independently analyze whether these pollutants were causing pass-through or interference at any real world POTWs. As discussed above in some detail, SCWRD has recently updated its local limits and did an extremely thorough and highly conservative analysis of whether pass through or interference is occurring at the POTW. CWLP felt the analysis conducted was in some respects much too conservative and unnecessary to protect water quality and sludge quality. However, it seems that USEPA's analysis has been much less thorough and specific as to the actual real world operation of a POTW treating FGD wastewater. The fact that SCWRD frequently has non-detect values for selenium in its discharge and is more concerned with protecting its sludge quality speaks volumes as to whether there is a pass-through concern on the part of the POTW. See Exhibit A. The new local limits have established a new selenium limit of 0.5 mg/1 to ensure compliance with 40 C.F.R. Part 503 for sludge uses which is already significantly more conservative than the 0.71 mg/1 that was calculated by the USEPA spreadsheets SCWRD used to calculate its limits.

In analyzing removal efficiency for the proposal, USEPA relied on ERG's summary of available information on removal efficiencies. For the four parameters studied, ERG cited removal efficiencies of 98.7% to 99.9% for BAT and compared them to POTW removal values of between 34.3% and 90.2%. Using this information, USEPA concluded, for example, that under its interpretation of pass-through as anything less than BAT that a removal rate of 90% for a POTW of nitrate/nitrite as N compared to the rate of 98.7% for BAT is evidence that nitrogen is "passing through" a POTW. While the Agency has great deference in interpreting its statute, the interpretation that any miniscule percent removal for a POTW less than what has been assumed (not necessarily in this case achieved in full scale practice) by BAT is 'passing through' seems inconsistent with the plain language of the CWA.

For N and selenium, the analysis in Table 8-5 in determining 'pass through' compares literature values ERG determined to be representative of POTW treatment alone to BAT treatment of full chemical plus biological. "*Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*," USEPA, EPA-821-R-19-009 (November 2019) p. 8- 8. There is no consideration given to whether the pass-through answer is different for a POTW's removal efficiency at treating FGD wastewater that has already undergone physical/chemical treatment. While USEPA did consider the relative impacts of biological and chemical treatment in setting the BAT (arsenic and Hg are based on chemical treatment alone), because of the additional pass-through analysis needed, the determination that biological treatment is needed on top of chemical treatment to prevent pass-through at a POTW cannot be made by simply transferring the BAT assumption. It was an abuse of discretion to conduct the pass-through and interference analysis in this manner.

CWLP does not have information on the removal efficiency of its chemical treatment process for selenium and the information it does have on SCWRD's process is difficult to interpret because so many effluent data points are non-detect. It is hard to disagree with the conclusion that the removal percentage of the two combined is likely less than the 99.8% utilized for BAT, if accurate. But CWLP believes that USEPA should seriously consider whether the analysis it has conducted is an appropriate procedure for conducting a pass-through analysis under the statute and regulations and whether further information is needed to support a PSES for FGD wastewater to conclude that it must adopt BAT. If USEPA studied this information when it visited CWLP's facility that is not clear from the publically available documents in the Record.

Discharging to a POTW with a well-permitted and run pretreatment program with regular updates to local limits ensures that the pollutants of concern within the FGD waste are prevented from passing through to the receiving stream. Although the ELG rational for Proposed PSES states that mercury, arsenic, selenium, and nitrates pass through POTWs other available information including USEPA publications suggests otherwise. In fact, local data indicates very high removal of mercury at the POTW. It would appear that USEPA has underestimated the level of treatment provided by the combined industrial pretreatment followed by additional treatment at the POTW which would skew the benefit analysis of the rule.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 23

Comment Excerpt:

Removal Efficiency Assumptions for POTWs

As discussed above, USEPA appears to be basing their conclusion on the performance of generic biological treatment systems rather than collecting data from actual POTWs. USEPA's own publications indicate that the agency has reviewed the removal efficiency in POTWs for mercury, arsenic, selenium in the past and do not support the conclusion that these pollutants simply pass through. USEPA's "*Fate of Priority Pollutants in Publicly Owned Wastewater Treatment Works*" (EPA 440/1-82/203) included an assessment of data and removal efficiencies through secondary treatment for Arsenic, Selenium, and Mercury. This information was also republished in USEPA's "*Local Limits Development Guidance*" (EPA833-R-04-022A). These publications report a median removal efficiency for arsenic, mercury, and selenium of 45%, 60%, and 50% respectively. Tables in these publications also indicate that there is a wide range of variation in the data collected and that some sites reported much higher removal efficiencies.

The removal of nitrates through POTWs varies with location, but many plants are now providing removal of nitrates as facilities are upgraded for biological nutrient removal. In addition, nitrates can be consumed within the wastewater collection system prior to ever reaching the wastewater. In fact, design manuals such as "*Design of Water Resource Recovery Facilities - WEF Manual of Practice No. 8 ASCE Manuals and Reports on Engineering Practice No. 76 6th edition*" provide information on the typical influent of municipal wastewater treatment plants and report that influent nitrates are uncommon. Denitrifying bacteria within the sewers can utilize the nitrate as an oxygen source to meet biochemical oxygen demand preventing sulfate reduction from occurring. For this reason, nitrates are commonly used by clean water utilities as a chemical additive into the sewer system to combat odor and corrosion problems. The mechanisms of sulfate reduction and its prevention using nitrates is discussed in detail in USEPA's "*Design Manual Odor and Corrosion Control in Sanitary Sewer Systems and Treatment Plants*" (EP A/625/1- 85/018). Considering the corrosion prevention benefits, the presence of the nitrates in FGD waste maybe beneficial in some cases to help offset the effects of sulfides also present in the FGD waste stream.

In the case of Springfield, SCWRD evaluates removal efficiency through the POTW as part of their local limit reassessments. The calculations from the last local limit assessment indicates a recorded removal efficiency of 90% for mercury at the POTW. Plant specific removal efficiencies could not be determined at the POTW for Arsenic and Selenium due to data below detection limits. Therefore, SCWRD utilized aforementioned data published by USEPA for the development of maximum allowable headworks loadings for Arsenic and Selenium.

It would seem that POTW specific data would be readily available as information already collected by these utilities. In fact, in Illinois there is a standard Special Condition included in NPDES permits for POTW Pretreatment Programs even though Illinois does not have approval to administer a Pretreatment program under the CWA. Monitoring requirements within this special condition require sampling of the influent, effluent, and sludge for items such as metals, national pollutants of concern, and organic priority pollutants. All of this information is required to be submitted to USEPA Region V on an annual basis; therefore, USEPA already has access to this statewide data set from which they could examine actual removal efficiencies at POTWs. The Agency should conduct a more detailed analysis of the removal efficiency at POTWs given the existence of readily available data and published information contradicting USEPA's current conclusions.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 24

Comment Excerpt:

As CWLP has stated previously in comments to USEPA, it is expected that current compliance costs for the PSES consisting of chemical plus biological treatment was estimated by Burns & McDonald numbers to range between $45 and $50 million for current operation of 4 units. This number will have to be reevaluated based on the new numbers increasing for selenium and nitrate/nitrite and decreasing for mercury and arsenic. It is also likely that these costs of compliance cannot be justified for our older units (even without further study) and therefore the numbers would have to be revisited for a system designed only to treat Unit 4. But even without knowing any of these costs, it is very clear to CWLP that USEPA did not assume costs like those obtained from our engineering study for this rulemaking.

Commenter Name: Doug Brown
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Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 34

Comment Excerpt:

USEPA should decline to adopt a PSES for FDG wastewater at this time because a PSES is not necessary to achieve environmental benefit as applied to CWLP and its POTW SCWRD due to the use of physical/ chemical treatment at CWLP and nitrification at SCWRD. Because it appears that the PSES for FGD wastewater will apply to no other sources other than CWLP

USEPA should decline to adopt a PSES at this time as unneeded and not supported by the Record.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 15

Comment Excerpt:

2.2 **EPA appears to have underestimated the peak FGD wastewater design flow used to size equipment by assuming many facilities can reduce flow to average flows to reduce wastewater treatment costs. But, many facilities will have FGD operational limits, in addition to chlorides, that will prohibit reducing flow rate.**

In the 2013 proposed ELG rule, EPA stated that they estimated flows for some FGD wastewater treatment systems based on the typical or average flow reported by the power plant, then multiplied that average flow rate by a "mean capacity factor" of 1.99. This is a standard industry approach, as treatment systems must be able to treat to compliance levels at all operating conditions. However, in the 2019 cost estimate calculations, it appears that EPA does not multiply by a mean capacity factor [ERG, 2019b], instead asserting that plants can reduce flow so designing for current average flow can provide adequate conservatism.

In practice, wet FGD systems typically manage their recycle based on their chloride/halogen concentrations, to protect the materials of construction, as well as their concentration of fines or other operational considerations; thus flows can vary. Higher concentrations of fines could potentially disrupt gypsum dewatering, gypsum quality, and oxidation-reduction potential (ORP) stability in some wet FGD systems; flow could thus increase over reported averages. In addition, longer residence times in the FGD absorbers due to reduction in FGD purges would lead to concentrating trace metal levels, which could potentially increase mercury flue gas re-emissions in some wet FGD systems. EPA's approach of assuming that facilities can reduce flow rates is a very broad and inaccurate assumption which leads to underestimating the size and cost of treatment systems.

EPRI reviewed the flows reported by EPA and used best professional judgement to resolve flow changes from the 2009 ICR response. Then EPRI estimated a peak flow for each plant in one of four ways:

- If EPA's 2019 FGD purge flow matched the plant's reported typical purge flow (ICR response B5-2) or if it appeared that EPA made reasonable adjustments to the plant's reported typical purge flow based on units added/retired since the ICR response, then EPRI used EPA's assumed FGD purge flow. To determine peak flow, EPRI multiplied EPA's FGD purge flow by a peaking factor of 1.5.

- For two plants, there was insufficient information to understand why EPA had reduced the plant's reported purge flow since the ICR response. For these plants EPRI used the plant's original ICR response for FGD purge flow (ICR response B5-2) and then applied a peaking factor of 1.5 to determine the plant's peak flow.
- EPRI used the plant's reported peak wastewater treatment system (WWTS) design flow (ICR response D5-3), where it was more suitable in EPRI's best professional judgment. No peaking factor was applied where EPRI used the plant's reported peak WWTS design flow.
- For two plants, EPRI used a peak flow basis derived from the original FGD WWTS design flow (ICR response D5-3), which was adjusted based on units added/retired since the ICR response.

For the total industry-wide flow of FGD wastewater needing treatment, EPRI used 53 million gallons per day (MGD) while EPA used 35 MGD. This difference in flow rates is a major element in the cost differences between EPA and EPRI.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 19

Comment Excerpt:

1. EPA's flow rates are biased low by its new method.

EPA appears to have underestimated the peak design flow rate used to size equipment by assuming many plants can reduce flow to reduce wastewater treatment costs. Instead of using the approach it used in the 2013 proposed ELG rule, which was based on applying a mean capacity factor of 1.99 to reported average flow rates, EPA uses the average flow for purposes of designing the new systems.[27] While facilities will attempt to implement efficient water management practices and recycle blowdown to the scrubber to reduce makeup water needs, there will be a practical limitation to the degree of recycling as well as a design limitation related to what a vendor will guarantee.

A comparison of EPA flow rates and plants in the Southern Company system's flow rates used to size equipment is provided in Table 2. Plants in the Southern Company system's design flow rates are approximately two times EPA's estimated flow rates. The Southern Company system's plants will have FGD operational limits that will prohibit reducing flow rate to the levels EPA has assumed. Plants in the Southern Company system's scrubber design will not support a high recycle operation due to (1) limitations on cycling up based on biological treatment supplier influent restrictions (<15,000 ppm chloride); (2) limitations on the ability to reduce treatment sizing by recycling additional blowdown water back to the FGD due to scaling concerns; and (3) lack of recycle infrastructure installed (i.e., the investment needed to achieve a smaller flow rate offsets savings of a small treatment system). EPA's belief that many plants can reduce flow rates is a very broad assumption that will not be true for many in the industry and has caused the agency to substantially underestimate the size and cost of FGD wastewater treatment systems.

Table 2: Comparison of EPA's Design Flow Rates to Plants in the Southern Company System's Design Flow Rates

Plant Name	EPA		Southern Company System Plants	
	Design Flow Rate (gpm)	Optimized Flow Rate (gpm)	Design Flow Rate (gpm)	Average Flow Rate (gpm)
Gaston 5	236	49	600	300
Miller 1-4	313	6	600	300
Bowen 1-4	666	250	1,425	1,425
Wansley 1-2	451	113	600	600
Barry 5	153	6	300	200
Scherer 2-4[28]	18	12	15	100

[28] Plant Scherer Unit 1 was omitted from EPA's analysis, though it should have been included.

27 Id. at 2-2 to 2-3.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 2

Comment Excerpt:

The revised mercury limits may require many sites to redesign treatment systems and install additional equipment if they have already begun design and installation using the less stringent mercury limits that were in 2015 ELGs. TVA is providing additional information on anticipated costs to aid in an accurate evaluation of the treatment sytstems which will be required to meet the proposed limitations.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 10

Comment Excerpt:

Part 423.11 (x) defines high FGD flow as "the maximum daily volume that could be discharged is above 4 million gallons per day after **accounting for that facility's ability to recycle the**

wastewater to the maximum limits for the FGD system materials of construction [emphasis added]." There are several concerns with this definition.

TVA believes that the requirement to recycle FGD wastewater back to the absorber solely based on materials of construction (Pages 64622, 64638, and 64672) is too restrictive. Chloride concentrations are used as the basis for materials of construction; however, WFGD blowdown may also be required based on other operating parameters such as total suspended solids or aluminum-fluoride binding of the limestone that can periodically occur. Instead, TVA recommends that EPA indicate that exemption be based on the "volume achieved after reducing the process flow to the extent practicable based on the limits of system design" or similar language. This more general language reflects recycling or other flow reductions where practicable (i.e., flow is optimized) consistent with the statement EPA makes on Page 64631 (footnote #16) that "facilities would take steps to optimize wastewater flows as part of their operating practices (by reducing the FGD purge rate or recycling a portion of their FGD wastewater back to the FGD system) ... ".

Operational data from TVA's Cumberland Plant are limited but show that chlorides can be close to the 3,000 parts per million (ppm) materials of construction limit. Chloride levels ranged from approximately 1,600 ppm to 2,600 ppm. 2600 ppm chlorides is approximately 87% of the 3000 ppm nominal value. Incurring costs for a project to install piping, controls, etc., to recycle FGD water is not warranted as that equipment may or may not be utilized due to increased operational and marketing risks. TVA believes the wastewater treatment flow has already been optimized. TVA has undertaken a project to reduce FGD flows by up to 700 gallons per minute in modifying how the scrubber effluent tank pumps operate eliminating the addition of that raw water for level control and pump activation.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 25

Comment Excerpt:

2.3 FGD Purge Volume Reduction and Lower Treatment System Costs

FGD purge volume is a key factor in determining the costs of complying with any effluent standard. Although it may be obvious, reducing the FGD purge volume to the maximum extent possible is always a good idea regardless of the next step – whether it is achieving ZLD or subjecting it to other treatment in order to meet concentration limits. Yet EPA's analysis appears to take existing purge volume as a given.

While somewhat simplistic, EPA's cost analysis, per Section 5 of the TDD supporting this rule, is entirely based on maximum FGD purge flow rates.[57] Both capital and operating and maintenance (O&M) costs are assumed to vary linearly with purge flow rate. Thus, reducing purge flow rates to the minimum possible value will result in the lowest-cost treatment/ZLD systems.

In view of this, I am surprised that EPA did not elaborate on various potential means that companies should consider in achieving lower purge flow rates except for what it called optimized purge flows[58] – in which enough recycle of the FGD wastewater was assumed to raise the chloride content of the stream closer to the material capability of the FGD absorber vessel.

It is my opinion that additional options that EPA should have considered include:

(i) Revisiting the coal type used in a boiler. As EPA's own analysis shows, purge flow rates are dramatically different for different coal types – especially bituminous and sub-bituminous. EPA has estimated these median flow rates to be 0.1454 and 0.0392 gallons per day (GPD) per tons of coal burned per year, for bituminous and sub-bituminous coal, respectively.[59] As this shows, FGD purge volumes for the lower sulfur and lower chlorine Western U.S. sub-bituminous coals is much smaller than Eastern bituminous coals. Thus, encouraging coal substitution or blending of bituminous coals with sub-bituminous coals will result in lower purge rates and therefore lower costs of treatment or achieving zero discharge regardless of the technology used.

(ii) Differentiating between base and peak loads and their respective purge flow rates. It is my opinion that since most coal units do not operate as base load units with constant unit operations and therefore constant (and maximum) purge flow rates, any waste water treatment system should be designed so that there is sufficient equalization capacity to provide the capacitance to handle peak flows for short durations. This would allow for wastewater treatment systems to be designed based on lower, average flows reflective of longer-term average performance of the plant and its units. Again, this will result in lower costs for the wastewater system. As noted above, EPA explicitly chose to base its costs on the "maximum possible FGD purge flow"[60] thereby significantly inflating the costs of treatment.

EPA's cost analysis, as provided in the TDD, Section 5, bases its purge rates on 2016 coal usage.[61] However, EPA does not state why it picked 2016 as the year for estimating purge rates. Since EPA assumes that the purge rate, as noted above, is simply a function of the coal usage, it is important to note that coal usage in years 2017 and 2018 is less than it was in 2016, reflecting the decline in coal use for electricity generation for some time now in the US.[62] Had EPA used more recent coal use data, it is my opinion that estimated purge rates would have been even lower, and the corresponding estimated capital and O&M costs would also have been lower. I urge EPA to revisit this issue and the impact it has on the cost estimates provided in the proposed rule.

57 See TDD at 5-6. "The EPA used the FGD purge flow rates to calculate capital costs, which <u>may overestimate the size and cost of the treatment system that plants would actually install</u>; however, the EPA chose to use this flow rate for capital costs to ensure that installed treatment technologies would be able to accommodate the maximum possible FGD purge flow." (emphasis added).
58 See TDD at 5-6. "…the EPA identified individual plants as having the potential to optimize FGD purge flow if the operating chloride concentration is lower than 80 percent of the maximum design concentration. If the operating chloride concentration is not lower than 80 percent of the maximum design concentration, the EPA assumed that further flow optimization was not practical and the resulting optimized FGD flow rate is equal to the FGD purge flow."

I note, however, that in its optimization, EPA did not consider the maximum extent to which optimization (i.e., purge volume reduction) could occur. As EPA stated:
"The EPA limited the degree of flow optimization for each plant so that the resulting operating chloride level would not exceed 30,000 ppm or 80 percent of the plant-specific design maximum chloride level, whichever is lower."19 TDD at 5-7. "Data in the record shows that biological treatment systems operate without impairment at chloride concentrations well above 30,000 ppm and TDS concentrations well over 100,000 ppm. Nevertheless, recognizing that power companies have expressed preference to operate such systems at moderate chloride levels, EPA's cost analyses are based on operating the FGD system so that chloride concentrations in the FGD purge do not routinely exceed 30,000 ppm." Id. at 5-7 n.19.
59 TDD at 5-5.
60 Id. at 5-6.
61 Id. at 5-5, Equation 5-1
62 I have reviewed data submitted by power plants to EPA under the Acid Rain program, available at www.epa.gov/ampd. Over 65% of the units for which EPA has estimated costs (see, for example, in ERG Memorandum Re: Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090 (Sept. 25, 2019) (EPA-HQ-OW-2009-0819-8220) Table 3 had lower capacity factors in 2017 or 2018 as compared to 2016.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 24

Comment Excerpt:

3.4 **Water quality monitors for real-time measurement of selenium and mercury are not proven in FGD wastewater**

A water quality monitor that can provide prompt warning of exceedances of the ELG limits is essential for process control of physical-chemical and biological treatment of FGD wastewater. Sending samples to a commercial or in-house laboratory can result in a wait of days to weeks until results are known. EPRI has performed extensive laboratory and field tests of online water quality monitors for selenium and mercury in FGD wastewater, as well as benchtop units that could be used at the location of a utility wastewater treatment plant. To date, the commercially available and prototype monitors that EPRI has tested in the field have not exhibited the required sensitivity, accuracy, and ruggedness for use in this application [EPRI, 2019]. The selenium monitors require extensive optimization to tailor automated sample digestion methods to a specific FGD wastewater, and often exhibit low biases due to incomplete conversion of recalcitrant selenium species. One prototype mercury monitor that was tested in the laboratory showed promise for measuring biologically treated FGD wastewater accurately at a site-specific limit of 12 ng/L, but the ability to measure accurately at the proposed VIP long-term average of 5.1 ng/L has not been determined. EPRI plans to conduct further field testing of mercury and selenium monitors with the goal of identifying a solution for FGD wastewater treatment monitoring that can be integrated into the process control system.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 48

Comment Excerpt:

6.3 **Cost effectiveness of FGD wastewater technology options**

EPRI's estimate of cost-to-pollutant reduction ratios for the FGD technology options considered by EPA are shown in Table 6-3. EPRI's analysis shows that the cost of chemical precipitation plus biological treatment per toxic-weighted pounds equivalent (TWPE) is an order-of-magnitude lower than the cost-to-pollutant reduction ratio for the voluntary incentive program (VIP) option. Treatment pollutant reductions are better understood with respect to the relative toxicity of parameters. Therefore, EPRI believes TWPE, a relative measure of the potential toxicity of different pollutants, the more appropriate basis with which to calculate treatment cost-effectiveness. Thus chemical precipitation + biological would be more cost-effective than the Voluntary Incentive Program, with a cost-effectiveness ratio of 484 as compared to membrane filtration technology.

Table 6-3
Cost effectiveness comparison of technology options for a 300 gpm case study plant ($2018) [e]

Chemical Precipitation [a]		Chemical Precipitation + Biological [b]		Voluntary Incentive Program [c]	
Cost/TWPE [d]	Cost/pound	Cost/TWPE [d]	Cost/pound	Cost/TWPE [d]	Cost/pound
361	19	484	5.1	1,878	2

TWPE = toxic-weighted pounds-equivalent
$ = U.S. dollars, pre-tax in 2018 dollars
[a] Chemical precipitation system with 2x60% redundancy. See Table 2-2 for cost estimate.
[b] Chemical precipitation system with 2x60% redundancy and Biological LRTR system with nitrate pre-treatment. See Table 2-2 and Table 4-4 for cost estimate.
[c] Chemical softening system with 2x60% redundancy, N+1 ultrafiltration and RO system, and brine solidification. See Table 4-4 for cost estimate.
[d] See Table G-4 for effluent water quality assumptions.
[e] Table values are based on EPRI's cost and pollutant removal estimates.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 25

Comment Excerpt:

In addition, the docket in the record with the Document Number SE07699.Att1 provides the toxic-weighted pound equivalents (TWPE) values USEPA relied on in evaluating costs and environmental benefits for the various options considered in the Reconsideration Rule. For Option 2, which is the proposed rule USEPA found the cost to be $3,245 per /TWPE (in 1981 dollars) for indirect dischargers. This value is over 8 times the value USEPA previously relied on to compare all TWPE values to $404/TWPE (in 1981 dollars) to find anything over that amount was excessive. Even though USEPA is not relying on this analysis in development of the PSES or BAT it seems quite arbitrary and unreasonable to conclude that PSES must be the exact same as BAT when the same technology for BAT resulted in a TWPE of 19 times greater than the TWPE value obtained for direct dischargers.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 69

Comment Excerpt:

G —APPENDIX: FGD WASTEWATER POLLUTANT REDUCTION METHODOLOGY

G.1 Flue gas desulfurization wastewater treatment pollutant reduction

In this Appendix, pollutant reductions are expressed in toxic-weighted pounds-equivalent (TWPE) and pounds. The overall cost-effectiveness of pollutant reduction reflects the cost per TWPE or pounds removed.

G.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the pollutant reductions of flue gas desulfurization (FGD) wastewater treatment to the steam electric industry based on EPA's industry profile [ERG, 2019a]. This appendix includes the methodology and calculation of the estimated pollutant reductions for the treatment technologies evaluated by EPA: chemical precipitation, biological treatment, and chemical precipitation plus voluntary incentive program. Table G-1 outlines the pollutant reduction of FGD wastewater treatment to the industry.

Table G-1
FGD wastewater treatment pollutant reductions to the industry

Treatment Type	TWPE per Year Removed	Pounds per Year Removed
Chemical Precipitation	227,000	82,200,000
Incremental Biological	50,100	32,500,000
Chemical Precipitation + Biological	277,000	115,000,000
Incremental Voluntary Incentive Program Option	391,000	912,000,000
Chemical Precipitation + Voluntary Incentive Program Option	618,000	994,000,000

TWPE = toxic-weighted pounds-equivalent

EPRI estimated the pollutant reductions of three FGD wastewater treatment technologies. The treatment technologies evaluated were (1) CP, (2) biological, and (3) CP + Voluntary Incentive Program option (VIP).

G.1.2 Calculation methodology

G.1.2.1 Pollutant reduction calculation overview

For this analysis, the pollutant reductions of treatment were defined as the amount of pollutants removed from wastewater. The pollutant reductions were calculated as toxic-weighted pound equivalents (TWPE) and pounds. Toxic weighting factors (TWF) are used by the EPA to express the relative toxicity of parameters. Use of TWPE provides a relative measure comparing the potential toxicity of different pollutants. EPRI used the concentration of pollutants in the water, wastewater flow, and the TWFs published by EPA to calculate TWPE. The TWFs used in this evaluation were published in *Technical Support Document for the Annual Review of Existing Effluent Guidelines and Identification of Potential New Point Source Categories* [EPA, 2009] with updated factors for arsenic, cadmium, copper, manganese, mercury, thallium, and vanadium as published in *Review of Toxic Weighting Factors in Support of the final Steam Electric Effluent Limitations Guidelines and Standards* [ERG, 2015]. Pounds were calculated by taking the sum of analyte data excluding total suspended solids, total dissolved solids, biological oxygen demand, and chemical oxygen demand.

G.1.2.2 Defined terms

Terms used in this evaluation are defined below

- Untreated FGD wastewater – The FGD purge stream after primary solids separation (e.g., hydrocyclone overflow) that is transferred to the FGD chemical precipitation wastewater treatment system, prior to any commingling with other wastewaters or treatment system recycle streams. This data is used to calculate the settled FGD wastewater as described below.
- Settled FGD wastewater – To estimate the pollutant concentrations from a typical settling pond effluent, EPRI used the EPA assumption that the concentration would be equal to the sum of a portion of the concentration of the solids and the dissolved pollutants present in the untreated FGD wastewater. These calculations are described in the Summary of Available Data section below.
- Chemical precipitation removal –The amount removed (TWPE and pounds) through treatment by chemical precipitation.
- Incremental biological removal – The incremental amount removed (TWPE and pounds) across the biological treatment system only. The biological treatment influent is assumed to be the chemical precipitation effluent.
- Chemical precipitation + biological removal – The total amount removed (TWPE and pounds) across the CP and biological treatment system. This is calculated as the addition of CP removal and incremental biological removal.
- CP + VIP removal – The amount removed (TWPE and pounds) across CP + VIP.

- Incremental VIP removal – The incremental amount removed (TWPE and pounds) across the VIP. This is calculated as the pollutant reductions of CP + VIP minus the pollutant reductions of CP.
- Coal Type. In EPRI's evaluation of coal type, plants were categorized as Bituminous Coal if only bituminous coal was burned. Plants considered sub-bituminous if only sub-bituminous coal was burned. All other plants were considered to be "Blend/Other," this included coals firing lignite or petroleum coke, blends of coal, or plants that redacted their coal type in the ICR.

G.1.2.3 Summary of data used for the pollutant reduction evaluation

The pollutant reduction calculation uses data that EPA collected as part of its efforts to develop ELGs for the steam electric industry.

EPA sampled FGD wastewater at the following seven facilities with existing FGD wastewater treatment systems in 2010:

- Mirant Mid-Atlantic LLC's Dickerson Generating Station
- Allegheny Energy's Hatfield's Ferry Power Station
- RRI Energy's Keystone Generating Station
- We Energies' Pleasant Prairie Power Plant
- Duke Energy's Belews Creek Steam Station
- Duke Energy's Allen Steam Station
- Duke Energy's Miami Fort Station

Each facility uses chemical precipitation, as shown in Table G-2. Three facilities also have biological treatment plants that follow the chemical precipitation treatment. Of these three, only two (Allen and Belews Creek) have biological systems designed for selenium removal. The third biological treatment plant (Dickerson) is designed for removal of nitrogen.

Table G-2
Summary of treatment systems by plant from EPA's 2010 sampling studies

	Chemical Precipitation					Biological Treatment	
	Equalization	Desaturation	Metals Removal (Organo- sulfide addition)	Clarification	Filtration	SBR	ABMet®
Dickerson	X	X		X		X	
Hatfield's Ferry Power Station	X	X	X	X	X		
Keystone Generating Station	X	X	X	X	X[a]		
Pleasant Prairie Power Plant	X	X	X	X			
Belews Creek Steam Station	X	X	X	X	X		X
Allen Steam Station	X	X	X	X	X		X
Miami Fort Station	Confidential						

[a] Filtration includes sand filtration followed by polishing filters containing Teflon® media ABMet® = Advanced Biological Metals Removal Process (for selenium)
SBR = sequencing batch reactor (for nitrogen removal)

During 2010, EPA and their contractor Eastern Research Group, Inc. (ERG) collected samples over a four-day period at each of the seven facilities. The samples were analyzed for the following:

- Biochemical oxygen demand, 5-day (BOD5)
- Chemical oxygen demand (COD)
- Total suspended solids (TSS)
- Total dissolved solids (TDS)
- Sulfate
- Chloride
- Total Kjeldahl nitrogen (TKN)
- Ammonia as nitrogen
- Nitrate/nitrite as nitrogen
- Total phosphorus
- Total cyanide
- Total metals:
    - Aluminum, antimony, arsenic, barium, beryllium, boron, cadmium, calcium, chromium, cobalt, copper, iron, lead, magnesium, manganese, mercury, molybdenum, nickel, selenium, silver, sodium, thallium, tin, titanium, vanadium, and zinc.
- Dissolved metals:
    - Same parameters as listed for total metals, plus hexavalent chromium

EPA also instructed each of the seven facilities to collect samples one day per month for four months for the same analytes except for the dissolved metals analyses. Untreated FGD wastewater and chemical precipitation effluent were collected at the seven plants. Biological system effluent (SP-3) was collected from the three plants with biological treatment systems.

The data from the four-day sampling conducted by EPA and ERG used in EPRI's evaluation can be found in the following reports by ERG:

- *Sampling Episode Report Mirant Mid-Atlantic, LLC's Dickerson Generating Station Sampling Episode 6562* (December 2011)
- *Sampling Episode Report Allegheny Energy's Hatfield's Ferry Power Station; Masontown, PA, Sampling Episode 6564* (December 2011)
- *Sampling Episode Report RRI Energy's Keystone Generating Station; Shelocta, PA, Sampling Episode 6563* (December 2011)
- *Sampling Episode Report We Energies' Pleasant Prairie Power Plant; Pleasant Prairie, WI, Sampling Episode 6569* (December 2011)
- *Sampling Episode Report Duke Energy Carolinas' Belews Creek Steam Station; Belews Creek, NC, Sampling Episode 6558* (December 2011)
- *Sampling Episode Report Duke Energy Carolinas' Allen Steam Station; Belmont, NC, Sampling Episode 6561* (December 2011)
- *Sampling Episode Report Duke Energy Miami Fort Station; North Bend, OH, Sampling Episode 6560* (December 2011)

Data for the monthly sample results were obtained from the following report by ERG:

- *Power Plant Monitoring Data Collected under Clean Water Act Section 308 Authority ("CWA 308 Monitoring Data") Sampling Episodes 6565 – 6575* (March 2012)

Belews Creek Steam Station and Allen Steam Station long-term data were obtained from ELG Docket under the following titles:

- *Industry Provided Sampling Data from Duke Energy's Belews Creek Steam Station,* EPAHQ-OW-2009-0819-1226, DCN SE1808
- *Industry Provided Sampling Data from Duke Energy's Allen Steam Station,* EPA-HQ-OW2009-0819-1227, DCN SE1809

EPA also obtained long-term data from a settling pond at Roxboro. These data were obtained from ELG Docket under the following title:

- *State Provided Sampling Data from Progress Energy's Roxboro Plant,* EPA-HQ-OW-2009- 0819-1236, DCN SE1812

When data were reported with a qualifier flag of J, meaning the result was above the method detection limit (MDL) but less than the quantitation limit, the data were used in EPRI's calculations. For the analytes that were not detected, EPRI used half the method detection limit to calculate pollutant reduction.

In some cases, concentration increased through treatment. For example, the magnesium concentration in the averaged influent of chemical precipitation (effluent of the settling ponds) is greater than the magnesium concentration in the averaged CP effluent (from 2,950,000 μg/L in the chemical precipitation influent to 3,450,000 μg/L in the chemical precipitation effluent. For the purposes of this estimate, EPRI substituted "0" for all negative removals.

Each of the four monthly samples was used in EPRI's calculations. The four-day event sampling results were averaged to represent a fifth month. EPRI incorporated the long-term self monitoring data for Allen and Belews Creek according to EPA's methodology. Per page 10-12 of the *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [EPA, 2013b]:

"In cases where an analyte was represented in the long-term self-monitoring data provided by the plant, the EPA sampling, and the CWA 308 monitoring data, EPA averaged all sample results to calculate a plant-level average concentration for each analyte. When combining the industry self-monitoring data with EPA's sampling results (both four-day EPA sampling and CWA 308 monitoring), there were some instances of overlap with two sample results occurring on the same day. In these cases, the two results were averaged together to calculate one average concentration for each day of sampling before calculating an average concentration for each analyte."

In 2007, EPA sampled FGD wastewater at the following four facilities with existing FGD wastewater treatment systems:

- Tampa Electric Company's Big Bend Station
- Homer City Generation L.P.'s Homer City Power Plant
- Ohio Power Company's Mitchell Plant
- Tennessee Valley Authority's Widow's Creek Fossil Plant

Three of these facilities use chemical precipitation and one facility uses settling ponds as shown in Table G-3. One facility also has aerobic biological treatment that follows the chemical precipitation treatment. None of these treatment technologies were considered optimized; therefore, only the untreated and settled data were used in EPRI's evaluation. The same parameters were analyzed in the 2007 sampling episode as in the 2010 sampling episodes. Different sampling methods, however, were occasionally used during the 2007 and 2010 sampling episodes. Whenever available, EPRI used 2007 sample concentrations data with the same method as in the 2010 sampling episode.

Table G-3
Summary of treatment systems by plant for EPA's 2007 sampling studies

	Settling Pond	Chemical Precipitation					Biological Treatment		
		Equalization	Desaturation	Metals Removal (Organo- sulfide addition)	Clarification	Filtration	SBR	ABMet®	Aerobic
Big Bend		X	X		X	X			
Homer City		X	X		X	X			X
Mitchell		X	X		X				
Widow's Creek	X								

ABMet® = Advanced Biological Metals Removal Process (for selenium)
SBR = sequencing batch reactor (for nitrogen removal)

Data from these site visits were obtained from the ELG Docket under the following titles:

- *Sampling Episode Report Tampa Electric Company's Big Bend Station Apollo Beach, FL, Episode 6547,* EPA-HQ-OW-2009-0819-0820, DCN SE02103 [ERG. 2008]
- *Sampling Episode Report EME Homer City Generation L.P.'s Homer City Power Plant, Homer City, PA Episode 6548,* EPA-HQ-OW-2009-0819-0821, DCN SE02104 [ERG, 2008]
- *Sampling Episode Report Ohio Power Company's Mitchell Plant Moundsville, WV, Sampling Episode 6550,* EPA-HQ-OW-2009-0819-0823, DCN02106 [ERG, 2008]
- *Sampling Episode Report Tennessee Valley Authority's Widows Creek Fossil Plant Stevenson, AL, Sampling Episode 6549,* EPA-HQ-OW-2009-0819-0822, DCN SE02105 [ERG, 2008]

In 2015 EPA released the Analytical Database for the Steam Electric Rulemaking which EPRI obtained from the ELG Docket. This database included newer data (sampling data after June 2011) than the data described above, which was used by EPRI in 2013 to comment on the ELG. This newer analytical data included:

- American Electric Power's Mountaineer Plant (CP Effluent)
- Allegheny Energy's Hatfield's Ferry Power Station (CP Effluent)
- RRI Energy's Keystone Generating Station (CP Effluent)

- We Energies' Pleasant Prairie Power Plant (CP Effluent)
- Duke Energy's Miami Fort Station (CP Effluent)
- Duke Energy's Belews Creek Steam Station (CP Effluent*, Biological Effluent)
- Duke Energy's Allen Steam Station (CP Effluent*, Biological Effluent)

*CP Effluent from Belews Creek and Allen were only used to determine removal across biological treatment. They were not used for the industry average CP removal because the CP at those sites was not optimized.

Data from these site visits were obtained from the ELG Docket under the following title: *Analytical Database for the Steam Electric Rulemaking* – EPA-HQ-OW-2009-0819-5640, DCN SE05359

G.1.2.4 Settled FGD wastewater

EPA only has one data point from its 2010 sampling of an actual settling pond, Roxboro, and one data point from its 2007 sampling, Widows Creek, because the remaining facilities EPA sampled appears to have not use a settling pond in their FGD wastewater treatment. Therefore, following EPA's methodology, EPRI estimated the characterization (mass and TWPE) of "settled FGD wastewater" to compare the incremental pollutant reduction of the three treatment alternatives with removal from settling ponds.

For metals, EPRI used the same methodology to calculate settling pond effluent as ERG appears to have for EPA which ERG describes in its memo titled, "Technology Option Loads Calculation Analysis for Steam Electric Detailed Study" [ERG, 2009]. It was assumed that a settling pond would only remove metals present in the particulate phase of the sample, not in the dissolved phase. ERG also assumed that the settling pond would achieve an effluent TSS concentration of 30 milligrams per liter (mg/L), which is the current 30-day average effluent limit set in 40 Code of Federal Regulations (CFR) Part 423 for the best practicable control technology currently available (BPT).

The total settling pond effluent concentration for each pollutant is equal to the sum of the contribution of that pollutant from the solids present in the wastewater and the concentration of that pollutant dissolved in the wastewater. Only the four-day data were used in this calculation because this method requires both the total and the dissolved concentrations in the wastewater, and dissolved data were not collected as part of monthly sampling. The following equation was used to perform this calculation:

$$C_{Settling}\ (\mu g/L) = C_{Dry}\ (mg/kg) \times 30\ mg/L \times 0.000001\ kg/mg \times 1{,}000\ \mu g/mg + C_{Dissolved}\ (\mu g/L)$$

Where (when CDry data was not included in the data set):

C_{Dry} (mg/kg) = {[C_{Total} (µg/L) – $C_{Dissolved}$ (µg/L)] x 1,000,000 mg/kg} / [C_{TSS} (mg/L) x 1,000 µg/mg]

C = concentration

mg/L = milligrams per liter

µg/L = micrograms per liter

µg/mg = micrograms per milligram

Settling pond effluent classical concentrations were handled following EPA's methodology as described on page 10-9 in the *Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [EPA, 2013a]. Namely, chloride appears to no have established removal through the settling process and was equal to the settling pond influent. Ammonia, cyanide, nitrate/nitrite, and sulfate were not calculated. However, following EPA's assumption, cyanide and nitrate/nitrite were set equal to the calculated chemical precipitation effluent.

G.1.3 Calculation of average concentration of FGD wastewater

EPRI used the EPA's sample data described in the section above to calculate the average concentration of parameters in FGD wastewater per coal type used.

G.1.3.1 GP influent and effluent

EPRI used the settled data from the 12 plants that EPA sampled (4 in 2007 and 8 in 2010) to calculate CP influent. As described above, EPA's methodology of calculating settled FGD wastewater appears to have used on the raw data from the plants that did not have a settling pond. Out of the 12 plants, Miami Fort, Keystone, Allen, Belews Creek, Homer City, Widows Creek, Mitchell, Roxboro, and Dickerson settled data were averaged together to characterize CP influent for plants that use bituminous coal as fuel. Hatfield's Ferry and Big Bend settled data were averaged together to characterize CP influent for "Blend/Other" plants. Pleasant Prairie CP settled was used to characterize CP influent for plants that use Powder River Basin (PRB) or subbituminous coal as fuel.

The effluent from CP systems was calculated from the Mountaineer Plant, Hatfield's Ferry, Keystone, Miami Fort, and Pleasant Prairie data. CP effluent for Mountaineer Plant, Keystone and Miami Fort were averaged to represent plants that use bituminous coal as fuel. CP effluent for Hatfield's Ferry was used to represent "Blend/Other" plants. And CP effluent of Pleasant Prairie was used to represent plants that use PRB coal as fuel.

The removal was calculated by coal type. The bituminous coal removal across CP was calculated by subtracting the bituminous CP influent by the bituminous CP effluent. The blend coal removal across CP was calculated by subtracting the blend coal CP influent by the blend coal CP effluent. And the PRB removal was calculated by subtracting the PRB CP influent by the PRB CP effluent.

Table G-4 shows the average CP influent, effluent, and removal by coal type in µg/L for each parameter. Each of the parameters was then multiplied by the toxic weighting factor (TWF) to calculate as µg/L times TWF (TWµg/L).

Table G-4
CP influent and effluent concentration and TWµg/L
(Page 1 of 6. This table has been formatted with row and column labels because it spans multiple pages.)

		A	B	C	D	E	F	G	H	I	J
		Untreated Settled									
		MF Settled Effluent (Bit)	KY Settled Effluent (Bit)	AL Settled Effluent (Bit)	BC Settled Effluent (Bit)	HC Settled Effluent (Bit)	WC Settled Effluent (Bit)	MI Settled Effluent (Bit)	RX Settled Effluent (Bit)	DI Settled Effluent (Bit)	Settled Effluent (Bit Average)
	Analyte	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L
1	Aluminum	10,328	912	965	813	677	111	98	345	781	1,670
2	Antimony	3	0	3	2	0	12	2	74	4	11
3	Arsenic	7	5	11	6	27	48	20		4	16
4	Barium	162	390	374	668	176	179	488	387	186	334
5	Beryllium	6	0	1	0	11	3	6	1	0	3
6	Cadmium	415	85	2	3	25	4	1	2	23	62
7	Calcium	656,110	5,077,168	1,930,002	3,310,305	1,992,774	986,500	2,352,787		2,025,000	2,291,331
8	Chloride	9,500,000	15,150,000	3,900,000	7,600,000	11,800,000	1,115,000	7,200,000		7,675,000	7,992,500
9	Chromium	7	4	3	6	11	8	41	82	5	19
10	Cobalt	393	475	22	23	201	25	25	11	72	139
11	Copper	69	5	13	4	13	2	11	7	17	16
12	Hexavalent Chromium	1	1	1	1	1				1	1
13	Iron	1,193	2,435	909	951	1,909	50	298	925	1,077	1,083
14	Lead	1	1	2	2	1	1	1	11	2	2
15	Manganese	120,008	450,037	3,382	4,561	173,117	623	27,904	1,690	9,774	87,899
16	Mercury	2	1	1	15	1	0	1	1	0	2
17	Molybdenum	113	1	18	23	31	1,500	22	43	216	219
18	Nickel	1,977	2,179	82	128	1,453	36	434	200	4	721
19	Nitrate/Nitrite						95				95
20	Selenium	316	1,228	333	720	591	208	449	1,770	179	644

Table G-4 (continued)
CP influent and effluent concentration and TWµg/L

(Page 2 of 6. This table has been formatted with row and column labels because it spans multiple pages.)

		A	B	C	D	E	F	G	H	I	J
		Untreated Settled									
		MF Settled Effluent (Bit)	KY Settled Effluent (Bit)	AL Settled Effluent (Bit)	BC Settled Effluent (Bit)	HC Settled Effluent (Bit)	WC Settled Effluent (Bit)	MI Settled Effluent (Bit)	RX Settled Effluent (Bit)	DI Settled Effluent (Bit)	Settled Effluent (Bit Average)
	Analyte	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L
21	Silver	0	0	0	0	1	1	1	0	0	0
22	Sodium	405,035	315,018	33,742	481,896	1,439,977	69,450	323,959		192,500	407,697
23	Sulfate					6,920,000	2,055,000	1,640,000	1,236,538		2,962,885
24	Thallium	32	28	1	4	23	11	4	4	1	12
25	Tin	4	2	2	7	15	15	15		3	8
26	Titanium	5	10	23	21	8	5	7		36	14
27	Vanadium	20	5	4	4	12	42	11	5	12	13
28	Zinc	7,787	76	40	36	39	5	162	50	714	990
29	Biochemical Oxygen Demand						7750				7,750
30	Chemical Oxygen Demand										
31	Total Suspended Solids					30,000	8,000	30,000			22,667
32	Total Dissolved Solids	58,250,000	35,500,000	9,475,000	17,250,000	23,200,000	5,830,000	18,100,000		52,000,000	27,450,625
33	Total Kjeldahl Nitrogen						2,505				2,505
34	Total Phosphorus					520	12	75			202
35	Ammonia as N						220				220
36	Boron	722,528	395,024	72,272	147,537	253,932	31,450	231,988	80,244	187,526	235,834
37	Magnesium	9,050,630	2,825,140	472,936	695,388	3,099,233	189,000	1,370,410		1,450,463	2,394,150
38	Cyanide										
39	Total										16,381,297

Table G-4 (continued)
CP influent and effluent concentration and TWµg/L

(Page 3 of 6. This table has been formatted with row and column labels because it spans multiple pages.)

		K	L	M	N	O	P	Q	R	S	T	U	V	W
		Untreated Settled (continued)				CP Effluent						CP Removal		
		HF Settled Effluent (Blend)	BB Settled Effluent (Blend)	Settled Effluent (Blend Average)	P4 Settled Effluent (PRB/ Sub-bit Average)	KY CP Effluent (Bit)	MF CP Effluent (Bit)	MP CP Effluent (Bit)	CP Effluent (Bit Average)	HF CP Effluent (Blend - Average)	P4 CP Effluent (PRB/ Sub-bit Average	CP Removal Bit	CP Removal Blend	CP Removal PRB/ Sub-bit
	Analyte	µg/L	µg/L	µg/L	µg/L		µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L
1	Aluminum	1,098	213	**656**	**1,293**	6	45		**25**	**124**	**75**	1,645	531	1,219
2	Antimony	8	22	**15**	**4**	0	5		**3**	**8**	**3**	8	7	1
3	Arsenic	9	137	**73**	**9**	5	13	3	**7**	**68**	**8**	9	5	1
4	Barium	162	1,819	**990**	**97**	230	122		**176**	**136**	**66**	159	854	31
5	Beryllium	3	3	**3**	**1**	0	0		**0**	**0**	**0**	3	2	1
6	Cadmium	365	190	**278**	**5**	3	1		**2**	**9**	**1**	60	269	4
7	Calcium	795,920	4,483,400	**2,639,660**	**553,743**	4,695,000	928,500		**2,811,750**	**1,348,182**	**687,000**	0	1,291,478	
8	Chloride	7,092,500	24,200,000	**15,646,250**	**1,800,000**	13,650,000	13,650,000	6,755,000	3,283,750	**7,896,250**	**8,117,803**	**2,310,000**	96,250	7,528,447
9	Chromium	5	163	**84**	**12**	1	1	12		**7**	**4**	**2**	12	80
10	Cobalt	348	26	**187**	**115**	1	1	1		**1**	**1**	1	138	186
11	Copper	14	21	**17**	**39**	0	0	1		**1**	**4**	**4**	15	13
12	Hexavalent Chromium	1	24	**12**	**1**	1	1	7		**4**	**4**	1	0	9
13	Iron	856	192	**524**	**3,865**	76	76	142		**109**	**114**	**117**	974	410
14	Lead	1	5	**3**	**3**	0	0	0		**0**	**7**	**0**	2	0
15	Manganese	85,257	9,684	**47,471**	**69,789**	35,450	35,450	506		**17,978**	**3,329**	**11,240**	69,922	44,142
16	Mercury	1	0	**1**	**20**	0	0	0	0	0	**0**	**0**	2	0
17	Molybdenum	515	581	**548**	**48**	36	36	226		**131**	**385**	**50**	88	163
18	Nickel	1,126	1,039	**1,083**	**940**	8	8	3		**6**	**14**	**5**	716	1,069
19	Nitrate/Nitrite					20,510	20,510	64,400	29,218	**38,043**	**116,800**	**182,000**	0	0
20	Selenium	549	3,281	**1,915**	**3,816**	139	139	547	384	**357**	**631**	**2,221**	287	1,284

Table G-4 (continued)
CP influent and effluent concentration and TWμg/L

(Page 4 of 6. This table has been formatted with row and column labels because it spans multiple pages.)

		K	L	M	N	O	P	Q	R	S	T	U	V	W
		Untreated Settled (continued)				CP Effluent						CP Removal		
		HF Settled Effluent (Blend)	BB Settled Effluent (Blend)	Settled Effluent (Blend Average)	P4 Settled Effluent (PRB/ Sub-bit Average)	KY CP Effluent (Bit)	MF CP Effluent (Bit)	MP CP Effluent (Bit)	CP Effluent (Bit Average)	HF CP Effluent (Blend - Average)	P4 CP Effluent (PRB/ Sub-bit Average	CP Removal Bit	CP Removal Blend	CP Removal PRB/ Sub-bit
	Analyte	μg/L	μg/L	μg/L	μg/L		μg/L	μg/L	μg/L	μg/L	μg/L	μg/L	μg/L	μg/L
21	Silver	549	3,281	1,915	3,816	139	547	384	357	631	2,221	287	1,284	1,595
22	Sodium	0	10	5	0	0	0		0	7	0	0	0	0
23	Sulfate	447,523	1,973,380	1,210,452	490,000	263,000	530,500		396,750	464,500	506,500	10,947	745,952	0
24	Thallium		3,590,000	3,590,000		1,565,000	12,140,000		6,852,500	4,115,750	12,620,000	0	0	0
25	Tin	28	39	33	10	9	8		8	18	1	4	16	8
26	Titanium	2	15	9	16	2	2		2	2	3	6	6	13
27	Vanadium	57	112	84	15	3	17		10	24	1	3	61	14
28	Zinc	2,332	61	1,197	101	7	9		8	22	15	982	1,175	86
29	Biochemical Oxygen Demand					1,391	3,294		2,343		1,009	5,408	0	0
30	Chemical Oxygen Demand					394,000	566,000		480,000	373,913	363,000	0	0	0
31	Total Suspended Solids		30,000	30,000		3,370	9,030		6,200	16,991	1,750	16,467	13,009	0
32	Total Dissolved Solids	30,750,000	44,600,000	37,675,000	24,250,000	22,600,000	29,500,000		26,050,000	23,009,137	20,500,000	1,400,625	14,665,863	3,750,000
33	Total Kjeldahl Nitrogen					27,100	32,750		29,925	31,367	120,300	0	0	0
34	Total Phosphorus		355	355		932	227		580	53	73	0	302	0
35	Ammonia as N					8,020	13,205	3,425	8,217	1,861	5,510	0	0	0
36	Boron	322,510	618,048	470,279	12,991	272,000	387,500		329,750	215,580	12,965	0	254,699	26
37	Magnesium	5,200,510	4,114,346	4,657,428	3,927,203	2,025,000	5,435,000		3,730,000	3,188,462	3,545,000	0	1,468,966	382,203
38	Cyanide					92	3,305		1,698	129	241	0	0	0
39	Total			28,269,634	6,864,179				22,114,302	17,605,398	20,003,405	182,240	11,340,149	448,658

Table G-4 (continued)
CP influent and effluent concentration and TWμg/L

(Page 5 of 6. This table has been formatted with row and column labels because it spans multiple pages.)

		X	Y	Z	AA	BB	CC	DD	EE	FF	HH
			Settled Effluent			CP Effluent			CP Removal		
			Settled Effluent (Bit Average)	Settled Effluent (Blend Average)	P4 Settled Effluent (PRB/Sub-bit Average)	Settled Effluent (Bit Average)	Settled Effluent (Blend Average)	P4 Settled Effluent (PRB/Sub-bit Average)	Settled Effluent (Bit Average)	Settled Effluent (Blend Average)	P4 Settled Effluent (PRB/Sub-bit Average)
	Analyte	TWF	TWμg/L	TWμg/L	TWμg/L	TWμg/L	TWμg/L	TWμg/L	TWμg/L	TWμg/L	TWμg/L
1	Aluminum	0.064691216	108	42	84	2	8	5	106	34	79
2	Antimony	0.01225	0	0	0	0	0	0	0	0	0
3	Arsenic	3.469333333	55	253	30	25	235	26	30	18	3
4	Barium	0.001990757	1	2	0	0	0	0	0	2	0
5	Beryllium	1.056603774	3	3	1	0	0	0	3	3	1
6	Cadmium	22.7584	1,412	6,320	112	37	197	14	1,375	6,123	98
7	Calcium	0.000028	64	74	16	79	38	19	0	36	0
8	Chloride	0.0000243	194	380	44	192	197	56	2	183	0
9	Chromium	0.075696709	1	6	1	1	0	0	1	6	1
10	Cobalt	0.114285714	16	21	13	0	0	0	16	21	13
11	Copper	0.623482222	10	11	24	0	3	3	9	8	22
12	Hexavalent Chromium	0.516557576	1	6	1	2	2	1	0	4	0
13	Iron	0.0056	6	3	22	1	1	1	5	2	21
14	Lead	2.24	5	7	7	1	16	1	4	0	6
15	Manganese	0.102666667	9,024	4,874	7,165	1,846	342	1,154	7,179	4,532	6,011
16	Mercury	110.0327273	270	60	2,215	20	27	22	251	33	2,193
17	Molybdenum	0.201438849	44	110	10	26	78	10	18	33	0
18	Nickel	0.108914308	79	118	102	1	2	1	78	116	102
19	Nitrate/Nitrite	0.0032	0	0	0	122	374	582	0	0	0
20	Selenium	1.121344	722	2,147	4,279	400	707	2,491	322	1,440	1,789

Table G-4 (continued)
CP influent and effluent concentration and TWµg/L

(Page 6 of 6. This table has been formatted with row and column labels because it spans multiple pages.)

		X	Y	Z	AA	BB	CC	DD	EE	FF	HH
			Settled Effluent			CP Effluent			CP Removal		
			Settled Effluent (Bit Average)	Settled Effluent (Blend Average)	P4 Settled Effluent (PRB/Sub-bit Average)	Settled Effluent (Bit Average)	Settled Effluent (Blend Average)	P4 Settled Effluent (PRB/Sub-bit Average)	Settled Effluent (Bit Average)	Settled Effluent (Blend Average)	P4 Settled Effluent (PRB/Sub-bit Average)
	Analyte	TWF	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L
21	Silver	2.854901961	8	85	5	5	114	5	3	0	0
22	Sodium	0.301075269	2	7	3	2	3	3	0	4	0
23	Sulfate	0.029319372	17	20	0	38	23	71	0	0	0
24	Thallium	0.28	34	96	27	24	51	4	11	44	23
25	Tin	0.046886	2	3	5	1	1	1	2	2	4
26	Titanium	0	0	0	1	0	0	0	0	0	1
27	Vanadium	0	4	24	4	3	7	0	1	17	4
28	Zinc	0	46	56	5	0	1	1	46	55	4
29	Biochemical Oxygen Demand	0	0	0	0	0	0	0	0	0	0
30	Chemical Oxygen Demand	0	0	0	0	0	0	0	0	0	0
31	Total Suspended Solids	0	0	0	0	0	0	0	0	0	0
32	Total Dissolved Solids	0.00111	0	0	0	0	0	0	0	0	0
33	Total Kjeldahl Nitrogen	0.008341667	0	0	0	0	0	0	0	0	0
34	Total Phosphorus	0.000865533	0	0	0	0	0	0	0	0	0
35	Ammonia as N	1.116923077	0	0	0	9	2	6	0	0	0
36	Boron		1,967	3,923	108	2,751	1,798	108	0	2,125	0
37	Magnesium	2.854901961	2,072	4,031	3,399	3,228	2,760	3,068	0	1,271	331
38	Cyanide	0.301075269	0	0	0	1,897	145	269	0	0	0
39	Total	0.029319372	16,170	22,683	17,681	10,712	7,130	7,922	9,463	16,114	10,705

Table G-4 (continued)
CP influent and effluent concentration and TWµg/L

Table notes:

AL – Allen Steam Station
BB – Big Bend Station
BC – Belews Creek Steam Station
Bit = bituminous
DI – Dickerson Generating Station
HC – Homer City Power Plant
HF – Hatfield's Ferry Station
KY – Keystone Generating Station
MF – Miami Fort Station
MI – Mitchell Plant
MP – Mountaineer Plant
P4 – Pleasant Prairie Power Plant
RX – Roxboro Plant
Sub-bit = sub-bituminous
WC – Widow's Creek Fossil Plant
µg/L total do not include biochemical oxygen demand, chemical oxygen demand, total suspended solids, and total dissolved solids

G.1.3.2 Biological influent and effluent

The removal via biological treatment was first calculated at both Allen and Belews Creek for each parameter. To avoid artificial removals due to the mixing of plants' data (Hatfield's Ferry, Keystone, Miami Fort, and Pleasant Prairie as influent and Allen and Belews Creek as effluent), parameters that were not treated at Allen or Belews Creek were assessed. Six parameters (magnesium, cyanide, boron, manganese, chloride, sulfate) that had little to no removal at Allen and Belews Creek are shown in Table G-5. These parameters were then removed from the industry pollutant reduction calculation This is consistent with EPA's methodology in past ELGs where EPA has excluded parameters with insignificant removal. Mountaineer Plant biological influent and effluent data was excluded from the analysis due to the CP effluent being combined with landfill leachate. Therefore, the biological effluent data would not represent FGD stream only but a combination of FGD and landfill leachate.

Table G-5
Biological parameters removed for industry pollutant reduction calculation

	Allen				Belews Creek			
	Biological Influent (µg/L)	Biological Effluent (µg/L)	Removal (µg/L)	Removal (%)	Biological Influent (µg/L)	Biological Effluent (µg/L)	Removal (µg/L)	Removal (%)
Magnesium	512,423	493,605	18,818	4	722,143	731,190	None	None
Cyanide	88	104	None	None	33	33	0	1
Boron	108,641	97,130	11,511	11	187,847	179,821	8,026	4
Manganese	234	381	None	None	2,649	2,930	None	None
Chloride	2,529,167	2,552,209	None	None	6,812,195	8,238,895	None	None
Sulfate	1,726,667	1,695,164	31,503	2	1,293,333	1,432,000	None	None

EPRI calculated the influent to the biological treatment system as the average of the CP effluent by coal type from Miami Fort, Keystone, Hatfield's Ferry, and Pleasant Prairie. Miami Fort and Keystone CP effluent data were averaged and used for biological treatment influent for plants that use bituminous coal as fuel. Hatfield's Ferry CP effluent data were used for biological influent for plants that use a blend of coal as fuel. Pleasant Prairie CP effluent data were used for biological influent for plants that use PRB coal as fuel.

Since Belews Creek and Allen use only bituminous coal as fuel, the effluent from the biological treatment system was calculated as the average of the biological effluent from Belews Creek and Allen and was applied to all plants regardless of coal type. The monthly, 4-day and long-term data were used to calculate average concentration for each pollutant for the biological system effluent. Incorporation of the data is described in the 'Summary of Data Used for the Pollutant Reduction Evaluation" section above.

The biological treatment system removal for the bituminous coal type was calculated by taking the biological influent average of the bituminous plants (Miami Fort and Keystone) and subtracting it by the average of the biological effluent (Allen and Belews Creek). The removal for the blend coal type was calculated by taking the biological influent of Hatfield's Ferry and subtracting it by the average of the biological effluent. The removal for PRB coal type was calculated by taking the biological influent of Pleasant Prairie and subtracting it by the average of the biological effluent.

Table G-6 shows the average Biological influent, effluent, and removal by coal type in ug/L for each parameter. Each of the parameters was then multiplied by the toxic weighting factor (TWF) to calculate a TWµg/L.

Table G-6
Biological influent and effluent concentrations and TWµg/L
(Page 1 of 4. This table has been formatted with row and column labels because it spans multiple pages.)

		A	B	C	D	E	F	G
		Settled Effluent			Biological Effluent	CP Removal		
		CP Effluent (Bit Average)	HF CP Effluent (Blend Average)	P4 CP Effluent (PRB/ Sub-bit Average)	2 Biological Effluent (AL, BC)	Biological Removal Bit	Biological Removal Blend	Biological Removal PRB/Sub-bit
	Analyte	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L
1	Aluminum	25	124	75	25	1	100	50
2	Antimony	3	8	3	2	1	6	1
3	Arsenic	7	68	8	12	0	56	0
4	Barium	176	136	66	324	0	0	0
5	Beryllium	0	0	0	2	0	0	0
6	Cadmium	2	9	1	4	0	5	0
7	Calcium	2,811,750	1,348,182	687,000	2,449,197	362,553	0	0
8	Chloride	7,896,250	8,117,803	2,310,000	5,395,552	-	-	-
9	Chromium	7	4	2	3	3	1	0
10	Cobalt	1	1	1	1	0	0	0
11	Copper	1	4	4	7	0	0	0
12	Hexavalent Chromium	4	4	1	1	3	3	0
13	Iron	109	114	117	833	0	0	0
14	Lead	0	7	0	1	0	6	0
15	Manganese	17,978	3,329	11,240	1,656	-	-	-
16	Mercury	0	0	0	0	0	0	0
17	Molybdenum	131	385	50	13	118	373	38
18	Nickel	6	14	5	16	0	0	0
19	Nitrate/Nitrite	38,043	116,800	182,000	1,213	36,829	115,587	180,787
20	Selenium	357	631	2,221	8	349	623	2,213

Table G-6 (continued)
Biological influent and effluent concentrations and TWµg/L
(Page 2 of 4. This table has been formatted with row and column labels because it spans multiple pages.)

		A	B	C	D	E	F	G
		Settled Effluent			Biological Effluent	CP Removal		
		CP Effluent (Bit Average)	HF CP Effluent (Blend Average)	P4 CP Effluent (PRB/ Sub-bit Average)	2 Biological Effluent (AL, BC)	Biological Removal Bit	Biological Removal Blend	Biological Removal PRB/Sub-bit
	Analyte	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L	µg/L
21	Silver	0	7	0	4	0	3	0
22	Sodium	396,750	464,500	506,500	40,276	356,474	424,224	466,224
23	Sulfate	6,852,500	4,115,750	12,620,000	1,563,582			
24	Thallium	8	18	1	1	8	17	1
25	Tin	2	2	3	2	0	0	1
26	Titanium	4	1	1	8	0	0	0
27	Vanadium	10	24	1	1	9	22	0
28	Zinc	8	22	15	6	2	16	9
29	Biochemical Oxygen Demand	2,343	0	1,009	1193.5	1149	0	0
30	Chemical Oxygen Demand	480,000	373,913	363,000	158,925	321,075	214,988	204,075
31	Total Suspended Solids	6,200	16,991	1,750	2,605	3,595	14,386	0
32	Total Dissolved Solids	26,050,000	23,009,137	20,500,000	13,186,923	12,863,077	9,822,214	7,313,077
33	Total Kjeldahl Nitrogen	29,925	31,367	120,300	11,890	18,035	19,477	108,410
34	Total Phosphorus	580	53	73	116	463	0	0
35	Ammonia as N	8,217	1,861	5,510	4,981	3,235	0	529
36	Boron	329,750	215,580	12,965	138,476			
37	Magnesium	3,730,000	3,188,462	3,545,000	612,398			
38	Cyanide	1,698	129	241	69			
39	Total	22,114,302	17,605,398	20,003,405	10,220,679	778,084	560,518	758,262

Table G-6 (continued)
Biological influent and effluent concentrations and TWµg/L
(Page 3 of 4. This table has been formatted with row and column labels because it spans multiple pages.)

		H	I	J	K	L	M	N	O
			Settled Effluent			Biological Effluent	CP Removal		
			CP Effluent (Bit Average)	HF CP Effluent (Blend Average)	P4 CP Effluent (PRB/Sub-bit Average)	2 Biological Effluent (AL, BC)	Biological Removal Bit	Biological Removal Blend	Biological Removal PRB/Sub-bit
	Analyte	TWF	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L
1	Aluminum	0.064691216	2	8	5	2	0	6	3
2	Antimony	0.01225	0	0	0	0	0	0	0
3	Arsenic	3.469333333	25	235	26	43	0	193	0
4	Barium	0.001990757	0	0	0	1	0	0	0
5	Beryllium	1.056603774	0	0	0	2	0	0	0
6	Cadmium	22.7584	37	197	14	85	0	112	0
7	Calcium	0.000028	79	38	19	69	10	0	0
8	Chloride	0.0000243	192	197	56	131			
9	Chromium	0.075696709	1	0	0	0	0	0	0
10	Cobalt	0.114285714	0	0	0	0	0	0	0
11	Copper	0.623482222	0	3	3	4	0	0	0
12	Hexavalent Chromium	0.516557576	2	2	1	0	2	2	0
13	Iron	0.0056	1	1	1	5	0	0	0
14	Lead	2.24	1	16	1	2	0	14	0
15	Manganese	0.102666667	1,846	342	1,154	170			-
16	Mercury	110.0327273	20	27	22	29	0	0	0
17	Molybdenum	0.201438849	26	78	10	3	24	75	8
18	Nickel	0.108914308	1	2	1	2	0	0	0
19	Nitrate/Nitrite	0.0032	122	374	582	4	118	370	579
20	Selenium	1.121344	400	707	2,491	8	392	699	2,482

Table G-6 (continued)
Biological influent and effluent concentrations and TWµg/L
(Page 4 of 4. This table has been formatted with row and column labels because it spans multiple pages.)

		H	I	J	K	L	M	N	O
			Settled Effluent			Biological Effluent	CP Removal		
			CP Effluent (Bit Average)	HF CP Effluent (Blend Average)	P4 CP Effluent (PRB/Sub-bit Average)	2 Biological Effluent (AL, BC)	Biological Removal Bit	Biological Removal Blend	Biological Removal PRB/Sub-bit
	Analyte	TWF	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L	TWµg/L
21	Silver	16.47072824	5	114	5	60	0	54	0
22	Sodium	0.00000549	2	3	3	0	2	2	3
23	Sulfate	0.0000056	38	23	71	9			
24	Thallium	2.854901961	24	51	4	2	22	49	2
25	Tin	0.301075269	1	1	1	1	0	0	0
26	Titanium	0.029319372	0	0	0	0	0	0	0
27	Vanadium	0.28	3	7	0	0	2	6	0
28	Zinc	0.046886	0	1	1	0	0	1	0
29	Biochemical Oxygen Demand	0	0	0	0	0	0	0	0
30	Chemical Oxygen Demand	0	0	0	0	0	0	0	0
31	Total Suspended Solids	0	0	0	0	0	0	0	0
32	Total Dissolved Solids	0	0	0	0	0	0	0	0
33	Total Kjeldahl Nitrogen	0	0	0	0	0	0	0	0
34	Total Phosphorus	0	0	0	0	0	0	0	0
35	Ammonia as N	0.00111	9	2	6	6	4	0	1
36	Boron	0.008341667	2,751	1,798	108	1,155			
37	Magnesium	0.000865533	3,228	2,760	3,068	530			
38	Cyanide	1.116923077	1,897	145	269	77			
39	Total		10,712	7,131	7,922	2,399	**575**	**1,583**	**3,077**

Table G-6 (continued)
Biological influent and effluent concentrations and TWµg/L

Table notes:

AL – Allen Steam Station
BC – Belews Creek Steam Station
Bit = bituminous
HF – Hatfield's Ferry Power Station
P4 – Pleasant Prairie Power Plant Sub-bit = sub-bituminous
µg/L totals do not include biochemical oxygen demand, chemical oxygen demand, total suspended solids, and total dissolved solids

G.1.3.3 CP + VIP influent and effluent

The pollutant reduction of VIP was calculated based on the current treatment in place. For plants that currently have settling ponds, the pollutant reduction of CP + VIP was calculated as the average settling pond effluent by coal type. For plants that currently have CP treatment, the pollutant reduction of CP + VIP was calculated as the average CP effluent by coal type. For plants that currently have biological treatment, the pollutant reduction of CP + VIP was calculated as the average biological effluent by coal type. This is because the CP + VIP was assumed to be a zero discharge system and therefore the effluent was assumed to have zero TWPE

G.1.4 Calculated pollutant reduction estimates for industry

The same list of plants was used as in the FGD cost calculations. A description of the industry is in Appendix D Section D.1.9.

Table G-7 lists the number of plants and the type of treatment in place.

Table G-7
Description of treatment in place for 68 plants included in industry extrapolation

Treatment in Place	Number of Plants
Plants with Settling Pond	27
Plants with CP (Including plants with Partial and Optimized CP)	32
Plants with Biological Treatment	6
Plant with CP + VIP	3
Total	68

Coal type data were also evaluated from the Questionnaire for the Steam Electric Power Generating Effluent Guidelines for each of the plants included in the industry extrapolation. Data for plants not included in the Questionnaire were evaluated from Energy Information Administration 2016 EIA-923 Monthly Generation and Fuel Consumption Time Series File [EIA, 2016]. Any plants using more than one coal type were grouped as “blend/other” coal. Redacted coal type, lignite, or petroleum coke, were also grouped in as blend/other coal. The breakdown of each coal type is summarized in Table G-8.

Table G-8
Industry extrapolation by coal type

	Flow (GPY)	Percent of Industry
Industry	6,140,000,000	
Bituminous	3,540,000,000	58%
Blend/Other	2,230,000,000	36%
Subbituminous	360,000,000	6%

GPY = gallons per year

Consideration was given to which plants to include in these pollutant reduction calculations. For example, plants with optimized CP treatment already installed were not used in the calculation of the pollutant reduction of CP. The pollutant reduction for each treatment type is summarized in Table G-9.

Table G-9
Pollutant reduction for each treatment type applied in the industry extrapolation

Treatment in Place	CP	Incremental Biological	CP + VIP
Plants with Settling Pond	Full CP pollutant reduction	Full Biological pollutant reduction	Settling pond effluent to zero
Plants with CP (Including plants with Partial and Optimized CP)	No pollutant reduction	Full Biological pollutant reduction	CP effluent to zero
Plants with Biological Treatment	No pollutant reduction	No pollutant reduction	Biological effluent to zero
Plant with CP + VIP	No pollutant reduction	No pollutant reduction	No pollutant reduction

The total pollutant reductions from CP + Biological were then calculated by adding the CP + Incremental biological pollutant reductions. The total pollutant reductions from incremental VIP were then calculated by subtracting the CP pollutant reductions from the CP + VIP pollutant reductions.

G.1.4.1 Flow basis

The pollutant reduction of treatment at each plant by coal type was multiplied by the flow at each plant to calculate mass removed. The same plant flows were used as in the FGD cost analysis. The average flows which were used to cost Operation and Maintenance activities were used to calculate pollutant removals on a per plant level. The plant average gallon per minute flows were used and converted to gallons per year by multiplying by the plant's respective capacity factor and 60 minutes per hour, 24 hours per day, 365 days per year. The flow basis for the FGD costs are summarized in Appendix A Section 1.4.1 and Appendix B Section 1.4.1.

G.1.7 Conclusion

A summary of the annualized industry pollutant reductions for each FGD wastewater treatment technology is shown in Table G-10.

Table G-10
Detailed annualized industry pollutant reduction for FGD wastewater treatment

Treatment Type		Number of Plants	Total Flow Rate (BGY)	TWPE Per Year Remove (Millions)	Pounds per Year (Millions)
Chemical Precipitation		27	2.27	0.2	82
Bituminous Plants		14	1.36	0.1	2.1
Blend/Other Plants		9	0.84	0.1	80
PRB/Subbituminous		4	0.06	0.01	0.2
Incremental Biological		59	5.63	0.05	32
Bituminous Plants		35	3.19	0.02	21
Blend/Other Plants		19	2.23	0.03	10
PRB/Subbituminous		5	0.21	0.01	1
Chemical Precipitation + Voluntary Incentive Program Option	TIP =Ponds	27	2.27	0.35	389
	Bituminous Plants	14	1.36	0.18	187
	Blend/Other Plants	9	0.84	0.16	199
	PRB/Sub-bituminous	4	0.06	0.01	3
	TIP = CP	32	3.36	0.26	566
	Bituminous Plants	21	1.83	0.16	338
	Blend/Other Plants	10	1.38	0.08	204
	PRB/Sub-bituminous	1	0.15	0.01	25
	TIP = Biological	6	0.46	0.01	39
	Bituminous Plants	5	0.33	0.01	28
	Blend/Other Plants	0	0	0	0
	PRB/Sub-bituminous	1	0.13	0.003	11
	Total	65	6.08	0.62	994

BGY = billion gallons per year
TIP = treatment in place

Table G-11, presented at the beginning of this appendix as Table G-1, shows a summary of the TWPE removal to the industry for each treatment and coal type. Chemical precipitation with biological treatment is the sum of the chemical precipitation and incremental biological pollutant G-29 reduction. Incremental VIP is the pollutant reduction of chemical precipitation and VIP pollutant reduction minus the pollutant reduction of chemical precipitation.

Table G-11
Annualized industry pollutant reduction for FGD wastewater treatment

Treatment Type		TWPE per Year Removed	Pounds per year Removed
Chemical Precipitation	Total	227,000	82,200,000
Biological	Incremental	50,100	32,500,000
Chemical Precipitation + Biological	Total	277,000	115,000,000
Voluntary Incentive Program Option	Incremental	391,000	912,000,000
Chemical Precipitation + Voluntary Incentive Program Option	Total	618,000	994,000,000

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 1

Comment Excerpt:

Key Comments on FGD BAT Wastewater Treatment Cost

EPA's calculated total annualized cost for treatment of FGD wastewater via chemical precipitation (CP) and biological systems are lower than EPRI's by 70 percent due to a number of factors, including:

- EPA apparently underestimated the peak FGD wastewater design flow used to size equipment. When only average FGD flow was available, EPRI used an adjustment factor, since wastewater treatment equipment must be sized to accommodate the peak flow so that the treatment system can consistently meet limits. •
- EPA appears to have underestimated the cost factors that were used to create a total installed cost estimate for each individual plant. EPRI used cost factors more typical of an industry standard engineering estimate.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 66

Comment Excerpt:

D —APPENDIX: FGD WASTEWATER TREATMENT COST METHODOLOGY—BRINE SOLIDIFICATION

D.1 Case study evaluation of brine solidification options for flue gas desulfurization wastewater

D.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the cost of chemical softening with vapor-compression evaporation and crystallization (CS + VCE/CRX) treatment of flue gas desulfurization (FGD) wastewater to the steam electric industry, as previously presented in Appendix C.

EPRI has also developed case study cost estimates for three other technology options that, similar to CS + VCE/CRX, have the ability to eliminate direct discharge of FGD wastewater. These three options incorporate FGD wastewater concentration and solidification (i.e., brine encapsulation):

- Chemical precipitation (CP) followed by vapor-compression evaporation and brine solidification (CP + VCE/BS) (Section D.1.2)
- Chemical softening (CS) followed by seawater reverse osmosis and brine solidification (CS + SWRO/BS) (Section D.1.3)
- Chemical precipitation (CP) followed by advanced membrane filtration and brine solidification (CP+ARO/BS) (Section D.1.4)

This technical memorandum describes the method for calculating the cost of treatment for an individual case study plant for each of these technology options. Table D-1 outlines the cost of treatment for a conceptual treatment system for an FGD wastewater flow rate of 300 gallons per minute (gpm) for these options.

Table D-1
Case study treatment costs for a 300 gpm system for one power plant, in June 2018 dollars

Treatment Option	Capital Cost ($M)	Operations and Maintenance Cost [a] ($M per year)	Annualized Cost [b] ($M per year)
CP + VCE/BS [c]	99	12	21
CS + RO/BS [d]	102	30	39
CP + ARO/BS[e]	127	49	61

M = million
$ = U.S. dollars
[a] Plant assumed to have a capacity factor of 0.51.
[b] Annualized cost based on a 20-year equipment life and 7% interest rate.
[c] System designed with 2x60% redundancy CP system, 2x60% redundancy VCE system and N+1 redundancy pugmills.
[d] System designed with 2x60% redundancy CS system, N+1 redundancy membrane system and N+1 redundancy pugmills.
[e] System designed with 2x60% redundancy CP system, 120% redundancy VSEP + spiral wound RO polishing system and N+1 redundancy pugmills.

D.1.2 Treatment overview of chemical precipitation with vapor-compression evaporation and brine solidification (CP + VCE/BS)

This evaluation considers a treatment option that includes FGD wastewater chemical precipitation followed by thermal evaporation and brine solidification. There are two key differences for this case study, compared to the conceptual design assumed in Appendix C, which include:

- The pre-treatment for this case study assumes chemical precipitation (CP) for solids removal. Full chemical softening (CS), using hydrated lime and soda ash, are not assumed for this case study.
- This case study assumes solidification (i.e., encapsulation) of the evaporator brine as opposed to further concentrating the evaporator brine by using a crystallizer (the latter was assumed in Appendix C for CS + VCE/CRX).

As noted in Appendix C, EPRI has used EPA's definition of untreated FGD wastewater, which most closely aligns with FGD blowdown from a plant that burns eastern bituminous coal. The pretreatment for the assumed FGD wastewater in this case study consists of hydrated lime addition to pH 9 to encourage calcium sulfate precipitation and to reduce the solids concentration fed to the evaporator. The objective of this pre-treatment is solids precipitation only. Pretreatment for this option does not require targeted removal of dissolved hardness parameters (i.e., calcium and magnesium). Therefore, the chemical precipitation (CP) pretreatment needed for this option requires fewer chemicals (e.g., soda ash is not required for calcium removal), a lesser quantity of chemicals (e.g., less hydrated lime is added since magnesium removal is not targeted) and generates fewer solid residuals compared to full softening pretreatment (CS) required for crystallization (Appendix C) or reverse osmosis (Section D.1.3). Precipitation of calcium sulfate is followed by pH neutralization using sulfuric acid and degasification of the wastewater in a deaerator before reaching the VCE process.

The VCE evaporator system assumed for this option was previously described in Appendix C.1.3. At the design flow rate of 300 gpm, the case study system would generate 270 gpm of evaporator distillate and 29 gpm of brine. For this option, the evaporator brine would be mixed with amendments to form a solid, and then the solidified brine/ash material would be disposed of in a lined landfill.

Brine solidification is a highly site-specific process whereby the composition of the FGD wastewater brine and water treatment chemicals (antiscalants, defoamers, acid/bases) will impact the solidification amendments required to properly dispose of the final composite waste. Benchand pilot-scale testing would be required for any plant to determine the preferred mixture of amendment materials and to confirm whether the waste material can meet all the requirements for landfill disposal. These requirements may include passing the toxicity characteristic leaching procedure or "paint filter" test as well as meeting other property requirements necessary for longterm deposition in a landfill, such as hydraulic conductivity, compressive strength and other requirements.

For this case study, EPRI has assumed that the solidification process would generate a nonpumpable solid waste stream which would be trucked and disposed of in a landfill. The solid waste material is assumed to be composed of 18 weight percent of the evaporator brine, 77 weight percent of fly ash and 5 weight percent of quicklime. EPRI's research indicates that the suitable amount of brine in a non-pumpable mixture may be between 15 and 20 weight percent for plants burning eastern bituminous coal. Costs developed for this option assume 18 weight percent brine in the mixture (i.e., the mid-point of the suitable brine weight percentage range for bituminous coal sites). Table D-4 shows that the costs for residuals disposal are the highest O&M cost element for this option.

The suitable amount of brine in the solid waste mixture would be significantly lower for plants burning powder river basin (PRB) coal. Sites that burn PRB coal can typically achieve higher cycles of concentration in scrubber and evaporative systems which may lead to smaller brine volumes. However, for a given flowrate, the FGD brine from a PRB site will be higher in TDS. The higher TDS leads to a lower range of brine mass suitable in the solidified mixture, leading to more fly ash and quicklime amendments being required and therefore higher costs.

EPRI has been evaluating other processes for brine solidification [EPRI, 2017; EPRI, 2018; EPRI 2019], such as producing a pumpable mixture or “paste” that contains a greater weight percentage of brine in the mixture (between 30 and 40 percent for plants burning eastern bituminous coal) than can be used in a trucking waste option. Both the non-pumpable and pumpable options may be considered in an actual installation. However, EPRI has selected the non-pumpable basis for this costing since it is more commonplace in the United States and allows greater flexibility for waste placement in either an onsite or offsite landfill. The nonpumpable (truckable) approach is estimated to be $6M/year higher annualized cost compared to the pumpable option, assuming the pumpable brine/ash material is composed of 35 weight percent of the evaporator brine, 60 weight percent of fly ash and 5 weight percent of quicklime. Cost variances for capital and O&M costs for a pumpable approach are provided in Section D.1.2.2 and Section D.1.2.3.

EPRI used responses to EPA’s ELG Information Collection Request (ICR) for megawatts scrubbed and FGD wastewater design flow to estimate typical fly ash availability at a plant that generates 300 gpm of FGD wastewater. The estimated fly ash generation range was estimated to be between 119,000 to 336,000 tons per year, with an average of 198,000 tons per year per plant.

EPRI estimated that roughly 160,000 tons per year of fly ash would be required for brine solidification for this CP + VCE/BS case study. Therefore, EPRI has assumed there is sufficient fly ash available for this hypothetical case study plant.

Many sites currently sell their fly ash for profit. Therefore, sites using brine solidification may need to forfeit sale of some or all of their fly ash for use in the solidification process. EPRI assumed an average plant across the industry:

- Currently produces 198,000 tons per year of fly ash
- Sells 60 percent of their fly ash, or 119,000 tons per year
- Disposes of the remaining 40 percent of their fly ash, or 79,000 tons per year
- The case study plant would require 160,000 tons fly ash per year for evaporator brine solidification. All of the fly ash currently being disposed (79,000 tons per year) would be used for brine solidification. An additional 81,000 tons of fly ash per year would be diverted from current beneficial reuse sales for brine solidification. This results in a profit loss incurred as an additional annual cost.

- The remaining 38,000 tons per year of available fly ash would continue to be sold by the plant.
- Sites may need to make improvements to landfill operations (i.e. permit modifications, updated fill plan) and/or landfill leachate collection, management and treatment systems in order to dispose of the solidified brine/ash material. These are potential additional site specific costs that are not included in this case study. As shown in Appendix C, EPRI estimated landfill leachate costs to the industry for CS + VCE/CRX.

The key aspects of a CP + VCE/BS treatment system are:

- **Treatment objective** – Elimination of wastewater direct discharge by means of thermal treatment and evaporation of water. This results in a distillate stream and a concentrated wastewater (brine) with a reduced flow. Amendments are mixed with the concentrated wastewater stream resulting in a non-pumpable (truckable) material. This material, along with solids removed in the pretreatment (chemical precipitation) process, are disposed in a landfill. This case study assumes that the distillate stream will be recycled back into the plant for reuse. Certain plants may be permitted and choose to discharge their distillate. Site specific analysis of the challenges related to reuse and direct discharge of distillate would be required for all sites.
- **Key equipment** – Equalization tank, chemical reaction tanks, clarifiers, neutralization tank, evaporator feed tank, chemical feed systems, vapor-compression evaporator system, brine storage tank, distillate/reuse tank, pug mill, and filter presses.
- **Wastes** – The final residuals are calcium sulfate pretreatment solids and solidified brine/ash material, both requiring disposal in a lined landfill.

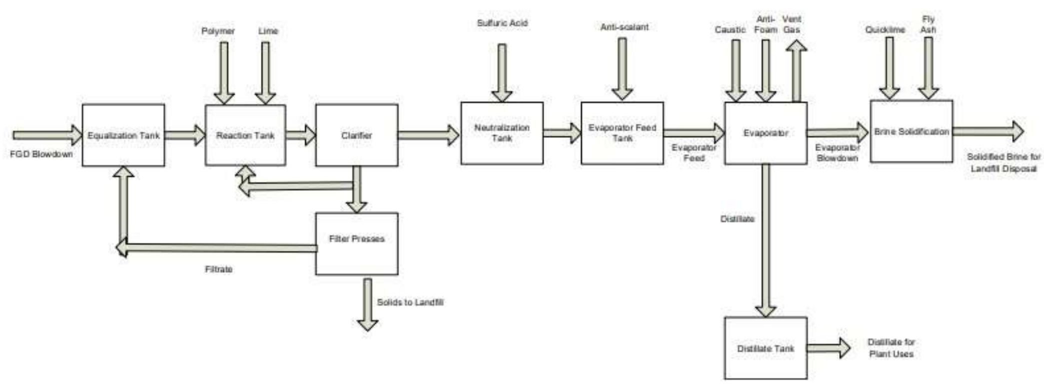

Figure D-1
Chemical precipitation with vapor compression evaporation and brine solidification system

D.1.2.1 Cost development methods

In this case study, EPRI has assumed a single plant's FGD wastewater design flow rate of 300 gpm.

FGD wastewater is pretreated through two identical trains at 60 percent capacity for all pretreatment equipment. The actual degree of redundancy that plants will choose will be based on site-specific considerations.

Using the reconciled FGD water quality (Table C-3), a major equipment vendor provided an installed cost quotation for a system consisting of two identical trains of seeded slurry brine concentrators each sized for 60 percent of the design flow rate and a single pug mill system for brine solidification. EPRI added the cost of a second pug mill, to provide redundancy.

The vendor estimated the cost for a "turnkey" system that included total installed costs within battery limits of the equipment package. Assumptions related to the scope of the turnkey system are the same as shown for Vendor B in Appendix C.

Upstream and downstream equipment from the evaporator system, including equalization equipment, chemical feed equipment, solids dewatering equipment, intermittent brine storage system, and distillate storage system were not part of the turnkey design. Therefore, EPRI costed these systems separately. In addition, this conceptual design assumes the need for a redundant pug mill system. EPRI estimated the cost for an additional pug mill system since only one pug mill system was quoted by the vendor.

D.1.2.2 Capital cost assumptions and estimate

The costs presented represent Class 4 estimates, generally defined as study- or feasibility-level estimates, for total installed costs (+50% to -30% accuracy). A definition of cost estimate classifications is presented in Appendix A.

Cost model factors and other major assumptions align with CS + VCE/CRX assumptions outlined in Section C.1.6. Specific assumptions for this option include:

- The power plant already has fly ash silos installed for its existing fly ash; therefore, no costs were added for fly ash silos.
- EPRI has included the cost of new quicklime silos that would be required for chemical supply as part of the brine solidification process.
- Engineering costs include an additional 1 percent of the total construction costs to account for the costs for bench- and pilot-scale brine solidification testing, which would be required for this option.
- Two 24-hour intermittent evaporator brine storage tanks and mixers were included, which would allow for intermittent brine storage when the pug mills are not operating.
- Costs for landfill operation improvements (i.e., permit modifications, updated fill plan) are potential plant costs that are not included in this case study.
- Cost for improvements to landfill leachate collection, management and treatment systems are potential additional costs that are not included in this case study cost estimate.

Table D-2
Summary of estimated CP + VCE/BS treatment capital costs, non-pumpable solid waste, in June 2018 dollars

Cost Element ($ thousand)	
Evaporator Vendor System Installation [a]	$22,757
Support equipment	
Equalization system	$1,326
Evaporator feed handling and storage equipment	$153
Chemical feed equipment	$200
Chemical precipitation equipment	$1,455
Chemical precipitation solids dewatering	$2,557
Brine handling and storage equipment, Spare pugmill	$1,126
Quicklime feed and quicklime silo	$1,099
Cold distillate handling and storage equipment	$346
Freight (4%) and taxes (0%)	$1,241
Subtotal – Purchased Support Equipment Cost as Delivered	**$8,593**
Subtotal – Vendor System Installation and Purchased Support Equipment Cost as Delivered	**$32,261**
Additional cost items [b]	
Pre-engineered building [d]	$7,071
Tie-in allowance [e]	$88
Site work [f]	$1,290
Piping [c]	$2,148
Mechanical / Heating, Ventilation, and Cooling [c]	$644
Instruments and Controls [c]	$1,289
Electrical	$7,097
Concrete [c]	$1,504
Miscellaneous metals, finishes [c]	$1,289
Subtotal – Direct Costs	**$54,681**
General contractor general conditions [b, c]	$3,877
Bonding and insurance [b]	$1,558
General contractor profit [b, c]	$4,419
Subtotal – Direct and Indirect Costs	**$64,535**
Miscellaneous unidentified cost [b]	$12,907
Subtotal – Estimated Construction Cost	**$77,442**

Table D-2 (continued)
Summary of estimated CP + VCE/BS treatment capital costs, non-pumpable solid waste, in June 2018 dollars

Cost Element ($ thousand)	
Engineering (design, testing, startup during construction, startup, and operator training) [b, g]	$16,263
Client administrative and overhead [b]	$5,421
Permitting	$57
Total Estimated Capital Cost ($ million)	**$99**
Total Estimated Capital Cost ($ million) +50%	**$149**
Total Estimated Capital Cost ($ million) –30%	**$69**

M = million
$ = U.S. dollars
[a] Vendor provided quotation for a turnkey process island (total installed cost) in December 2018. System consists of 2 x 60% evaporator system and single pug mill system.
[b] See Table C-4 for factors used to estimate these additional cost items.
[c] Included in vendor system installed cost, therefore this cost factor was applied to support equipment costs only
[d] Pre-engineered building was estimated at 22,500 square feet which includes two floors. Building was assumed to accommodate an office, motor control center (MCC), chemicals storage, dewatering equipment and evaporator system.
[e] Assumes wastewater tie-in piping of 1,000 linear feet installed above grade.
[f] Includes fencing, grading, roads, sidewalks, and similar items.
[g] Assumes 21 percent for engineering. An additional 1 percent of the total construction cost is added in this cost estimate to account for the costs of bench- and pilot- scale brine solidification testing.

Using a similar approach, EPRI estimated the capital costs for the case study site assuming a pumpable solid waste mixture (35 weight percent brine) would be generated. Using this basis, the capital costs for the system were estimated to be $98 million, roughly the same capital costs for a system generating a non-pumpable solid waste. Key differences for the pumpable case study costs were assumed to be: (1) additional pumps and one-mile pipeline to convey the waste to the landfill and (2) reduced size of the brine solidification equipment including fly ash pug mills and quicklime storage silo. Table D-3 provides an abbreviated table showing equipment costs that differ for this case study compared to the non-pumpable case study costs shown in Table D-2.

Table D-3
Estimated capital cost variances for CP + VCE/BS treatment, pumpable solid waste, in June 2018 dollars

Cost Element ($ thousand)	
Support equipment with cost that differ from Non-Pumpable option (see prior table)	
Brine handling and storage equipment, Spare pugmill	$1,096
Quicklime feed and quicklime silo	$557
Additional cost items not in the Non-Pumpable option (see prior table)	
Solid waste piping to landfill [a]	$377,000

M = million
$ = U.S. dollars
[a] Assumes one-mile buried pipeline to convey pumpable solid waste to landfill.

D.1.2.3 Operations and maintenance cost assumptions and estimate

Major assumptions align with CS + VCE/CRX assumptions outlined in Appendix C.1.7, with additional or different assumptions as follows:

- Pretreatment chemical dosages for this option were based on calcium sulfate precipitation pre-treatment using hydrated lime at pH 9.
- Labor is assumed to be the same as the CS + VCE/CRX option: a total of 10 full-time equivalent (FTE) operators at $49/hour, one supervisor at $76/hour, and one chemical engineer at $91/hour were assumed to staff the facility.
- As noted in Section D.1.2, EPRI is assuming that the case study plant currently disposes of 40 percent of their fly ash. EPRI estimated the disposal cost for the entire solidified brine waste (including fly ash) and then applied a cost deduction for the 40 percent of the fly ash that is already being disposed (baseline assumption) as to only include the incremental cost increase due to new wastewater treatment.
- EPRI has assumed that the average plant in the industry sells 60 percent of their fly ash (119,000 tons per year) and must forfeit selling 81,000 tons of fly ash per year for beneficial reuse as a result of implementing this technology option. The net revenue loss as a result of forfeited fly ash sales was assumed to be $10 per ton. Not all plants sell their fly ash and those that do may sell more or less than the tons assumed in this case study. Therefore, lost fly ash sales and the existing cost for fly ash onsite disposal are shown separately at the bottom of Table D-4 so that O&M costs may be estimated with and without these site specific costs.
- Residuals disposal is the highest O&M cost element and will vary greatly based on the plant's landfill location, transportation methods, current landfill capacity and other factors. EPRI has assumed $54/ton on a dry-weight basis (Appendix C). EPRI is showing these costs separately in Table D-4 due to the significance and variability of this site-specific cost element.
- EPRI has assumed that falling-film evaporator tube cleanings will occur twice per year.
- EPRI has assumed a plant capacity factor of 0.51, which is the industry average based on data from 2015 through 2017.

Table D-4
Summary of CP + VCE/BS treatment annual O&M costs, in June 2018 dollars

Cost Element ($ thousand per year)	
Chemicals [a]	
Antiscalant	$11
Antifoam	$12
Sulfuric acid (93%)	$35
Caustic (50%)	$1
Polymer	$34
Quicklime for solidification	$1,415
Hydrated lime for chemical precipitation	$60
Supplemental fly ash for solidification	$0

Table D-4 (continued)
Summary of CP + VCE/BS treatment annual O&M costs, in June 2018 dollars

Cost Element ($ thousand per year)	
Subtotal – Chemicals	**$1,567**
Electricity	$432
Steam	$0
Cooling water	$56
Evaporator tube cleanings	$535
Maintenance	$545
Labor	$1,372
Compliance monitoring	$151
Miscellaneous unidentified cost	$932
Total Estimated O&M Cost for Wastewater Treatment	**$5,590**
Lost fly ash sales	$806
Residuals, non-RCRA hazardous landfill disposal	$9,841
Existing cost for fly ash onsite disposal	-$4,257
Total Estimated O&M Cost with Fly Ash Sales and Disposal Costs	**$11,980**

M = million
O&M = operations and maintenance
RCRA = Resource Conservation and Recovery Act
$ = U.S. dollars
[a] Chemical costs are industry average and include an assumed national average freight. Chemical costs will vary depending on plant location and local chemical distributors

Using a similar approach, EPRI estimated the O&M costs for the pumpable solid waste mixture to be $6M per year, approximately half of the O&M cost estimated for a system generating a non-pumpable solid waste. Key differences for the pumpable case study costs were assumed to be: (1) reduced quicklime quantity needed for brine solidification, (2) no loss of fly ash sales (fly ash tons currently disposed is greater than fly ash tons required for solidification), and (3) reduced residuals quantities for disposal.

The same residuals disposal cost, $54/ton on a dry-weight basis, was assumed in developing the pumpable solid waste cost estimate. There is likely to be a different $/ton disposal cost for a paste system given that the transportation system is capitalized (i.e., piping and pumps) instead of hauled by trucking and the deposition in the landfill is passive and less labor/equipment intensive

Table D-5 provides an abbreviated table showing costs that differ for this case study from the non-pumpable case study costs shown in Table D-4.

Table D-5
Estimated O&M cost variances for CP + VCE/BS treatment, pumpable solid waste, in June 2018 dollars

Cost Element ($ thousand per year) that differ from non-pumpable option in prior table	
Chemicals [a]	
Quicklime for solidification	$728
Lost fly ash sales	$0
Residuals, non-RCRA hazardous landfill disposal	$4,441
Existing cost for fly ash onsite disposal	-$3,442

M = million
O&M = operations and maintenance
RCRA = Resource Conservation and Recovery Act
$ = U.S. dollars
[a] Chemical costs are industry average and include an assumed national average freight. Chemical costs will vary depending on plant location and local chemical distributors.

D.1.3 Treatment overview of chemical softening followed by seawater reverse osmosis and brine solidification (CS + SWRO/BS)

This evaluation considers a treatment option that includes full chemical softening (CS) followed by membrane separation and brine solidification (Figure D-2). Like the CP + VCE/BS option (section D.1.2), this option assumes solidification (i.e., encapsulation) and landfill disposal of concentrated FGD wastewater. For this reason, this conceptual design will refer to the final treatment process as "brine solidification" as a means of clarifying that the process and underlying assumptions are generally the same as the "brine solidification" process previously described in section D.1.2

- Key design requirements for this membrane case study, compared to the conceptual designs assumed in Appendix C and D.1.2, include:
- This option requires chemical softening (CS) pretreatment upstream of the membrane system to remove calcium, magnesium, and silica that would otherwise cause significant scaling issues on the surface of the membranes. The softening approach is the same lime and soda ash softening system as previously described for CS + VCE/CRX treatment in Appendix C.
- The brine solidification process and approach are assumed to generally be the same as the CP + VCE/BS solidification system (section D.1.2), however the membrane process would produce a greater volume of concentrated wastewater that must be solidified and then disposed.

This treatment option includes full chemical softening pre-treatment followed by neutralization to pH 7 using sulfuric acid. The neutralized, softened, settled stream would be treated through either a microfiltration (MF) or ultrafiltration (UF) system for removal of total suspended solids (TSS). The objective of the MF (or UF) system is to remove suspended solids in the softening clarifier overflow (typically around 30 mg/L TSS) and thereby protect the reverse osmosis membranes downstream. The MF system was assumed to achieve 95 percent recovery and the remaining 5 percent of filtrate would be used for MF backwashing. The MF backwash system would include a backwash collection tank followed by a backwash settling tank for settling of the backwashed solids. The supernatant from the settling tank would be returned to the equalization tank. Settled backwash solids could be pumped to the final waste tank for solidification and disposal, if necessary.

The MF filtrate would be treated with an antiscalant and then fed to the RO system. For this conceptual design, EPRI selected a three-stage seawater reverse osmosis (SWRO) system to maximize the permeate recovery and reduce concentrate flow. Interstage booster pumps would be used between the first and second stages to promote a flux balance. EPRI performed membrane projection and antiscalant modeling for this system which indicated that the maximum achievable permeate recovery would be 81 percent, which is limited by the recovery achievable based on the FGD wastewater's salinity and the allowable SWRO membrane design pressure. If the permeate recovery was limited by the membrane scaling tendency (for example, if the softening system was less effective or the feed water quality was more challenging) then the maximum achievable recovery would likely be less. At the design flow rate of 300 gpm and the design recovery of 81 percent, the system would generate 243 gpm of permeate and 57 gpm of RO concentrate.

This case study was developed to maximize RO recovery assuming that the RO permeate would be used for onsite reuse. If reused, it would need to be used in a process that does not discharge to a permitted outfall. Designing a membrane system for discharging permeate to a permitted outfall, which must therefore meet the ELG limits for this option, would likely require designing for a reduced RO recovery leading to higher RO concentrate flows, increased solid waste generation, and therefore higher costs. The RO concentrate would be pumped to the final waste tank and then solidified for landfill disposal using a pug mill system.

The brine solidification process and approach are assumed to generally be the same as the CP+ VCE/BS solidification system (Section D.1.2). For example, the process would generate a nonpumpable solid waste stream which would be trucked and disposed of in a landfill. The solid waste material is assumed to be composed of 18 weight percent of the evaporator brine, 77 weight percent of fly ash and 5 weight percent of quicklime.

EPRI estimated that roughly 309,000 tons per year of fly ash would be required for brine solidification for this case study. This exceeds the estimated 198,000 tons of fly ash generation per year for an average plant that generates 300 gpm of FGD wastewater (Section D.1.2). Therefore, EPRI has assumed there would not be sufficient fly ash available at this case study plant and supplemental fly ash would need to be purchased from another site. This conceptual design includes 111,000 tons per year of additional purchased fly ash, transportation, and new fly ash silos to store the additional fly ash required.

As with CP + VCE/BS, some sites may need to make improvements to landfill operation (i.e., permit modifications, updated fill plan) and/or landfill leachate collection, management and treatment systems in order to dispose of the solidified brine/ash material. These are potential costs that are not included in this case study. As shown in Appendix C, EPRI estimated landfill leachate costs to the industry for CS + VCE/CRX.

The RO and MF membrane systems would require a clean-in-place (CIP) chemical cleaning system. The CIP system would be used for periodic maintenance and recovery cleanings of the membranes to keep the surfaces of the membrane clean and to prolong the life of the membranes. The RO system would also require a flush system. The flush system would be used to flush a RO skid immediately after it is taken offline.

The key aspects of this CS + SWRO/BS treatment system are:

- **Treatment objective** – Elimination of wastewater direct discharge by means of membrane separation of water and solids. This results in a permeate stream and a concentrated wastewater (concentrate) with a reduced flow. Amendments are mixed with the concentrated wastewater stream resulting in a non-pumpable (truckable) material. Softening pretreatment and antiscalants are required to prevent membrane scaling. The solids from the solidified brine and softening solids are disposed in a landfill. EPRI assumed that the permeate will need to be recycled back into the plant. Reuse options will be challenging for some plants.
- **Key equipment** – Equalization tank, softening reaction tanks, softening clarifiers, membrane feed tanks, chemical feed systems, microfiltration system, reverse osmosis filtration system, RO concentrate storage tank, pug mill, clean-in-place system, backwash tanks and pumps, flush tank, permeate storage tank and filter presses.
- **Wastes** – The final residuals are softener solids and solidified concentrate solids, both requiring disposal in a lined landfill.

D.1.3.1 Cost development methods

In this case study, EPRI has assumed a single plant's FGD wastewater flow rate of 300 gpm. FGD wastewater is pretreated through two identical trains at 60 percent capacity for all equipment. The actual degree of redundancy that plants will choose will be based on site-specific considerations.

The membrane systems (MF/UF and RO) were designed for N+1 treatment train redundancy, meaning that the design system flow capacity is satisfied by "N" trains plus one redundant (standby) train. Therefore, in this 300 gpm design case study, EPRI has assumed a membrane system design consisting of four trains each sized for 100 gpm (400 gpm total feed capacity).

The equipment costs for the membrane system were provided by a major equipment vendor (Vendor C). Using the softened water chemistry for the reconciled FGD water, the vendor provided equipment costs for four ultrafiltration system skids, the backwash pump skid, four 3-stage seawater reverse osmosis system skids, the CIP system, the CIP chemical dosing system, an air supply system (for instrument air and air scour operations), master control panels, and startup services.

The vendor quote for this case study included only the equipment skid packages and excluded all other direct cost items, including interconnect piping between skids and tanks. For this reason, the membrane vendor costs were not "turnkey," which is unlike the quotations provided by the thermal equipment vendors (Appendix C and section D.1.2). Therefore, for this case study, all the system-wide cost factors used in the EPRI estimates (see Table C-4) were applied to the membrane vendor's quoted equipment costs.

Upstream and downstream equipment from the membrane system, including equalization equipment, chemical feed equipment, softening process equipment, solids dewatering equipment, MF feed tank, MF filtrate tank, backwash system, flush tank system, temporary RO concentrate storage system, the permeate storage system, and the dual pug mill system were not part of the vendor's costs. Therefore, EPRI estimated the costs for this additional equipment.

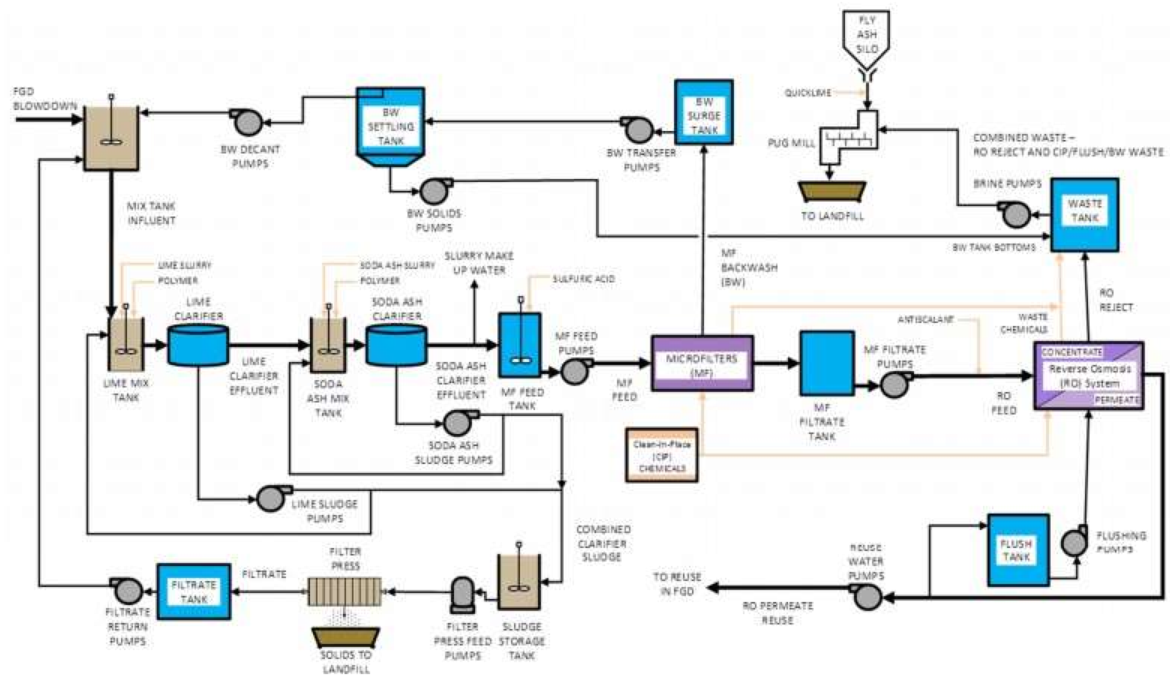

Figure D-2
Chemical softening with reverse osmosis and brine solidification system

D.1.3.2 Capital cost assumptions and estimate

The costs presented represents Class 4 estimates, generally defined as study- or feasibility-level estimates, for total installed costs (+50% to -30% accuracy). A definition of cost estimate classifications is presented in Appendix A.

Cost model factors and other major assumptions align with assumptions outlined in section C.1.6 and section D.1.2.2. Specific assumptions for this option include:

- Cost estimate includes the cost of two pug mill systems.
- Two 24-hour intermittent RO concentrate storage tanks and mixers which would allow for intermittent concentrate storage when the pug mills are not operating.

The capital cost estimate for the CS+ SWRO/BS case study is shown in Table D-6.

Table D-6
Summary of estimated CS + RO/BS treatment capital costs, in June 2018 dollars

Cost Element ($ thousand)	
Equipment	
Equalization system	$1,380
Lime Softening	$1,780
Soda Ash Softening	$1,600
Membrane Filtration [a]	$1,210
Reverse Osmosis [a]	$1,880
Brine handling and storage, Pug mills	$2,850
Solids Dewatering	$5,930
Backwash Pumping and Storage	$240
Permeate Reuse Pumping and Storage	$180
Quicklime feed and silo storage, Fly ash silo storage	$4,156
Mercury Analyzer and Recycle Pumps	$105
Freight (4%) and taxes (0%)	$763
Subtotal – Purchased Equipment Cost as Delivered	**$22,074**
Additional cost items [b]	
Pre-engineered building [c]	$8,375
Tie-in allowance [d]	$88
Site work [e]	$763
Piping	$4,771
Mechanical / Heating, Ventilation, and Cooling	$1,431

Table D-6 (continued)
Summary of estimated CS + RO/BS treatment capital costs, in June 2018 dollars

Cost Element ($ thousand)	
Additional cost items [b]	
Instruments and Controls	$2,863
Electrical	$4,199
Concrete	$3,340
Miscellaneous metals, finishes	$2,863
Subtotal – Direct Costs	**$50,767**
General contractor general conditions [b]	$6,346
Bonding and insurance [b]	$1,447
General contractor profit [b]	$7,234
Subtotal – Direct and Indirect Costs	**$65,794**
Miscellaneous unidentified cost [b]	$13,159
Subtotal – Estimated Construction Cost	**$78,953**
Engineering (design, testing, startup during construction, startup, and operator training) [b, f]	$16,580
Client administrative and overhead [b]	$5,527
Permitting	$45
Total Estimated Capital Cost ($ million)	**$102**
Total Estimated Capital Cost ($ million) +50%	**$153**
Total Estimated Capital Cost ($ million) –30%	**$71**

M = million
$ = U.S. dollars
[a] Vendor provided costs for a UF/RO/CIP equipment package in March 2019.
[b] See Table C-4 for factors used to estimate these additional cost items.
[c] Pre-engineered building was estimated at 33,500 square feet which includes two floors. Building was assumed to accommodate an office, motor control center (MCC), chemicals storage, dewatering equipment and membrane equipment. The building area required for the UF/RO equipment skids was developed based on vendor input.
[d] Assumes wastewater tie-in piping of 1,000 linear feet installed above grade.
[e] Includes fencing, grading, roads, sidewalks, and similar items.
[f] Assumes 21 percent for engineering. The additional 1 percent of total construction cost is to account for the costs of bench- and pilot- scale brine solidification testing.

D.1.3.3 Operations and maintenance cost assumptions and estimate

RO treatment will result in approximately twice as much concentrated wastewater for disposal compared to VCE in comparably sized systems. Thus, the greater volume of liquid for disposal requires proportionately more quicklime and fly ash, and the disposal costs for this RO option are greater than those shown for CP + VCE/BS in Section D.1.2.3.

Major assumptions for chemical softening align with CS + VCE/CRX assumptions outlined in Appendix C. This case study includes additional O&M assumptions as follows:

- Labor: a total of 14 full-time equivalent (FTE) operators at $49/hour, one supervisor at $76/hour, and one chemical engineer at $91/hour were assumed to staff the facility. Additional operators were included in this case study due to the greater amount of encapsulated waste generated and the assumed need to operate the treatment system 7 days per week.
- The CIP system would use the following chemicals:
    - Sodium Hypochlorite ($1.08/lb.)
    - Citric Acid ($1.58/lb.)
    - Sodium hydroxide ($0.61/lb.)
    - Sodium tripolyphosphate (STPP) ($1.96/lb.)
    - Sodium ethylenediaminetetraacetic acid (Na-EDTA) (0.88/lb.)
- Membrane cleaning frequency has not been clearly demonstrated and is unknown. This case study assumed membrane cleaning would be required weekly for UF maintenance cleans, monthly for UF recovery cleans and quarterly for RO recovery cleans. More frequent cleaning may be needed at some plants thereby increasing operating costs and causing more of an operability challenge.
- Element replacement frequency has also not been clearly demonstrated and is unknown. This case study assumed that element replacements would occur every three months for cartridge filters (roughing filters to UF system), every five years for UF membranes and every three years for reverse osmosis membranes. The costs of these element replacements were averaged over the replacement period to calculate an annual replacement cost.
- EPRI has assumed a plant capacity factor of 0.51, which is the industry average based on data from 2015 through 2017.
- EPRI has assumed that the average site across the industry (119,000 tons of fly ash per year) would not generate sufficient fly ash to solidify the RO reject wastewater on an annual basis. EPRI estimates that approximately 111,000 tons per year of additional fly ash would need to be purchased. A market price of $35 per ton fly ash and $11.51 per ton for transportation was assumed, for a total purchased fly ash cost of $46.51 per ton.

The O&M cost estimate for the CS+ SWRO/BS case study is shown in Table D-7.

Table D-7
Summary of CS + SWRO/BS treatment annual O&M costs, in June 2018 dollars

Cost Element ($ thousand per year)	
Chemicals [a]	
Hydrated lime for softening	$639
Soda Ash for softening	$841
Polymer	$222
Sulfuric acid (93%)	$68
Antiscalant	$4
Sodium Hypochlorite	<$1

Table D-7 (continued)
Summary of CS + SWRO/BS treatment annual O&M costs, in June 2018 dollars

Cost Element ($ thousand per year)	
Chemicals [a]	
Caustic	<$1
Citric acid	$1
STPP	$1
Na-EDTA	$1
CIP Neutralization chemicals	$2
Quicklime for solidification	$2,738
Supplemental fly ash for solidification	$5,156
Subtotal – Chemicals	**$9,670**
Electricity	$147
Filtration element replacement	$37
Maintenance	$573
Labor	$1,780
Compliance monitoring	$151
Miscellaneous unidentified cost	$2,472
Total Estimated O&M Cost for Wastewater Treatment	**$14,830**
Lost fly ash sales	$1,188
Residuals, non-hazardous landfill disposal	$18,730
Existing cost for fly ash onsite disposal	-$4,257
Total Estimated O&M Cost with Fly Ash Sales and Residuals	**$30,490**

M = million
O&M = operations and maintenance
$ = U.S. dollars
[a] Chemical costs are industry average and include an assumed national average freight. Chemical costs will vary depending on plant location and local chemical distributors.

D.1.4 Treatment overview of chemical precipitation followed by advanced membrane filtration and brine solidification (CS + AMF/BS)

This evaluation considers a treatment option that includes chemical precipitation (CP) followed by advanced membrane filtration and brine solidification (AMF/BS) (Figure D-3). Like the CS + SWRO/BS option (section D.1.3), this option assumes solidification (i.e., encapsulation) and landfill disposal of concentrated FGD wastewater.

Key design requirements for the CP + AMF/BS option, compared to the conceptual design of CS + SWRO/BS assumed in section D.1.3, include:

- Only chemical precipitation (CP) for solids removal was assumed for pretreatment. Full chemical softening (CS), using hydrated lime and soda ash, is not assumed for this case study.

- An advanced membrane filtration (AMF) system is assumed for the membrane system. The term AMF is being used by EPRI to define one of the membrane systems considered by EPA that is "designed specifically for high TDS and TSS wastestreams" and is "designed to eliminate fouling and scaling associated with industrial wastewater" [EPA, 2019]. EPA evaluated several membrane technologies since the 2015 ELG including BKT FMX membrane technology [ERG, 2019a, Appendix B], KLeenWater technology [ERG, 2019a, Appendix I], New Logic membrane technology [ERG, 2019a, Appendix K], Oasys forward osmosis technology [ERG, 2019a, Appendix L], Purestream membrane technology [ERG, 2019a, Appendix M] and Saltworks technology [ERG, 2019a, Appendix N]. For this conceptual design analysis, EPRI has assumed an equipment configuration which includes the New Logic Vibratory Shear Enhanced Process (VSEP) filtration followed by a reverse osmosis (RO) membrane system.
- The AMF membrane process is assumed to have an overall recovery of 70%, which is lower than the recovery assumed for the CS+SWRO/BS design (Section D.1.3).

The pretreatment for the assumed FGD wastewater in this case study is the same as the CP + VCE/BS option (D.1.2). It consists of hydrated lime addition to pH 9 to encourage calcium sulfate precipitation and to reduce the solids concentration fed to the AMF process. The objective of this pre-treatment is to precipitate and remove solids. Pretreatment for this option does not include targeted removal of dissolved hardness parameters (i.e., calcium and magnesium). Chemical pretreatment is followed by pH neutralization using sulfuric acid prior to the VSEP and RO process.

The advanced membrane system includes the New Logic VSEP filtration system followed by a spiral-wound RO for polishing. Pumps and a break tank are included between the VSEP and RO systems. The reject from the RO system is recycled to the head of the VSEP membrane process rather than being directly wasted. The pilot dataset provided by New Logic VSEP [ERG, 2019a, Appendix K, Table 1], shows a range of 55 to 83.2 percent overall recovery achieved in six different FGD wastewater pilots. The average overall recovery for these pilots was 72 percent. For this conceptual design evaluation, EPRI has assumed an overall system recovery of 70 percent. At the design flow rate of 300 gpm through the AMF system, the system would generate 210 gpm of RO permeate and 90 gpm of reject from the VSEP system for solidification and landfill disposal.

This case study assumes that the permeate would be used for onsite reuse. If reused, it would need to be used in a process that does not discharge to a permitted outfall. Designing a membrane system for discharging permeate to a permitted outfall, which must therefore meet the ELG limits for this option, may require designing for a reduced RO recovery leading to higher RO concentrate flows, increased solid waste generation, and therefore higher costs.

The brine solidification process and approach are assumed to be similar to the CP+ VCE/BS and CS+SWRO/BS solidification systems (Section D.1.2 and section D.1.3). The process would generate a non-pumpable solid waste stream which would be trucked and disposed of in a landfill. The solid waste material is assumed to be composed of 18 weight percent of the evaporator brine, 77 weight percent of fly ash and 5 weight percent of quicklime.

EPRI estimated that roughly 454,000 tons per year of fly ash would be required for brine solidification for this case study. This exceeds the estimated 198,000 tons of fly ash generation per year for an average plant that generates 300 gpm of FGD wastewater (Section D.1.2). Therefore, EPRI has assumed there would not be sufficient fly ash available at this case study plant and supplemental fly ash would need to be purchased from another site. This conceptual design includes 256,000 tons per year of additional purchased fly ash, transportation, and new fly ash silos to store the additional fly ash required.

As with CP + VCE/BS and CS + SWRO/BS options, some sites may need to make improvements to landfill operation (i.e., permit modifications, updated fill plan) and/or landfill leachate collection, management and treatment systems in order to dispose of the solidified brine/ash material. These are potential costs that are not included in this case study. As shown in Appendix C, EPRI estimated landfill leachate costs to the industry for CS + VCE/CRX.

The VSEP and RO filtration systems would require a clean-in-place (CIP) chemical cleaning system. The CIP system would be used for periodic maintenance cleanings of the membranes to keep the surfaces of the membrane clean and to prolong the life of the membranes. The RO system would also require a flush system. The flush system would be used to flush a RO skid immediately after it is taken offline. The key aspects of this CP + AMF/BS treatment system are:

- **Treatment objective** – Elimination of wastewater direct discharge by means of membrane separation of water and solids. This results in a RO permeate stream and a concentrated wastewater reject. Amendments are mixed with the reject wastewater stream resulting in a non-pumpable (truckable) material. Chemical pretreatment and clean in place are required to attain reliable membrane operations. The solids from the solidified reject and pre-treatment solids are disposed in a landfill. EPRI assumed that the permeate will need to be recycled back into the plant. Reuse options will be challenging for some plants.
- **Key equipment** – Equalization tank, reaction tanks, pretreatment clarifiers, feed tanks, chemical feed systems, ARO system (VSEP + RO), reject storage tank, pug mill, clean-in place system, flush tank, and filter presses.
- **Wastes** – The final residuals are pretreatment solids and solidified reject solids, both requiring disposal in a lined landfill.

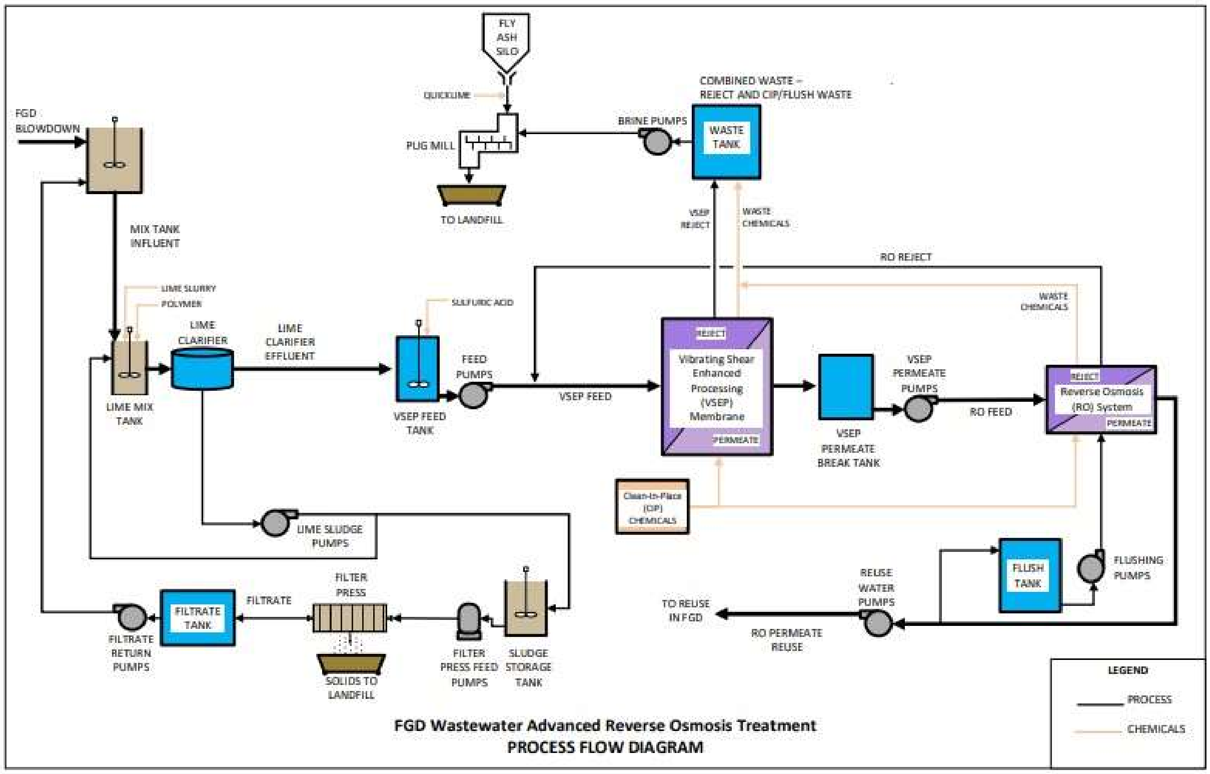

Figure D-3
Chemical precipitation with advanced membrane filtration and brine solidification system

D.1.4.1 Cost development methods

In this case study, EPRI has assumed a single plant's FGD wastewater flow rate of 300 gpm. FGD wastewater is pretreated through two identical trains at 60 percent capacity for all equipment. The actual degree of redundancy that plants will choose will be based on site-specific considerations.

The membrane system (VSEP and RO) was designed for 120 percent redundancy. The VSEP and RO system equipment costs were estimated based on two equipment quotations provided by New Logic [ERG, 2019b] and other cost estimates available to EPRI. All of the system-wide cost factors used in the EPRI estimates (see Table C-4) were applied to the VSEP and RO equipment costs to develop a total capital cost.

Upstream and downstream equipment from the AFM system, including equalization equipment, chemical feed equipment, pretreatment equipment, solids dewatering equipment, feed tanks and pumps, flush tank system, reject storage system, the permeate storage system, and the dual pug mill system were not part of the vendor's costs. Therefore, EPRI estimated the costs for this additional equipment.

D.1.4.2 Capital cost assumptions and estimate

The costs presented represents Class 4 estimates, generally defined as study- or feasibility-level estimates, for total installed costs (+50% to -30% accuracy). A definition of cost estimate classifications is presented in Appendix A.

Cost model factors and other major assumptions align with assumptions outlined in Appendix C and Appendix D. Specific assumptions for this option include:

- Chemical precipitation (CP) equipment (matching assumptions from D.1.2) was considered. This includes a single stage of chemical addition and clarification, rather than a two-stage system as considered for CS.
- Overall recovery from the membrane system is assumed to be 70 percent. This results in larger reject tanks, greater storage volume for fly ash (two silos), and more capacity for solidification (two larger pugmills) compared to the CS + SWRO/BS system.
- Additional tankage was included for CIP neutralization.

The capital cost estimate for the CS+ AMF/BS case study is shown in Table D-8.

Table D-8
Summary of estimated CP + AMF/BS treatment capital costs, non-pumpable solid waste, in June 2018 dollars

Cost Element ($ thousand)	
VSEP/RO System [a]	$10,732
Support Equipment	
Equalization system	$1,326
Evaporator feed handling and storage equipment	$319
Chemical feed equipment	$82

Table D-8 (continued)
Summary of estimated CP + AMF/BS treatment capital costs, non-pumpable solid waste, in June 2018 dollars

Cost Element ($ thousand)	
Support Equipment	
Chemical precipitation equipment	$1,290
Chemical precipitation solids dewatering	$2,557
Brine handling and storage equipment, spare pugmill	$3,073
Quicklime feed and quicklime silo	$6,813
Cold distillate handling and storage equipment	$306
Freight (4%) and taxes (0%)	$1,060
Subtotal – Purchased Support Equipment Cost as Delivered	**$16,397**
Subtotal – Vendor System Installation and Purchased Support Equipment Cost as Delivered	**$27,558**
Additional cost items [b]	
Pre-engineered building [c]	$8,171
Tie-in allowance [d]	$88
Site work [e]	$1,060
Piping	$6,625
Mechanical / Heating, Ventilation, and Cooling	$1,987
Instruments and Controls	$3,975
Electrical	$5,830
Concrete [c]	$4,637
Miscellaneous metals, finishes	$3,975
Subtotal – Direct Costs	**$63,906**
General contractor general conditions [b]	$7,988
Bonding and insurance [b]	$1,821
General contractor profit [b]	$9,107
Subtotal – Direct and Indirect Costs	**$82,822**
Miscellaneous unidentified cost [b]	$16,564
Subtotal – Estimated Construction Cost	**$99,386**
Engineering (design, testing, startup during construction, startup, and operator training) [b, f]	$20,871
Client administrative and overhead [b]	$6,957
Permitting	$57

Table D-8 (continued)
Summary of estimated CP + AMF/BS treatment capital costs, non-pumpable solid waste, in June 2018 dollars

Cost Element ($ thousand)	
Total Estimated Capital Cost ($ million)	$127
Total Estimated Capital Cost ($ million) +50%	$191
Total Estimated Capital Cost ($ million) –30%	$89

M = million
$ = U.S. dollars
[a] The VSEP and RO system equipment costs were estimated based on two equipment quotations provided by New Logic [ERG, 2019b] and other cost estimates available to EPRI.
[b] See Table C-4 for factors used to estimate these additional cost items.
[c] Pre-engineered building was estimated at 26,000 square feet which includes two floors. Building was assumed to accommodate an office, motor control center (MCC), chemicals storage, dewatering equipment and evaporator system.
[d] Assumes wastewater tie-in piping of 1,000 linear feet installed above grade.
[e] Includes fencing, grading, roads, sidewalks, and similar items.
[f] Assumes 21 percent for engineering. The additional 1 percent of total construction cost is added in this cost estimate to account for the costs of bench- and pilot- scale brine solidification testing.

D.1.4.3 Operations and maintenance cost assumptions and estimate

AMF treatment is estimated to recover 70% of water overall. Thus, the 30% of volume of liquid for disposal requires proportionately more quicklime and fly ash for disposal compared to the RO option in section D.1.3.

Major assumptions for chemical precipitation and reject disposal align with CP + VCE/CRX assumptions outlined in Appendix C. This case study includes additional O&M assumptions as follows:

- CIP chemicals, antiscalant, and other maintenance chemicals are collectively captured under “Membrane cleaning chemicals”.
- The VSEP filtration system and RO membranes are assumed to be replaced every 5 years. The cost is reflected in O&M cost as 20% of the VSEP/RO package per year.
- EPRI has assumed that the average site across the industry (119,000 tons of fly ash per year) would not generate sufficient fly ash to solidify the RO reject wastewater on an annual basis. EPRI estimates that approximately 256,000 tons per year of additional fly ash would need to be purchased. A market price of $35 per ton fly ash and $11.51 per ton for transportation was assumed, for a total purchased fly ash cost of $46.51 per ton.

The annual O&M cost estimate for the CS+ AMF/BS case study is shown in Table D-9

Table D-9
Summary of CP + AMF/BS treatment annual O&M costs, in June 2018 dollars

Cost Element ($ thousand per year)	
Chemicals [a]	
Sulfuric acid (93%)	$18
Polymer	$34
Quicklime for solidification	$4,022
Hydrated lime for chemical precipitation	$60
Supplemental fly ash for solidification	$11,913
Membrane cleaning chemicals	$67
Subtotal – Chemicals	**$16,113**
Electricity	$156
Filtration element replacement	$2,146
Maintenance	$764
Labor	$1,781
Compliance monitoring	$151
Miscellaneous unidentified cost	$4,222
Total Estimated O&M Cost for Wastewater Treatment	**$25,333**
Lost fly ash sales	$1,188
Residuals, non-hazardous landfill disposal	$26,288
Existing cost for fly ash onsite disposal	-$4,257
Total Estimated O&M Cost with Fly Ash Sales and Residuals	**$48,552**

O&M = operations and maintenance
M = million
$ = U.S. dollars
[a] Chemical costs are industry average and include an assumed national average freight. Chemical costs will vary depending on plant location and local chemical distributors.

D.1.5 Summary comparison of voluntary incentive program (VIP) case studies

A comparative summary of the capital, O&M and total annualized cost estimates for the different voluntary incentive program (VIP) design options, as described in Appendices C and D, are presented in Table D-10. Each case study cost estimate presented in Table D-10 assumes a 300 gpm FGD wastewater design flow basis but varies based on the assumed equipment redundancy and technology option selected.

The costs for FGD wastewater solidification will vary considerably based on the quantity and quality of the FGD wastewater purge flow and the amount of fly ash generated onsite. Sites with higher FGD purge flows would likely incur disproportionately higher costs, either due to the need to concentrate the FGD wastewater to match fly ash availability onsite (potentially leading to more than one wastewater concentration stage) and/or would be required to purchase additional amendment materials (quicklime, fly ash) to solidify a larger FGD brine volume. For D-26 this reason, brine solidification technology options are likely much more favorable for sites with lower FGD flowrates.

Table D-10
Summary of screening-level (+50%/-30%) capital, O&M, and total annualized cost estimates for five case studies

Cost Element	CS + VCE/CRX [a] 2 x 100%	CS + VCE/CRX [b] 2 x 60%	CP + VCE/BS [c] 2 x 60%	CS + SWRO/BS [d] 2 x 60%	CP+ AMF/BS [e] 2 x 60%
Capital Costs ($M)	171	143	99	102	127
Annualized Capital Costs ($M per year) [f]	16	14	9.3	9.6	12
O&M Costs ($M per year) [g]	8.5	7.8	12	30	49
Wastewater Treatment Costs ($M per year) [h]	7.5	6.8	5.6	15	25
Disposal Costs ($M per year)	1.0	1.0	5.6	14	22
Lost Fly Ash Sales ($M per year)	0	0	0.8	1.2	1.2
Total Annualized Costs ($M per year) [i]	25	21	21	40	61
Vendor Basis [j]	B	B	B	C	D

O&M = operations and maintenance
M = million
$ = U.S. dollars
[a] 2 x 100% chemical softening systems, 2 x 100% vapor compression evaporator systems and 2 x 100% crystallizer systems (Appendix C)
[b] 2 x 100% chemical softening systems, 2 x 60% vapor compression evaporator systems and 1 x 100% crystallizer system (Appendix C)
[c] 2 x 60% chemical precipitation systems, 2 x 60% vapor compression evaporator systems and 2 x 100% pugmill systems (Section D.1.2)
[d] 2 x 60% chemical softening, N + 1 ultrafiltration, N+1 SWRO membrane and 2 x 100% pugmill systems (Section D.1.3)
[e] 2x60% chemical precipitation systems, 120% VSEP + spiral wound RO polishing system and 2 x 100% pugmill systems (Section D.1.4).
[f] Annualized cost based on a 20-year equipment life and 7% interest rate.
[g] Total O&M cost including wastewater treatment costs, disposal costs and lost fly ash sales.
[h] Wastewater treatment O&M costs including electricity, chemicals, labor, equipment maintenance, compliance monitoring, steam, cooling water, and miscellaneous unidentified cost
[i] Total annualized cost included annualized capital cost and total O&M cost.
[j] Refer to Appendix C for description of Vendor B costs and Section D.1.3 for description of Vendor C costs. The New Logic VSEP technology is the basis for Vendor D.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 8

Comment Excerpt:

Flue Gas Desulfurization Wastewater
FirstEnergy appreciates USEPA's review and update of the Flue Gas Desulfurization Wastewater ("FGDW") sections by updating information; however, FirstEnergy has certain concerns with the FGDW sections of the ELG Rule as they are currently proposed. FirstEnergy

supports the technical and economic considerations highlighted in the EPRI and UWAG comments.

FGDW Cost Information
FirstEnergy has specific concerns after reviewing the costs EPA provided in the Proposed Rule's docket. See EPA-HQ-OW-2009-0819-8220. FirstEnergy supplied EPA with cost information upon request, based on site specific factors and engineering analysis, for our facilities. The information was provided to EPA on, or around, February 28, 2018 and is in the record. See EPA-HQ-OW-2009-0819-7310, Attachment 35. FirstEnergy encourages EPA to review this information and update the Proposed ELG Rule's cost information accordingly, as the EPA costs differ significantly from the FirstEnergy supplied costs. While EPA has used cost curves, based on vendor estimates and academic cost adders, to develop a national cost estimate at each facility, FirstEnergy strongly believes that where site specific analysis and engineering data is available, EPA should use such data to develop cost curves. In fact, EPRI's cost curves used this approach and had significantly higher costs than EPA is anticipating in the Proposed ELG Rule. Each site has different cost adders based on many different scenarios, such as available space and comingled systems; therefore, specific engineering cost analysis should be considered and used, where available.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 22

Comment Excerpt:

(iii) EPA's cost analysis methodology supporting the rule has significant flaws, likely overestimating costs for capital and operating expenses of FGD wastewater treatment systems;

Commenter Name: Tim Pickett
Commenter Affiliation: Frontier Water Systems
Document Control Number: EPA-HQ-OW-2009-0819-8295-A1
Comment Excerpt Number: 3

Comment Excerpt:

As a water treatment system vendor, I support finalization of this rule. Frontier Water Systems is a US company, founded with the mission of advancing FGD wastewater treatment technology, requiring a supportive regulatory framework. With the regulations in motion over the last decade, wastewater from coal fired steam electric facilities has not universally been treated to modern discharge standards required by most other industries. During this time the technical challenges for treating these water streams have largely been overcome, and regulatory certainty will result in the deployment of water treatment throughout the industry.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 2

Comment Excerpt:

Specifically, EPA should:

…

- Move forward with both the technology basis and compliance dates proposed for FGD wastewater, but consider adjusting those limitations, as EPA's proposed limits do not reflect the wide variety of unit operations and variable circumstances that impact unit performance;

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 8

Comment Excerpt:

Second, EPA should finalize both the technology basis and compliance dates proposed for FGD wastewater—but the Agency should consider whether to adjust those limits to accommodate unit variability and other factors. The Agency's technology basis and compliance dates are well supported, achievable and provide units with the necessary time for compliance, but the numeric limitations EPA derived do not reflect the wide variety of unit operations and variable circumstances that impact unit performance since EPA relied on pilot studies when setting those limits. As such, the Agency should consider whether it should adjust those limits to explicitly account for this variability.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 11

Comment Excerpt:

Southern Company agrees that chemical precipitation followed by a LRTR biological treatment system, including ultrafiltration, achieves the greatest overall performance (i.e., selenium, mercury, and nitrate-nitrite removal) relative to other technologies considered. Even so, the proposed technology choice may pose certain technical challenges that could be avoided and that EPA should address in a final rulemaking. For instance, EPA should re-evaluate the data to revise numeric limits for selenium and mercury and should reconsider whether a nitrate-nitrite limit is necessary at all. EPA should also reconsider the costs of the BAT technology. EPA's estimated costs delineated in the proposed rule for chemical precipitation and LRTR biological treatment are considerably underestimated. It is important for EPA to evaluate the true costs of the proposed BAT, especially when considering the subcategorization for units planning to retire and for low utilization boilers.

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 3

Comment Excerpt:

1. Prior Analysis of High Recycle Rate FGD Systems

The Agency began collecting detailed information on the differences among FGD systems several years prior to the 2015 rule, conducting in-depth site visits as early as 2008. [7] EPA compiled its findings from this initial investigative work in a 2009 "Final Detailed Study Report" or "Final Study."[8] The Final Study identified a variety of technologies to treat or reduce FGD purge water, including settling ponds, chemical precipitation, biological treatment, constructed wetlands, evaporation, and, importantly, "variations of complete recycle" wet scrubber systems. [9]

Of the plants opting for complete recycle, most employed some method for solidifying or fixing constituents of FGD blowdown and transferring the solidified product to landfills. [10] While some complete recycle systems operated "forced oxidation" scrubbers and some "inhibited oxidation" scrubbers, EPA determined that "inhibited oxidation systems are more likely than forced oxidation systems to be operated in a manner that recycles the .. . [purge] stream from the solids separation process back to the scrubber, and thus are less likely to discharge from a scrubber purge stream."[11] EPA also concluded that "the type of oxidation (i.e., forced oxidation, inhibited oxidation, natural oxidation) in the FGD system has the potential to affect the form of the pollutants present in the FGD wastewater."[12]

Despite the label of "complete recycle" systems, the details of EPA's early investigation established that these systems in fact often required some minimal, periodic discharge. Typically, this discharge was necessary to maintain the system's water balance. One facility, for instance, relied primarily on reclamation tanks to provide surge volume. [13] But that facility still required "a[n] FGD emergency overflow pond[,]" and, although it did not " typically use the pond" and typically recycled the overflow[14] even when it did, it nonetheless connected this overflow pond to the bottom ash pond to allow for discharges as needed. [15] Another facility "accumulated rainfall in their ponds which treat the recycle water" and "manage[d] the additional water volume by discharging from the FGD ponds."[16] Given the need for some minimal, sporadic discharge, Cleco refers to these systems as "high recycle rate" rather than "complete recycle."

As EPA proceeded to a rulemaking, however, it appears to have attended less to the nuances of high recycle rate systems. In the Technical Development Document for the 2015 rule (the "2015 TDD"), EPA again noted that the "sorbent and type of oxidation the FGD system used ... affects the species of pollutants present in the FGD wastewater." [17] These differences arose in part because "inhibited oxidation systems use other types of sorbents" than forced oxidation. [18] Roughly half of the high recycle rate systems identified by EPA in 2015 operated inhibited oxidation systems. [19]

Nonetheless, the 2015 TDD pointedly chose not to include inhibited oxidation FGD systems in its on-site sampling program- precisely because inhibited oxidation produced less purge water and was typically unaccompanied by chemical precipitation or biological treatment.[20] The 2015 TDD instead merely assumed that "wastewater pollutants present in these systems are similar to those generated by [forced oxidation] systems[,]" its earlier statements on the potential differences in pollutants notwithstanding. [21] Ultimately, the FGD wastewater characterization in the 2015 TDD "represent[ed] data from plants operating limestone forced oxidation systems" alone.[22] The 2015 TDD also appears to have based its FGD flow rate analysis on a similarly limited universe of facilities.[23]

The 2015 rule would later determine that high recycle rate systems were not nationally available and thus could not supply the technological basis for generally applicable BAT standards.[24] The cunent proposed rule reaches a similar conclusion. [25] The technical basis for the proposed rule appears to continue to rely on the 2015 TDD's data set, supplementing it only with new information on bromides.[26]

[7] *See, e.g.;* EPA, Notes from Site Visit at Ohio Power Company's Gavin Plant (2008) (Docket No. EPA-HQ-OW2009-0819-0694) [hereinafter "Gavin Site Visit Notes"].
[8] See generally EPA, Steam Electric Power Generating Point Source Category: Final Detailed Study Report (2009) (Docket No. EPA-HQ-OW-2008-0819-0004) [hereinafter "Final Detailed Study Report"].
[9] *See generally* Final Detailed Study Report § 4.4; *id.* at 4-36.
[10] *See, e.g., id.* at 4-36 to 4-37.
[11] *Id.* at 4-11.
[12] *Id.* at 4-18.
13 See Gavin Site Visit Notes at 4.
[14] "Overflow" is used here in its ordinary sense, not in the specialized sense unique to the FGD solids-separation process.
[15] *Id.* at 5.
[16] Final Detailed Study Repmt at 4-13.
[17] EPA, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category 6-3 (2015) (Docket No. EPA-HQ-OW-2009-0819-6432) [hereinafter "2015 Technical Development Document"].
[18] *Id.* at 6-3.

[19] *Id.* at 7-19.
[20] *Id.* at 3-9, 3-9 n.11.
[21] *Id.* at 3-9 n.11.
[22] *Id.* at 6-3.
[23] *See id.* at 6-1 to 6-2.
[24] See 2015 Rule, 80 Fed. Reg. at 67,860, 67,850 n.21.
[25] See Proposed Rule, 84 Fed. Reg. at 64,631, 64,631 n.17.
[26] See Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category 6-5 (2019) (Docket No. EPA-HQ-OW-2009-0819-7106) [hereinafter "Supplemental Technical Development Document"].

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 5

Comment Excerpt:

Dolet Hills operates a high recycle rate FGD system, and this system incorporates three surge ponds. These ponds are small (less than 5 acres each) but necessary to allow the scrubber to drain during significant maintenance or other outages in which the scrubber cannot operate. When these outages coincide with heavy precipitation events (e.g., Hurricane Harvey), the surge ponds must discharge to prevent overflow elsewhere. These discharges are authorized under the terms of an LPDES permit, and Cleco estimates that this system has been forced to discharge ' only an average of 8.4 days per year between 2013 and 2019. Much like the facilities described in the Final Study, and like the maintenance purges proposed for BATW, the Dolet Hills system experiences only periodic, contingency-driven discharges necessary to allow its recycling system to operate efficiently at all other times.

Applying the average capital cost from the 2019 TDD, each day of discharge from Dolet Hills would correspond to roughly $226,000 in capital outlays alone. This per-day ratio appears to be over twice even that for the TV A Cumberland facility, which EPA identified as sufficient grounds for a separate subcategory for high FGD flows.[33] But unlike the Cumberland facility, the capital costs for Dolet Hills would likely still be unreasonable even if chemical precipitation alone were required.[34] As the Agency correctly noted in proposing its high flows subcategory, it makes no sense either for Cleco to absorb such costs or to pass them on to consumers.[35]

There is no realistic benefit propo1tionate to these costs. Removing marginal amounts of constituents from a modest amount of effluent, already removed of most solids and highly diluted by precipitation, for a few days each year does not justify several million dollars. The infrequency of the flows simply caps the total possible pollutants avoided.[36]

In any event, the general benefit of treating these sorts of discharges has never been rigorously established. The 2015 TDD chose to exclude many of the facilities that might require small, periodic discharges, namely, those with inhibited oxidation systems. It is not clear that the

Agency can rationally assume, as it eventually did in the 2015 TDD, that purge water from inhibited oxidation is identical to that from forced oxidation. It cannot therefore assume that chemical precipitation and biological treatment for purges from inhibited oxidation will accrue the same benefits. Given the large costs of compliance, any corresponding benefits are presumptively inadequate.

[33] See Proposed Rule, 84 Fed. Reg. at 64,638 ("EPA's cost estimates are even higher than TVA's (a $256 million . dollar capital cost ....)."). When calculating this ratio, Cleco has assumed that the Cumberland facility discharged for at least 360 days over seven years and divided the total capital costs by the total number of days discharging (2,520 total days).
[34] For that reason, even the low utilization boiler subcategory does not adequately address high recycle rate FGD systems.
[35] Proposed Rule, 84 Fed. Reg. at 64,6438.
[36] Cleco estimates that the average per,day discharge for these events at 1.023 MGD. This would equate to a constant flow of about 2,803 gallons per day over an entire year. It is clearly not cost-justified, or technically feasible, to impose chemical precipitation and biological treatment on that amount of daily flow.

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 7

Comment Excerpt:

3. Appropriate Limitations for High Recycle Rate FGD Systems

The application of the statutory factors makes it clear that a subcategory for high recycle rate FGD systems should not require chemical precipitation and biological treatment, even that with low residence time. Instead, the better approach is to do what EPA has done for high recycle rate bottom ash transpmt systems: provide covered facilities with the ability to discharge under discrete, justifiable conditions. [38] Otherwise, discharges from the system would be prohibited. Here, in fact, the conditions authorizing discharge might be even narrower. Where the proposed rule allows BATW purges based on water chemistry, maintenance, and water balance, the examples of discharges from otherwise "complete recycle" systems identified above suggest that only maintenance or precipitation-driven water balance conditions are necessary for FGD purges.[39] The permitting authority could determine an appropriate limit for the magnitude of these discharges based on historical data of heavy precipitation events compared to the facility's existing surge capacity.

The Agency might even go further than the control measures proposed for the BATW volumetric purges. First, many facilities with high recycle rate FGD systems have incorporated dedicated impoundments or similar containment structures to help remove solids, manage water balance, and increase recycling. [40] In Cleco's case, these impoundments are necessary to drain the system during maintenance events and to catch and return FGD solids filtrate during no1mal operation. EPA might justifiably require such facilities to prepare a BMP plan to reduce precipitation-related inflows to these structures (and thus reduce discharges driven by water imbalance); the Agency has already proposed a similar control measure for bottom ash transport water generated by low utilization boilers. [41] Many facilities might already have such plans or practices to meet other regulatory requirements.

Second, EPA might justifiably impose limitations for TSS and O&G on authorized discharges. Because these discharges have often moved through a containment structure to settle out solids, they employ technology similar to the surface impoundments used to develop TSS and O&G limits for a variety of other subcategories.[42] Again, this would be similar to the proposal for bottom ash transport water from low utilization boilers.

[38] See id at 64,674-75 (to be codified at 40 C.F.R. § 423.13(k)(2)(i)).
[39] See Final. Detailed Study Report at 4-13 (noting discharges from the Cane Run facility "where they have accumulated rainfall in their ponds which treat the recycle water[,]" thereby requiring "discharg[e] from the FGD ponds").
[40] See, e.g., Final Detailed Study Report at 4-11, 4-13; see also Gavin Site Visit Notes at 4.
[41] See Proposed Rule, 84 Fed. Reg. at 64,675 (to be codified at 40 C.F.R. § 423.13(k)(2)(iii)(A)-(k)(3)).
[42] See, e.g., 40 C.F.R. § 423.12(b)(11) (BPT for FGD wastewater); see also id § 423.13(g)(2) (applying BPT limits as BAT for generating units with nameplate capacity,at or under 50 megawatts).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 68

Comment Excerpt:

a. <u>EPA Overestimates Compliance Costs</u>.

EPA justifies the High Flow Subcategory based only on compliance costs, but the agency significantly overestimates those costs. Compliance costs correlate to FGD wastewater flow rate,[237] which EPA estimates as exceeding four million gallons per day (mgd) for the Cumberland Plant.[238]

First EPA's cost calculations incorrectly assume the Cumberland Plant constantly operates at full capacity, generating 2,470 MW, but Cumberland's average generation over the last three years was 1,244 MW.[239] About half the generation means about half the FGD wastewater flow rates and about half the costs.

It is irrational to base costs on peak output. Cumberland rarely reaches 2,470 MW in generation. Those peaks have become increasingly rare, a trend likely to continue.[240] TVA could meet peak demand through other facilities in its diverse generation portfolio. TVA could add equalization capacity, temporarily storing excess FGD wastewater in rare instances when the Cumberland Plant must approach 2,470 MW. These alternative responses to peak demand would lower costs by ensuring that the Cumberland Plant could consistently recirculate FGD wastewater without risk of corrosion.

Second, EPA ignores TVA's reasonable alternatives to decrease FGD flow and thereby decrease costs. EPA states that chlorine concentrations bar wastewater recirculation at the Cumberland

Plant, leading to high flows and high costs. But TVA has an obvious and simple solution to lower chlorine concentrations in its FGD wastewater: use more Powder River Basin coal, which has about twenty times less chlorine than TVA's current blend.[241] Lower chlorine levels would allow the Cumberland Plant to recirculate more wastewater without risk of corrosion. By recirculating more wastewater, Cumberland would decrease its FGD purge flow and compliance costs.

Although EPA asserts in the preamble that its rationale for the High Flow Subcategory "reflects the reasonably predictable flow associated with actual and expected FGD operations,"[242] the agency did not consider the ramifications of the Cumberland Plant's actual (and declining) capacity factors in its cost analysis.[243] EPA's cost analysis is unsupported by the record, which shows that Cumberland Plant's costs are much lower than EPA estimates and that TVA has reasonable alternatives to lower those costs.

[237] See TDD, Section 5.2.1.
[238] EPA does not expressly find Cumberland exceeds 4 mgd in the preamble, but it cites Cumberland in establishing this category for facilities exceeding 4 mgd. EPA seems to rely on memoranda from the Environmental Research Group, which estimate Cumberland's FGD wastewater flows as exceeding 4 mgd. See, e.g, Sara Bossenbroek and Danielle Stewart, Environmental Research Group, "Flue Gas Desulfurizatioon Flow Methodology for Compliance Costs and Pollutant Loadings – DCN SE07091," Docket ID No. EPA-HQ-2009-0819-8200 (July 8, 2019)
[239] Dr. Ranajit Sahu, High FGD Flow Subcategory, at 10, Jan. 15, 2020 ("Sahu Report") (Attachment 70).
[240] See id. at 8–9.
[241] See id. at 6–7.
[242] 84 Fed. Reg. 64,638.
[243] Sahu Report, Attachment 70, at 9.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 142

Comment Excerpt:

a. EPA Overestimates Compliance Costs.

EPA justifies the High Flow Subcategory based only on compliance costs, but the agency significantly overestimates those costs. Compliance costs correlate to FGD wastewater flow rate,[540] which EPA estimates as exceeding four million gallons per day (mgd) for the Cumberland Plant.[541]

First, EPA's cost calculations incorrectly assume the Cumberland Plant constantly operates at full capacity, generating 2,470 MW, but Cumberland's average generation over the last three years was 1,244 MW.[542] About half the generation means about half the FGD wastewater flow rates and about half the costs.

It is irrational to base costs on peak output. Cumberland rarely reaches 2,470 MW in generation. Those peaks have become increasingly rare, a trend likely to continue.[543] TVA could meet peak demand through other facilities in its diverse generation portfolio. TVA could add equalization capacity, temporarily storing excess FGD wastewater in rare instances when the Cumberland Plant must approach 2,470 MW. These alternative responses to peak demand would lower costs by ensuring that the Cumberland Plant could consistently recirculate FGD wastewater without risk of corrosion.

Second, EPA ignores TVA's reasonable alternatives to decrease FGD flow and thereby decrease costs. EPA states that chlorine concentrations bar wastewater recirculation at the Cumberland Plant, leading to high flows and high costs. But TVA has an obvious and simple solution to lower chlorine concentrations in its FGD wastewater: use more Powder River Basin coal, which has about twenty times less chlorine than TVA's current blend.[544] Lower chlorine levels would allow the Cumberland Plant to recirculate more wastewater without risk of corrosion. By recirculating more wastewater, Cumberland would decrease its FGD purge flow and compliance costs.

Although EPA asserts in the preamble that its rationale for the High Flow Subcategory "reflects the reasonably predictable flow associated with actual and expected FGD operations,"[545] the agency did not consider the ramifications of the Cumberland Plant's actual (and declining) capacity factors in its cost analysis.[546] EPA's cost analysis is unsupported by the record, which shows that Cumberland Plant's costs are much lower than EPA estimates and that TVA has reasonable alternatives to lower those costs.

[540] See Proposed TDD, Section 5.2.1.
[541] EPA does not expressly find Cumberland exceeds 4 mgd in the preamble, but it cites Cumberland in establishing this category for facilities exceeding 4 mgd. EPA seems to rely on memoranda from the Environmental Research Group (ERG), which estimate Cumberland's FGD wastewater flows as exceeding 4 mgd. See, e.g, ERG, Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings – DCN SE07091, Docket ID No. EPA-HQ-2009-0819-8200 (July 8, 2019).
[542] Dr. Ranajit (Ron) Sahu, Technical Comments on EPA's Proposed Rule to Revise the Best Available Technology (BAT) Effluent Limitations Guidelines (ELGs) for Flue Gas Desulfurization (FGD) Wastewater and Bottom Ash Transport Water (BATW), at 48 ("Sahu Expert Report") (attached).
[543] See id. at 46-47.
[544] See id. at 44.
[545] 84 Fed. Reg. at 64,638.
[546] Sahu Expert Report at 47-48.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 20

Comment Excerpt:

(i) given the overwhelming evidence of the advanced state of FGD treatment technologies, EPA should have recognized that BAT for FGD wastewater is now clearly a treatment system that can achieve zero liquid discharge (ZLD). While this can be achieved in a number of ways, the use of spray dryer absorbers[52] or membranes – both mature technologies) are clear means of achieving ZLD for FGD wastewater[53];

52 See TDD at 4-6 for a description of spray dryer technology. I disagree with EPA that retrofitting such spray dryers in existing plants is any more difficult than retrofitting even more complex equipment such as wet FGDs themselves, at existing plants – which has been done numerous times in the last several decades at many U.S. coalfired power plants.
53 I also recognize that ZLD can be obviously achieved by thermal technologies other than SDA – such as by simply vaporizing the water and/or crystallizing the solids. See TDD at 4-6. It is my opinion, however, that such technologies are more cost-effective when applied to low volume wastes such as the rejects from membrane technologies as opposed to being the primary means of achieving ZLD (i.e., treating the entire FGD purge volume).

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 24

Comment Excerpt:

2.2 Characterization of the Current Coal-Fired Wet FGD Fleet

According to EPA, "[o]f the 550 coal-fired generating units at 284 coal-fired power plants in the updated profile, 270 generating units at 119 plants are serviced by a wet FGD system."[55] More importantly, as EPA notes,

Since the 2015 rule, steam electric power plants have conducted on-site testing and/or installed additional technologies to treat FGD wastewater. These technologies include, but are not limited to, low residence time reduction (LRTR) biological treatment, high residence time reduction (HRTR) biological treatment, advanced membrane filtration, and thermal evaporative systems. The EPA has identified that approximately ten percent of steam electric power plants with wet scrubbers have technologies in place able to meet the proposed BAT effluent limitations for FGD wastewater, including LRTR, HRTR, and thermal evaporation systems. As described in Section VII of the preamble, a further forty percent of all steam electric power plants with wet scrubbers use FGD wastewater management approaches that eliminate the discharge of FGD wastewater altogether. [56] (emphasis added)

The second of the points highlighted in the excerpt above – i.e., that 40% of plants with wet FGDs are currently managing FGD wastewater in a manner that eliminates the discharge of such waters altogether – cannot be more strongly emphasized. In fact, just on this basis alone, and consistent with the definition of BAT, EPA should have arrived at the conclusion that BAT for FGD wastewater is ZLD. As I will show below, the docket contains numerous technology options that plants can use, individually and in combination, to achieve ZLD for FGD wastewater.

55 TDD at 3-5.
56 Id. at 3-7.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 34

Comment Excerpt:

Conclusion. Based on this information from the docket materials, it is clear that membrane-based FGD wastewater treatment technologies have been technically feasible for some time and that they have been demonstrated at all scales and are capable of not only meeting the existing ELG requirements but can also meet a ZLD discharge. Given their availability now, there is no basis for EPA to conclude that they could not be used at the present time.

In any case, whether using SDA or using membranes and additional thermal technologies for evaporating the brines or using solidification techniques to deal with the brine, it is clear that there are numerous options to achieve ZLD for FGD wastewaters. Coupled with the fact noted earlier that 40% of wet FGD systems currently are able to manage their wastewater with no discharge, it is clear that BAT for FGD wastewater should be ZLD.

12 FGD Wastewater – Data

No comment excerpts were received on this topic.

13 FGD Wastewater – Halogens

Commenter Name: Kelly D. Good, Ph.D., P.E.
Commenter Affiliation: Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8299-A1
Comment Excerpt Number: 2

Comment Excerpt:

Wet FGD discharges can contribute significantly to bromide concentrations in downstream drinking water sources, and our work has found that this issue is not isolated to a single geographic location. While our method to estimate bromide loads from wet FGD discharges is adequate for a general assessment of the issue and for providing initial information about which power plants could potentially contribute bromide to downstream drinking water sources, it is important to note that it relies on historic coal consumption and coal quality data, which do not necessarily reflect current or future conditions. The best way to assess bromide loads from power plants remains the use of flow-weighted bromide concentration measurements for the flue gas desulfurization wastewater prior to mixing with other waste streams. This type of monitoring is particularly important due to the uncertainty in bromide loading caused by bromide addition, e.g., for mercury control or tax credit purposes.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 67

Comment Excerpt:

E —APPENDIX: BROMIDE

E.1 Errors in Calculation of Dry Coal Consumption and Bromide Mass in Coal

EPRI identified three errors in the methods used by EPA to calculate coal consumption for use in the bromide mass loadings calculations. The first relates to the equation used to convert from wet coal tonnage to dry coal tonnage. The second relates to the plant-wide moisture EPA used to calculate dry coal tonnage. The third relates to the procedure used to calculate weighted coal bromide concentration for plants that burned multiple coal ranks.

E.1.1 An incorrect equation is used to calculate dry coal consumption

EPA obtained wet coal tonnage for each EGU from U.S. Energy Information Administration (EIA) coal purchase records and converted the quantities to dry coal using the average moisture fraction for the county of coal origin, obtained from the USGS COALQUAL database [ERG, 2019a]. The equation that EPA used to convert wet coal consumption (Cwet) to dry coal consumption (Cdry) is shown below.

$$Cdry\left(\frac{tons}{yr}\right) = Cwet\left(\frac{tons}{yr}\right) \times \left(\frac{1}{1 - moisture\ content}\right)$$

This equation contains an error. The term (1-moisture content) should be in the numerator, not the denominator. Since the term (1-moisture content) is by definition less than 1, placing this term in the denominator results in a dry coal consumption rate larger than the wet coal consumption rate, which is not physically possible. The dry coal consumption should have been calculated as follows:

$$Correct\ Cdry\left(\frac{tons}{yr}\right) = Cwet\left(\frac{tons}{yr}\right) \times (1 - moisture\ content)$$

EPRI calculated the correct dry coal consumption for each coal type at each unit at each plant listed in EPA's bromide mass balance spreadsheet (DCN SE07260A01, EPA, 2019), and then determined the total dry coal consumption at each plant (Correct Total Cdry) by summing the total dry coal usage. The error associated with EPA's coal moisture conversion error was calculated as follows:

$$Error = \left(\frac{EPA\ Total\ Cdry}{Correct\ Total\ Cdry} - 1\right) x\ 100\%$$

$$Error = \left(\frac{EPA\ Total\ Cdry}{Correct\ Total\ Cdry} - 1\right) x\ 100\%$$

Table E-1 presents the range and mean of the errors produced by use of the incorrect equation. This table does not include plants firing multiple coal ranks because the EPA did not provide the moistures for each coal burned in the units, which are needed for the calculation.

Table E-1
Error in Dry Coal Tonnage on a Plant Basis

Coal Type	EPA Plant Count	Average Error	Minimum Error	Maximum Error
Bituminous	54	9%	4%	18%
Subbituminous	7	83%	55%	89%
Lignite	2	146%	127%	164%

Data source: EPA, 2019
Plant Count = number of plants firing only the coal type indicated; if a plant fired multiple coal ranks, the error could not be determined from information provided by EPA.

E.1.2 Weighted coal bromide for plants that burned multiple coals should be calculated with dry coal tonnage

The EPA calculated the Cdry value on a plant basis. For each unit within the plant, the as received (i.e., wet) coal consumption rates were tabulated by coal type. The coal consumption rates for all units were summed to obtain a plant coal consumption, Cwet. A "plant-specific average moisture" was applied to the unit's Cwet value as per EPA's Equation 1 to determine the Cdry value [ERG, 2019].

EPA calculated the amount of bromide in combusted coal using Equation 2 [ERG, 2019].

$$Br\ in\ coal\ \left(\frac{lb}{yr}\right) = Cdry \times \frac{2{,}000\ lb}{ton} \times \frac{Br\ (ppm, dry)}{10^6}$$

$$Br\ in\ coal\ \left(\frac{lb}{yr}\right) = Cdry \times \frac{2{,}000\ lb}{ton} \times \frac{Br\ (ppm, dry)}{10^6}$$

The EPA calculated the weighted average bromide mass in coal for each unit by weighting Cdry by the wet coal consumption for each coal type. This weighting factor is incorrect, as the bromide concentrations are on a dry basis, and thus must be weighted with the dry coal consumption. The EPA did not provide the information needed to accurately quantify the error associated with the incorrect weighting of the coal moisture.

E.2 EPA overestimated pre-combustion and post-combustion bromide addition

E.2.1 EPA overestimated pre-combustion bromide addition rates

EPA obtained bromide addition rates for plants burning refined coal or adding bromide to coal from values reported by EPRI [2015]. The bromide addition rates used [ERG, 2019] were:

- Bituminous coal: 298 ppm, dry
- Subbituminous coal: 97 ppm, dry.
- Lignite: 97 ppm, dry (EPA assumed same rate as subbituminous coal)

The 2015 report is one of a series of EPRI member surveys on balance-of-plant effects of bromide addition [EPRI, 2014; EPRI, 2015; EPRI, 2016; EPRI, 2017]. The survey responses indicated that, after 2014, most of the power companies participating in the surveys concluded that high bromide addition rates were problematic due to air heater corrosion, as well as unnecessary to meet the flue gas mercury emission standard. In response, refined coal producers obtained Section 45 certifications with lower amounts of bromide added to the coal in subsequent years.

EPRI reviewed bromide addition rates provided by owners of 108 coal-fired units that participated in the surveys from 2014 through 2017. The respondents included plants that used refined coal or added bromide for mercury control as part of a MATS compliance strategy. In the most recent survey [EPRI, 2017], respondents were asked if they had reduced their bromide addition rate over time. Of 63 EGUs whose owners participated in that survey, 35 units (56%) had decreased the halogen addition rate since commencing use of the technology [EPRI, 2017]. Many of the originally surveyed plants have since been retired. As of December 31, 2018, survey respondents with wet FGDs operated a total of 21 power plants with 42 EGUs.

Figure E-1 illustrates the trend in bromide addition over time as cumulative distribution plots of bromide usage rates for each year of the EPRI surveys. To represent the full spectrum of bromide usage across the current coal-fired power plant fleet, Figure E-1 includes data for all plants with wet FGDs that were still operating as of December 31, 2018, including plants that did not discharge to surface water and seven units that reported having ceased bromide addition over the course of the surveys (zero addition rate). The median bromide addition rate in 2017 among all EGUs participating in the surveys was 30 ppm, compared to a median value of 110 ppm in 2015, the year referenced by ERG [2019].

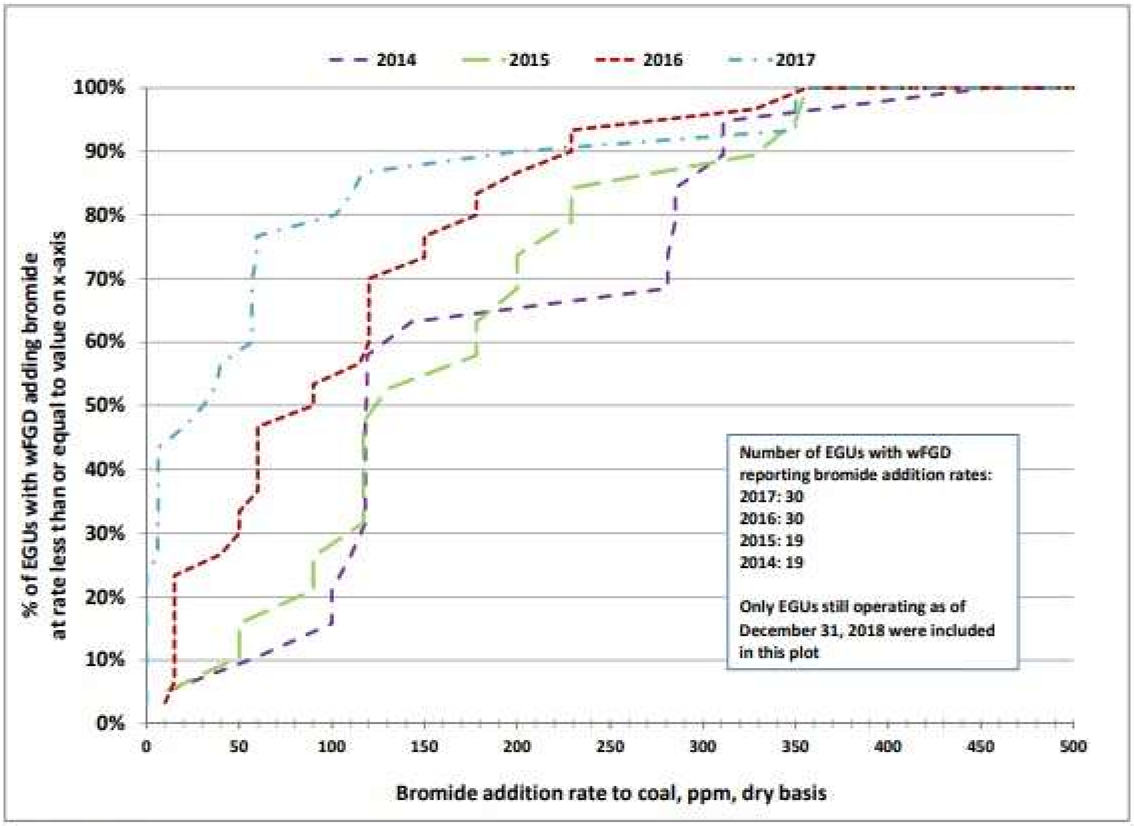

Figure E-1
Cumulative distribution plot of bromide addition rates for all units in EPRI surveys with wet FGDs

Figure E-2 shows the cumulative distribution plots of <u>non-zero</u> bromide addition rates from both the 2017 survey and the most recent response in any year of the surveys. The seven units that stopped adding bromide to the coal were excluded from this plot. The median non-zero bromide addition rate in 2017 was approximately 60 ppm. Eighty-three percent (29 units) of the 35 units surveyed reported bromide addition rates of 120 ppm or less. The remaining six units added bromide at rates of 200 ppm (one unit), 230 ppm (two units at one plant), and 350 ppm (three units at one plant); these are all zero liquid discharge plants.

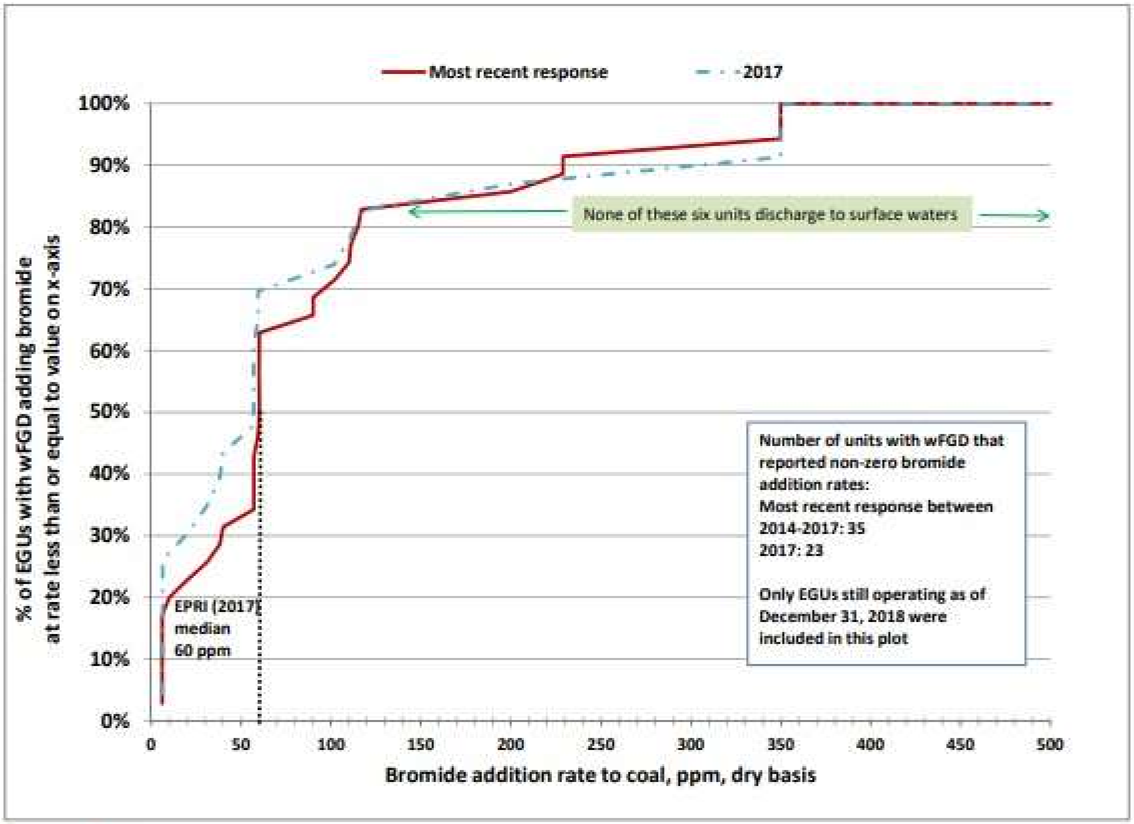

Figure E-2
Cumulative distribution plot of survey respondents that reported adding bromide to the coal in their most recent survey response

Using the most recent response from each of the surveyed plants over the 2014 through 2018 survey period, EPRI analyzed bromide addition rate by coal type, as shown in Figure E-3. Seven units that stopped adding bromide to the coal were excluded from this plot. The median addition rates for each coal type were significantly lower than the values reported by EPA.

- Bituminous coal: The median addition rate using the most recently reported survey data was 110 ppm. The 298-ppm addition rate assumed by EPA for bituminous coals is at the high end of rates reported for bituminous-fired units; 80% of units added bromide at concentrations less than this rate. The bituminous units with the five highest addition rates did not discharge to surface water.
- Subbituminous coal: The median addition rate using the most recently reported survey data was 10 ppm. The 97-ppm addition rate assumed by EPA for subbituminous coals is nearly ten times the median rate reported in the most recent EPRI survey for subbituminous coals; 90% of subbituminous units added bromide at concentrations less than this rate. The subbituminous units with the two highest addition rates did not discharge to surface water.
- Lignite: Only one lignite-fired unit participated in the EPRI surveys; its addition rate of 60 ppm is less than the assumption of 97 ppm used by EPA.

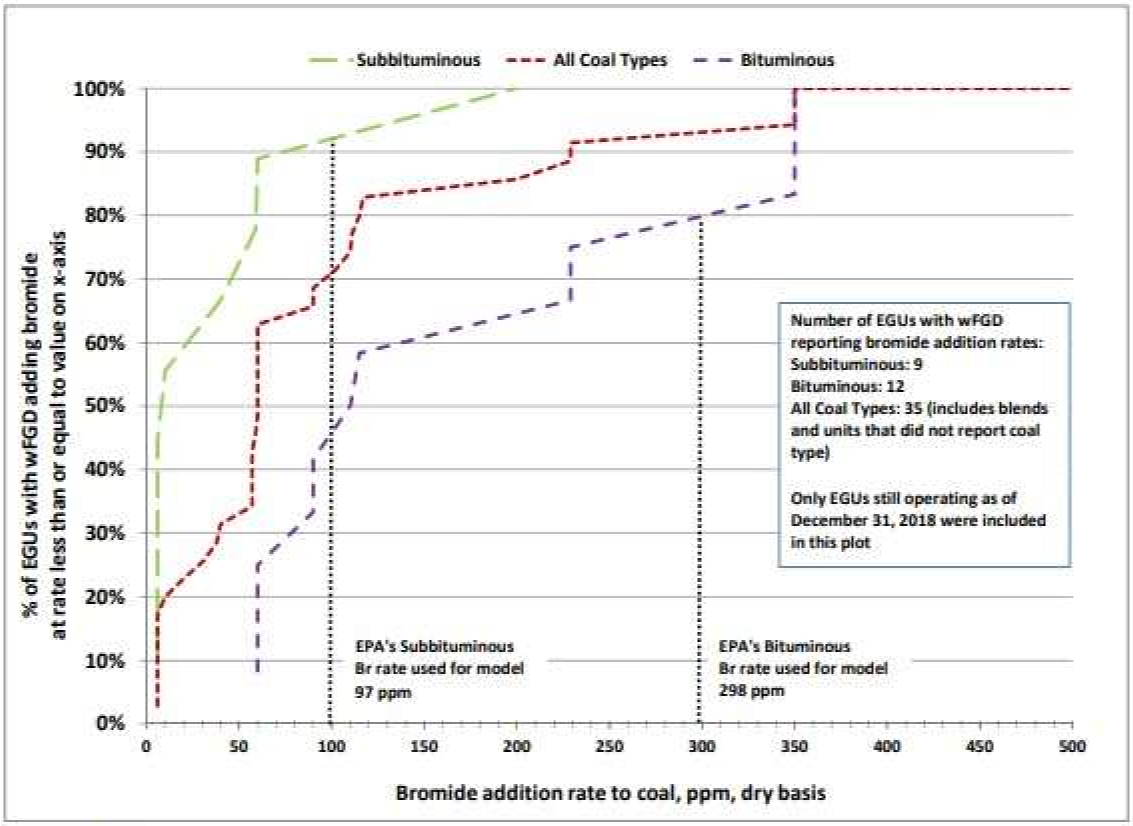

Figure E-3
Cumulative distribution plot of non-zero bromide addition rates for all units in EPRI surveys, by coal type

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 50

Comment Excerpt:

7.1.1 **EPA appears to have overestimated mass loadings from FGD wastewater.**

To estimate bromide loadings to surface water from discharge of FGD wastewater, EPA followed a methodology developed by Good and Van Briesen [2016; 2017; 2019]. EPRI's detailed review of these articles [EPRI, 2019] determined that the equation used by Good and Van Briesen to convert wet coal tonnage to dry coal tonnage is incorrect. A moisture correction term that should be in the numerator of the equation is instead in the denominator, with the error resulting in greater tonnage of dry coal than wet coal. This incorrect equation was also used in EPA's analysis [EPA, 2019a; ERG, 2019a]. Details of the calculation error are provided in Appendix E. Table 7-1 presents the range and average of the errors for the 63 plants that did not blend coal or burn multiple coal ranks, out of 70 plants that EPA considered in the bromide evaluation. The average high bias in dry coal tonnage ranged from 9% for plants that burned only bituminous coal to 146% percent for the two plants that burned only lignite coal.

Table 7-1
Error in dry coal tonnage on a plant basis

Coal Type	EPA Plant Count	Average Error	Minimum Error	Maximum Error
Bituminous	54	9%	4%	18%
Subbituminous	7	83%	55%	89%
Lignite	2	146%	127%	164%

Data source: EPA, 2019a
Plant Count = number of plants firing only the coal type indicated; if a plant fired multiple coal ranks, the error could not be determined from information provided by EPA.

EPRI identified two other oversights in EPA's methodology. In the first case, ERG [2019a] applied a plant-wide average coal moisture to each individual unit within the plant, even though there were sometimes differences in the coal types fired between units at the same plant. Since some units within a plant were excluded from EPA's bromide analysis, using the plant-wide moisture did not yield an accurate estimation of the dry coal consumption for the plant. In the 7-2
second case, to calculate the mass of bromide in coal burned in a plant, ERG [2019a] applied a weighted average bromide content calculated from the wet tonnage of each coal type. The weighting should have used dry coal tonnage, as the bromide concentration in each coal is based on dry coal. The resulting biases in dry coal tonnage and bromide mass associated with these errors could not be determined precisely from the information provided.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 51

Comment Excerpt:

7.1.2 **EPA appears to have overestimated mass loadings from pre- and post-combustion bromide addition.**

EPA derived assumptions on current bromide addition rates from an EPRI [2015] report, one of an annual series of EPRI member surveys on balance-of-plant effects of bromide addition conducted between 2012 and 2017. The more recent surveys in this series found that most electric generating units (EGUs) had reduced levels of bromide in refined coal and/or bromide addition to coal. These bromide reductions were due to problems with equipment corrosion as well as the understanding that lower levels of bromide could provide adequate control of mercury emissions for compliance with the Mercury and Air Toxics Standards (MATS) regulations. Of the EPRI [2017] survey respondents that reported using refined coal or bromide addition to coal—and whose EGUs were still in operation as of December 31, 2018—the median addition rate for all coal types was 60 parts per million (ppm), dry coal basis [EPRI, 2019]. The median addition rates reported in the most recent survey response for each EGU were significantly lower than the values used by EPA: 110 versus 298 ppm for units burning bituminous coal and 10 versus 97 ppm for units burning subbituminous coal (see Appendix E.5).

For units that reported adding bromide post-combustion for mercury control (i.e., brominated powdered activated carbon or Br-PAC), EPA estimated the equivalent bromine concentration in dry coal that might enter an FGD based on an EPRI [2013] bench-scale study of bromine volatilization from eleven activated carbons. This study was conducted by flowing a synthetic coal combustion flue gas through a heated, fixed bed of carbon and sand for 120 minutes. EPA used the average of the tests conducted at 700°F in their analysis, and did not incorporate results from tests conducted at 300°F. There are two ways in which EPA's approach may overestimate bromide volatilization. First, in the EPRI study, volatilization occurred under isothermal conditions for an extended time period, while the residence time of flue gas in a power plant duct is measured in seconds before the gas cools to the point that no further volatilization will occur. Second, EGUs where Br-PAC is injected downstream of an air heater are likely to see less volatilization than EGUs where Br-PAC is injected upstream of an air heater. The EPRI study showed that bromide volatilization at a temperature of 300°F (typical of downstream air heater temperature) was half the value measured at 700°F (typical temperature just upstream of the heater). In the most recent EPRI survey of Br-PAC addition [EPRI, 2014], 7 out of 17 survey participants reported injecting Br-PAC downstream of the air heater.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 9

Comment Excerpt:

Key Comments on Bromide

EPA's bromide mass loading and transport model appears to have overestimated the amount of bromide reaching downstream drinking water treatment systems from current coal-fired power plant discharges.

Commenter Name: Kelly D. Good, Ph.D., P.E.
Commenter Affiliation: Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8299-A1
Comment Excerpt Number: 1

Comment Excerpt:

Bromide was discussed extensively in the 2015 ELGs, and it is discussed extensively in this 2019 proposed rule. Although bromide is known to be present in fossil fuel-associated wastewaters, including flue gas desulfurization (FGD) wastewater, a lack of adequate effluent monitoring data makes it challenging to assess potential impacts of these bromide discharges on downstream drinking water sources. In response to this challenge, we developed a mass loading model to estimate the quantity of bromide discharged by FGD wastewater systems (Good and VanBriesen 2016). In the supporting documentation for this rulemaking, our work is cited in the approach used in DCN SE07260 (MassBalance Approach to Estimating Bromide Loadings from Steam Electric Power Plants).

We would like to communicate a recent correction to the method we developed. As described in the journal correction (Good and VanBriesen 2020a), the conversion of coal consumption data from 'as received' to dry basis was done incorrectly. Rather than multiplying by (1-moisture content), the analyses incorrectly divided by that term. The effect of this correction is that it reduces the mass of coal consumed, and therefore when incorporated into the model, reduces the estimated bromide loads from wet FGD discharges. When this correction is applied, the changes to the model-predicted bromide loads remain within the range of uncertainty of the model. This uncertainty is due to the uncertainty in model parameters (e.g., the estimate of the fraction of bromine captured in wet FGD) and the variability in the measured values used as input to the model (e.g., the coal moisture and bromine concentrations reported in the U.S. Geological Survey COALQUAL database). Additional details are provided in the correction itself, but it is important to note that while the correction changed the modeled values, the overall conclusions of the paper remained unchanged.

This error was carried into analyses we subsequently published (Good and VanBriesen 2017, 2019). In the corrections to these papers (Good and VanBriesen 2020b; c), as in the original, due to the small values involved and the many assumptions and wide ranges of input values used in the other parts of the model, the changes to the simulation estimates were small. After correction, there were no changes to the conclusions drawn from the analyses.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 82

Comment Excerpt:

1. EPA Overestimates Consumption of Dry Coal Tonnage.

Importantly, EPA's first step in this analysis—on which the rest of calculations are based—is significantly flawed. According to the BCA, EPA estimated steam electric power plant-level bromide loadings associated with FGD wastewater using the approach described in the Supplemental TDD.[139] The Supplemental TDD notes that EPA estimated plant-specific bromide loadings for each plant using a mass balance approach, described in further detail in ERG's memorandum titled *Mass-Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants.*[140, 141] Like the equation used in the Good and VanBriesen articles, "Equation 1," which appears on page 9 of EPA's memorandum, incorrectly includes the "(1 - moisture content)" variable in the denominator, when it should be in the numerator.[142] When applied, this equation produces higher values for dry coal tonnage than wet coal tonnage, an improbable result. Although ERG made modifications to the methodology described in the Good and VanBriesen papers,[143] it still relied on the erroneous formula. Thus, based on this error alone, it is likely that EPA has overestimated the consumption of dry coal tonnage by 9 percent for bituminous coal, 83 percent for subbituminous coal, and 146 percent for lignite coal.[144] Given this error, EPA has inflated the bromide loadings to surface water from coal-fired power plants.

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139 BCA at 4-5.
140 Supplemental TDD at 6-6.
141 ERG, EPA-HQ-OW-2009-0819-8242 at 9.
142 Id.
143 Id. at 4-5.
144 EPRI 2020 Comments Table 7-1.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 83

Comment Excerpt:

2. EPA Overestimates Bromide Addition Rates.

Either before or after the combustion process, facilities may introduce certain compounds that contain bromide to facilitate compliance with mercury air emissions limits. To account for bromide addition in EPA's analysis, EPA used aggregated data from bromide addition rates that were reported in 2015 to EPRI. EPA, in reliance on this 2015 survey, assumes a bromide addition rate of 298 ppm for units burning bituminous coal, 97 ppm for subbituminous coal, and 97 ppm for lignite coal.[145] As noted above, more recent surveys from 2016 and 2017 show that bromide addition rates have declined as power plant operators gained more experience with mercury control and because of concerns with cost and corrosion effects from the addition of bromide.[146] The median addition rates reported in the 2017 survey were significantly lower than the figures used by EPA. Whereas, EPA used 298 ppm for units burning bituminous coal, respondents reported an average of 110 ppm.[147] And for subbituminous coal where EPA used 97 ppm, respondents reported an average of 10 ppm.[148]

3. EPA Does Not Consider the Retirement or Conversion of Coal Plants.

For the BCA, EPA also compared exposure to baseline TTHM levels (i.e., prior to 2021 and the implementation of the regulatory options) with the alternative TTHM levels from 2021 through 2047.[149] As described in Section 4.3.3.3 of the BCA, this period of analysis is based on the approximate life span of the longest-lived compliance technology (20 or more years) and the final year of implementation (2028).[150]

[145] ERG, EPA-HQ-OW-2009-0819-8242 at 11.
[146] *See supra* Section XIV.E.3; EPRI Bromide Report at 3-2.
[147] EPRI 2020 Comments at E-3 (citing EPRI, *Mercury and Air Toxics Control: 2017 Update,* No. 3002010378).
[148] Id.
[149] Id.
[150] BCA at 4-13.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 20

Comment Excerpt:

FirstEnergy is also aware of several papers and models that have been used or relied upon by others to make claims about bromides contributing to disinfection byproducts at drinking water plants, specifically in FirstEnergy's territory. Good and VanBriesen performed modeling in 2016 and 2017 on the Allegheny River and Pennsylvania watersheds where Fort Martin and Harrison facilities are used in the analysis.[5,6] The Fort Martin and Harrison facilities were improperly represented in the analysis. Fort Martin does not add bromide which incorrectly exacerbated the modeling results. See EPA-HQ-OW-2009-0819-7310, Page 7. Harrison has not had an FGD discharge which was further exacerbated in modeling by showing native and added bromide being discharged to the receiving stream. These 2016 and 2017 studies inaccurately laid foundational framework which was used to develop national models for bromides and trihalomethane formation, some of which EPA relied upon in the docket's supporting information.

In addition to the flawed inputs into the model, the models were never validated. As UWAG points out in their comments, the Cornwell model showed bromide levels in the Ohio River as high as 222 µg/L; however, the Ohio River Valley Water Sanitation Commission ("ORSANCO") was already monitoring for bromide in the river.[7] The highest monitoring station on the ORSANCO dataset was the McAlpine station, and it was 52 µg/L for the same period as the Cornwell model, a modeled overestimation of over 300 percent. The Good and VanBriesen models were also never validated.

5 Kelly D. Good and Jeanne M. VanBriesen. *Power Plant Bromide Discharges and Downstream Drinking Water Systems in Pennsylvania.* Environmental Science & Technology 2017 51(20),11829-11838. DOI: 10.1021/acs.est.7b03003

6 Kelly D. Good and Jeanne M. VanBriesen. *Current and Potential Future Bromide Loads from Coal-Fired Power Plants in the Allegheny River Basin and Their Effects on Downstream Concentrations*. Environmental Science & Technology 2016 50(17),9078-9088. DOI: 10.1021/acs.est.6b01770
7 Cornwell, D. A., Baljit, K. S., Brown, R., and McTigue, N. E., *Modeling Bromide River Transport and Bromide Impacts on Disinfection Byproducts*, Journal of the American Water Works Association, Volume 110, Issue 11, EPA-HQ-OW-2009- 0819-7856 (Nov. 2018).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 72

Comment Excerpt:

E. The Scientific Literature that Describes the Threat of Bromides from Power Plants Contains Critical Flaws.

The journal articles on which the drinking water utilities have predominantly relied[114] to describe the threat of bromides from power plants contain significant errors. Due to recent retirements of coal-fired power plants, changes in industry practices, the use of conservative estimates in the articles' calculations, and an explicit error in an equation that likely permeates throughout the research, the articles overestimate the quantity and potential impact of bromide discharges.

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[114] EPA also references these studies for various purposes. See, e.g., EPA, *Benefit and Cost Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* EPA-821-R-19-011, EPA-HQ-OW-2009-0819-8238 (Nov. 1, 2019) ("BCA") at 4-1; Supplemental EA at 2-4; Supplemental TDD at 6-6; ERG, *Memorandum re: Mass-Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants (DCN SE07260),* EPA-HQ-OW-2009-0819-8242 (Oct. 28, 2019) ("ERG, EPA-HQ-OW-2009-0819-8242") at 4.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 73

Comment Excerpt:

1. The Articles Overestimate the Number of Power Plants Discharging FGD Wastewater.

The scope of this issue is more limited than some would suggest. In comments and a letter to EPA regarding discharges of bromide, AWWA claimed there are "407 coal-fired power plants with the potential to impact at least 573 drinking water treatment facilities downstream from them."[115] In addition, the scientific articles cited in the administrative record for the Proposed

Rule also significantly overstate the number of coal-fired power plants that discharge FGD wastewater to surface waters. For example, the 2019 Good and VanBriesen study[116] identified and evaluated bromide mass loadings to surface water from 116 coal-fired power plants. According to the U.S. Energy Information Administration ("EIA") and other industry information current as of December 31, 2018, however, there are only 87 electric generating units with at least one operable wet FGD system discharging to surface water. Further, of the seven facilities on the Ohio River modeled by Cornwell (2018),[117] two are no longer in operation, and one does not discharge to surface water. Therefore, the number of power plants that could potentially discharge bromide to water treatment facilities is approximately 25 percent less than that used in the Good and VanBriesen (2019) analysis and over 75 percent less than the 407 power plants cited in research papers and comments submitted to EPA. As a result, the potential impact to downstream water treatment plants is also considerably less, and the overall scope of this issue is much smaller than some have claimed.

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[115] AWWA and AMWA, EPA-HQ-OW-2009-0819-7598 at 1; see also 84 Fed. Reg. at 64,642 (citing AWWA letter).

[116] Good, K.D., and J.M. VanBriesen, *Coal-Fired Power Plant Wet Flue Gas Desulfurization Bromide Discharges to U.S. Watersheds and Their Contributions to Drinking Water Sources,* 53 Environ. Sci. Technol. 213-223 (2019) ("Good and VanBriesen (2019)").

[117] Cornwell, D. A., K.S. Baljit, R. Brown, and N.E. McTigue, *Modeling Bromide River Transport and Bromide Impacts on Disinfection Byproducts,* JOURNAL OF THE AMERICAN WATER WORKS ASSOCIATION, Volume 110, Issue 11, EPA-HQ-OW-2009-0819-7856 (Nov. 2018) ("Cornwell (2018)").

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 74

Comment Excerpt:

2. The Articles Overestimate the Quantity of Bromide Within Coal.

Similarly, the quantity of bromide in FGD wastewater has also been overestimated. To estimate bromide loadings in FGD wastewater, the research does not rely on data from direct monitoring of the wastewater discharges; rather, the calculation is based on the facility's estimated coal consumption, the potential chloride in coal, and an assumed 0.02 bromide to chloride ratio in all coals. This approach has a number of flaws. Chiefly, bromide content varies considerably among the various types of coal burned by power plants. For example, the estimated bromide content used by Good and VanBriesen (2019) was higher than the content of the vast majority of coal normally used at power plants. Due to a metric based on data availability rather than actual coal usage, the data used in Good and VanBriesen (2019)'s bromide mass load calculations overestimated nationwide concentrations by 58 percent for bituminous coal, 5 percent for subbituminous coal, and 50 percent for lignite.[118] Cornwell (2018) also calculated the bromide content using a maximum bituminous coal concentration, resulting in an extreme outlier.[119]

Most importantly, Good and VanBriesen, in multiple articles, rely on an equation that contains two significant errors associated with how they calculated bromide mass loadings from each facility.[120] To calculate dry coal tonnage, Good and VanBriesen attempted to convert as received (wet) coal weight to dry coal weight, so that the coal amount could be combined with the bromide concentration in parts per million, dry. However, the equation incorrectly includes the "(1 - moisture content)" variable in the denominator, when it should be in the numerator.[121] Second, the equation as written should use a moisture content fraction, not a percent. When the erroneous formula is applied, it overestimates the mass of bromide by 14 percent for bituminous coal, 88 percent for subbituminous coal, 130 percent for lignite coal, and 42 percent for refined coal.[122] Thus, when one combines the inflated bromide concentrations, discussed above, with this flawed equation, the results in the scientific literature overestimate bromide mass loadings to water by 80 percent for bituminous coal, 98 percent for subbituminous coal, and 245 percent for lignite coal.[123] Because of the significant overestimate of mass loadings, the potential quantity of bromide in FGD wastewater is considerably less than what the research indicates.

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[118] EPRI, *Impacts of Bromide from Power Plants on Downstream Disinfection Byproduct Formation: A Literature Review,* No. 3002017477 (Nov. 2019) ("EPRI Bromide Report") at 2-7.
[119] Id.
[120] Id. at 6-2.
[121] The authors have acknowledged this error and they have submitted a correction to the journal. See AWWA, *Methods to Assess Anthropogenic Bromide Loads from Coal-fired Power Plants and Their Potential Effect on Downstream Drinking Water Utilities* at 41 n.6 (Dec. 2019).
[122] EPRI Bromide Report at 6-2.
[123] Id. at 6-3.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 75

Comment Excerpt:

3. The Scientific Literature Relies on Outdated Bromide Usage Surveys.

Conducted prior to 2013, the surveys cited in the recent literature also overstate the amount of bromide added to refined coal or for mercury control. Based on these outdated surveys, Cornwell (2018) assumes a worst-case scenario of bromide added per kilogram of dry coal of 300 mg (or 300 ppm) and Good and VanBriesen (2019) at 216 assumed a baseline bromide addition of 100 ppm and a maximum of 460 ppm.[124]

Surveys conducted from 2014-2017, however, show that bromide addition rates declined dramatically as power plant operators gained more experience with mercury control and due to concerns with cost and corrosion effects.[125] For example, by reducing bromide levels, plant operators learned they can sufficiently control mercury emissions for compliance with the Mercury and Air Toxics Standards regulations ("MATS rule"). Based on the data from the more recent surveys, approximately 83 percent of the electric generating units with wet FGDs had bromide addition rates of 120 ppm or less, and the median usage was 60 ppm.[126] Moreover, of the remaining 17 percent of facilities that added bromide at rates above 120 ppm, all are zero liquid discharge ("ZLD") plants. In other words, Cornwell's 300 ppm estimate *is nearly three times the highest rate reported in the updated survey data*, and Good and VanBriesen's baseline of 100 ppm *is nearly double the median usage in the most recent data.*

[124] Good and VanBriesen (2019).
[125] EPRI Bromide Report at 3-2.
[126] Id.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 12

Comment Excerpt:

Also, some existing research purporting to estimate power plant discharges of bromide has significant flaws and, as such, does not provide a reliable basis for regulation. Further, EPA's estimates of bromide discharges also suffer from problems with inputs to the model that overestimate the bromide additions and inherent limitations with the modeling.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 9

Comment Excerpt:

As addressed more fully in the UWAG comments, there are significant flaws in the existing research purporting to estimate power plant bromide discharges and EPA's modeling overestimations loadings of the constituent. Neither should not be used to justify regulation as part of the sectors effluent guidelines.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 76

Comment Excerpt:

4. Discharges of Bromide are Likely to Decrease Over Time.

Claims in the drinking water utilities' June 2018 letter that bromide discharges will increase absent CWA controls are also incorrect. There are many coal-fired power plants retiring and less frequent dispatch of the remaining coal-fired power plants. According to EPA's records, at least 78 plants (160 units) have or will be retire or convert to non-coal fuels between the summer of 2014 and December 31, 2028.[127] These numbers have been verified by information directly from the plant operating company or a government entity.[128] Furthermore, coal consumption for U.S. electricity generation has declined by 26 percent from 2013 to 2018[129] and will continue to decline as coal-fired power plants close. In addition, plants that continue to operate have already added scrubbers to comply with the Maximum Achievable Control Technology rule. As a result, there are very few new wet scrubbers that will be added to existing coal-fired plants. In fact, only one new, small coal-fired unit (17 MW) came online in 2019.[130] Thus, contrary to AWWA's claims, the amount of bromide discharged to surface waters is likely to decrease over time as the use of coal to generate electricity also decreases.

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[127] EPA, Supplemental TDD, at 3-2 – 3-3.
[128] ERG, *Memorandum re: Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule – DCN SE07207,* EPA-HQ-OW-2009-0819-7373 (July 31, 2019) ("ERG, 2019 Industry Change Memo") at 2.
[129] U.S. EIA, *Electricity Data Browser, Data Set – Consumption for Electricity Generation,* http://www.eia.gov/electricity/data/browser/#/topic (last visited Jan. 14, 2020).
[130] University of Alaska Fairbanks, "UAF Heat and Power Plant Major Upgrade Project," *Combined Heat and Power Plant,* www.uaf.edu/heatandpower, https://www.uaf.edu/heatandpower/files/CHP_briefing_2013.pdf (last visited Jan. 14, 2020).

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 2

Comment Excerpt:

Any assessment of a potential regulatory approach to iodine must take into account the small quantities typically used by power plants for mercury reduction purposes as compared to naturally occurring iodine and non-coal sources of iodine.

Mercury control using iodine requires significantly less volume of added reagent than bromine based approaches. In fact, iodine application levels are on average less than one-tenth the level of bromine that would be needed to achieve similar levels of mercury emissions reductions. Some U.S. power plants have reported bromine application rates more than 100 times the Tinuum iodine application rate. As a result, any assessment of the environmental impact of the two halogens needs to start with an understanding that the volume of supplemental iodine would be a small fraction of the bromine at a similar power plant.

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 3

Comment Excerpt:

All coals contain some level of native halogen, whether fluorine, chlorine, bromine or iodine. Limited data is available on native levels of iodine in all coal sources and ranks across the U.S. What data exists indicates that native levels of iodine in Eastern bituminous coal range to levels several times the Tinuum application rate.

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 8

Comment Excerpt:

As noted in the NPRM, the regulation of one form of pollution may aggravate other environmental problems. In this case, the potential regulation of iodine at coal-burning power plants would significantly impair compliance with other environmental regulations. Any proposed regulation of the use of iodine – or halogens broadly – by coal-burning power plants must take into account the purpose for which such plants would apply supplemental halogens.

Use of halogens in connection with coal combustion is a critical tool for power plants to reduce mercury emissions and comply with MATS. Iodine has been used for mercury emissions reductions at coal-burning power plants for more than 10 years, preceding the adoption of the MATS rule. Since the 2012 publication date of the MATS rule and accelerating near the 2016 effective date for MATS, the number of power plants using iodine for mercury control has increased. An estimated 80% of U.S. coal-burning power plants rely on some form of supplemental halogen as part of their mercury emissions control program. While power plants using bromine are estimated to comprise approximately 80% of that total, stations using iodine constitute a meaningful portion of U.S. power production, likely in the 15% - 20% range. An estimated one-third of the power plants using supplemental halogens also operated a wet scrubber and would be directly impacted by inclusion of halogens in the Steam Electric ELG.

The high percentage of U.S. power plants using halogens for mercury emissions control suggests that alternative technologies are both less effective and more expensive. In fact, Tinuum understands that available and economically viable alternatives to halogens for broad MATS compliance have not been proven. Restrictions on iodine or other halogens for coal-burning power plants should be considered, if at all, only after effective and economic MATS compliance alternatives have been proven. If there are no economic alternatives for power plants to comply with MATS, any regulation of halogens would have to consider impacts on compliance with the MATS rules as well as the impacts to cost and reliability of electric generation.

The discussion in the NPRM of Non-Water Quality Environmental Impacts does not include any empirical assessment of the impact on MATS compliance of a determination to include iodine or other halogens in the Steam Electric ELG. Absent such assessment, it is not possible to fully assess the costs and benefits of any proposed regulation of iodine or other halogens.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 82

Comment Excerpt:

'Halide salt' fuel additive and activated carbon injection are sometimes used by plants to help control mercury and air toxic emissions. Both are commonly laced with bromide. These brominated additives are then captured by the plant's scrubber and discharged with the scrubber wastewater into wastewater basins, which in turn discharges into rivers, lakes, and streams.

Brominated additives to coal operations have been an issue in the Southeast. For example, in 2017 at the Allen and Marshall coal plants in North Carolina,[274] NC DEQ proposed to increase the level of allowed brominated additives, even though Duke Energy's wastewater discharge of bromide contributed to the formation of carcinogens in downstream drinking water intakes serving more than a million people.[275] Following public scrutiny and a lawsuit filed over the Allen permit by the Southern Environmental Law Center, NC DEQ reversed course on the Allen and Marshall permits, and Duke Energy removed halide salts from its operations. NC DEQ subsequently issued permits prohibiting the use of "halogen containing compounds (e.g. bromide)."[276] See the attached comment letters to the NC DEC for more information on bromide problems in North Carolina.[277] Brominated additives are also an issue in Virginia. Although such use has apparently ceased, Dominion Energy was permitted to use up to 6,500 tons per year of a halide salt (calcium bromide) at its Chesterfield Power Station on the James River in Virginia.[278]

[274] Fortunately, Duke Energy has since removed halide salt additives from its operations. See letter from Duke Energy to NC DEQ, June 12, 2017 (Attachment 81).
[275] See Letter from Southern Environmental Law Center to NC DEQ, April 28, 2017 (Attachment 82) ("Marshall Comment Letter"); letter from Southern Environmental Law Center to NC DEQ, Feb. 27, 2017 (Attachment 83) ("Allen Comment Letter").
[276] See e.g., NC DEQ, Air Quality Permit No. 03757T43 (Sept. 15, 2017) (Attachment 84).
[277] Id.
[278] See Dominion, Operation & Maintenance Manual VPDES Discharge Facilities, Chesterfield Power Station, 23 (June 12, 2012) (Attachment 85) (excerpts).

14 FGD Wastewater – Chemical Precipitation

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 2

Comment Excerpt:

EPA appears to have underestimated FGD chemical precipitation equipment redundancy. In order to provide a more accurate cost estimate, EPRI recommends using 2x100% trains for plants with high capacity factors, and 2x60% at plants with lower capacity factors

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 17

Comment Excerpt:

2.4 **EPA underestimated required FGD chemical precipitation equipment redundancy.**

The cost of chemical precipitation treatment is significantly affected by the approach used to define redundancy in treatment trains. The redundancy required differs from the redundancy of specific mechanical equipment (such as providing a spare pump); but rather refers to defining redundant treatment trains in terms of major equipment such as clarifiers. Most treatment systems for critical functions include redundant trains in case of failure or for use during maintenance.

There is then a question of the size of each train. A conservative approach is to provide capacity to treat the entire peak design flow with one train out of service, which can be done with 2x100% or 3x50% sizing. Providing smaller trains (such as 2x60%) is used in some situations where the risks associated with not being able to treat all the water all the time are considered acceptable. In 2013, EPA assumed treatment trains of 2x60% [EPA, 2015]. EPRI commented that a more appropriate sizing is 2x100%. In 2015, EPA rejected this comment. Based on how newer treatment systems are being designed and operated, EPRI understands that the industry's approach to response to redundancy will generally vary, based on different utility operational strategies as well as base load versus peaking units. EPRI believes that redundancy is best represented by a range of system redundancies and has assumed, with member feedback, that plants with a reported capacity factor greater than 60 percent (26 percent of the coal generation industry) would install a 2x100% redundancy system. Similarly, EPRI assumes that the remaining plants with reported lower capacity factors (74 percent of industry plants) would install a 2x60% redundancy system.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 63

Comment Excerpt:

A —APPENDIX: FGD WASTEWATER TREATMENT COST METHODOLOGY—CHEMICAL PRECIPITATION

A.1 Cost estimating summary for chemical precipitation of flue gas desulfurization wastewater

A.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the cost of chemical precipitation (CP) treatment of flue gas desulfurization (FGD) wastewater to the steam electric industry based on EPA's industry profile [ERG, 2019a]. This technical memorandum describes the method for calculation of costs of chemical precipitation treatment for an individual plant, the assumptions associated with the cost calculations, and the estimated costs for chemical precipitation treatment to the steam electric industry. Table A-1 outlines the cost to the current industry to install chemical precipitation treatment of FGD wastewater.

Table A-1
Chemical precipitation treatment costs to industry for FGD wastewater, in June 2018 dollars

Capital Costs ($M)	Operating Costs ($M per year)	Annualized Cost [a] ($M per year)
1,652	46	202

M = million
$ = U.S. dollars (June 2018)
[a] Annualized cost based on 20-year equipment life and 7% interest rate.
Costs represent EPA's 2019 plant list [ERG, 2019], adjusted to account for retirements of R. D. Morrow (ID 1185) and Units 1 and 2 of Chesterfield Power Station (ID 4679) as of the end of 2018. EPRI's list also does not include Lewis & Clark (ID 394) which is at the 50-MW limit.

A.1.2 Introduction

The U.S. Environmental Protection Agency (EPA) updated the Steam Electric Power Generating effluent limitation guidelines (ELGs) through a comprehensive information collection request (ICR) and sampling at FGD wastewater treatment systems. Following the ICR, the EPA published a draft ELG rule in 2013. EPRI previously provided estimated costs for FGD wastewater treatment technologies as a part of comments during the 2013 ELG rulemaking. The ELG rule was later finalized in 2015 but is now being reconsidered for FGD wastewater. Therefore, EPRI has prepared updated cost estimates of FGD wastewater treatment technologies for commenting on the revised draft ELG rule. The treatment technologies evaluated were (1) chemical precipitation, (2) biological, (3) chemical softening followed by vapor-compression evaporation/ crystallization (CS + VCE/CRX), (4) chemical precipitation followed by vaporcompression evaporation and brine solidification (CP+VCE/BS), (5) chemical softening followed by seawater reverse osmosis (SWRO) and brine solidification (CS + SWRO/BS), and (6) chemical precipitation followed by advanced membrane filtration (AMF) and brine solidification (CP+AMF/BS). The technologies are discussed in separate Appendices A thru D, with Appendix A addressing chemical precipitation. The cost evaluation results for chemical precipitation, biological and CS + VCE/CRX treatment were extrapolated industry-wide.

A.1.3 Chemical precipitation treatment overview

The chemical precipitation treatment system used to evaluate costs for the industry consists of equalization, desaturation, chemical addition to enhance metals removal, clarification, neutralization, media filtration, and solids dewatering. Figure A-1 shows a simplified process flow diagram of this chemical precipitation treatment system.

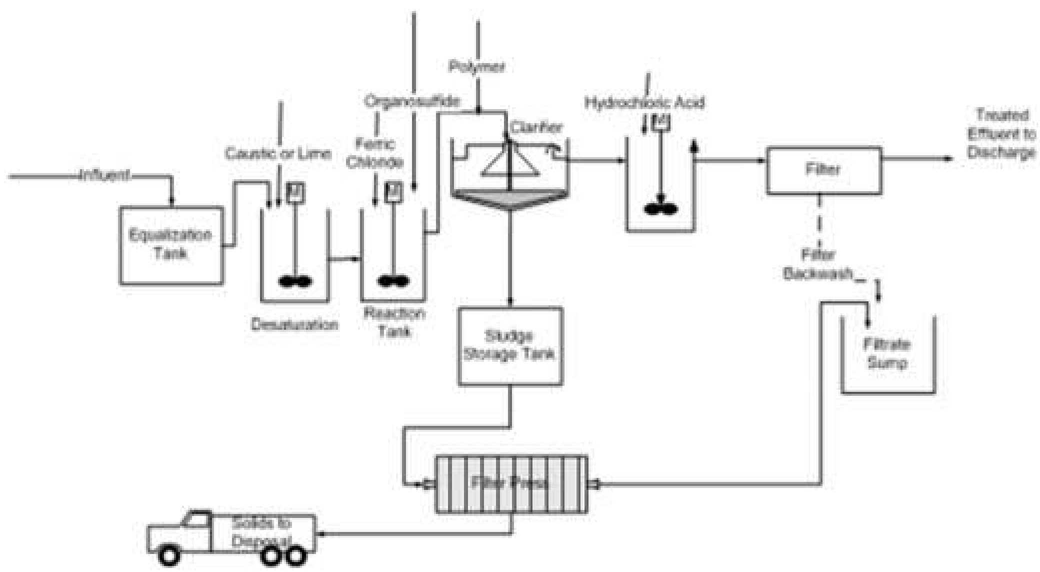

Figure A-1
Chemical precipitation treatment system

A.1.4 Conceptual design basis

The design basis for the cost estimate is described in this section.

A.1.4.1 Flow rate basis

Flow capacity is a key factor in the cost of many treatment components. Peak flow rate is the main consideration in sizing equipment. Average flow rate has a large impact on operating cost elements such as chemical feed, waste disposal, and electricity. EPA provided updated FGD purge flows for all plants in Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings – DCN SE07091 [ERG, 2019]. EPRI reviewed the flows reported by EPA and used best professional judgement to resolve flow changes from the 2009 ICR response. Then EPRI estimated a peak flow for each plant in one of four ways:

- If EPA's 2019 FGD purge flow matched the plant's reported typical purge flow (ICR response B5-2) or if it appeared that EPA made reasonable adjustments to the plant's reported typical purge flow based on units added/retired since the ICR response, then EPRI used EPA's assumed FGD purge flow. To determine peak flow, EPRI multiplied EPA's FGD purge flow by a peaking factor of 1.5.
- For two plants, there was insufficient information to understand why EPA had reduced the plant's reported purge flow since the ICR response. For these plants EPRI used the plant'soriginal ICR response for FGD purge flow (ICR response B5-2) and then applied a peaking factor of 1.5 to determine the plant's peak flow.
- EPRI used the plant's reported peak wastewater treatment system (WWTS) design flow (ICR response D5-3), where it was more suitable in EPRI's best professional judgment. No peaking factor was applied where EPRI used the plant's reported peak WWTS design flow.
- For two plants, EPRI used a peak flow basis derived from the original FGD WWTS design flow (ICR response D5-3), which was adjusted based on units added/retired since the ICR response.

The peak flow rate was used to size all equipment to determine the capital cost of the system.

EPRI estimated an average flow for each plant in one of three ways:

- If EPA's 2019 FGD purge flow matched the plant's reported typical purge flow (ICR response B5-2) or if it appeared that EPA made reasonable adjustments to the plant's reported typical purge flow based on units added/retired since the ICR response, then EPRI used EPA's assumed FGD purge flow.
- For two plants, EPRI developed an assumed average flow by dividing the assumed peak flow by a peaking factor of 1.5.
- For one plant, EPRI used the original ICR response for FGD purge flow (ICR response B5-2), where there was insufficient information to understand why EPA had reduced the plant's reported purge flow since the ICR response.

The average flow rate was used to calculate the operations and maintenance (O&M) cost of operating the treatment system.

A.1.4.2 Feed water quality characteristics

Equipment is generally sized using peak flow rate. However, peak solids loading is used to size solids dewatering equipment and estimate solids disposal costs. EPRI estimated solids loading using ICR-reported influent total suspended solids (TSS) (B5-3, typical solids content of the untreated FGD scrubber purge [or slurry discharge] transferred to the wastewater treatment system after the FGD solids separation process but prior to comingling with other FGD wastewater). The mean TSS from the ICR data set for plants with less than 55,000 milligrams per liter (mg/L) TSS was 10,771 mg/L. If TSS data for a plant were not provided in the ICR, average influent TSS concentration was assumed to be 10,771 mg/L and peak influent TSS was assumed to be 1.5 times the mean, or 16,157 mg/L.

There was one facility with TSS above 55,000 mg/L. EPRI assumed that this facility would likely employ a solids separation process upfront, rather than send this high loading of solids to a wastewater treatment plant where dewatering costs would be very high. EPRI further assumed that this plant would use mechanical dewatering in the FGD system to achieve average TSS of 10,771 mg/L and peak TSS of 16,157 mg/L.

EPRI assumed that corrosion-resistant materials were used for process equipment due to the high chloride levels typically present in FGD wastewater.

A.1.5 Cost development methods

A.1.5.1 Equipment cost assumptions

For each subsystem in the treatment train, a cost curve was developed as a function of a key variable affecting cost. The curves included the expected cost, based on the cost of the elements that made up the subsystems (for example, pumps, mixers, and tanks). The equipment in each subsystem and the design criteria used for equipment sizing are shown in Table A-2. The curves were built by developing cost estimates for equipment at seven different flow rates: 25, 50, 100, 200, 400, 600, and 800 gallons per minute (gpm). Costs were zero for a subsystem if it was not needed at a site.

EPRI compared the cost curves it generated with the available cost curves provided by EPA in the appendices of Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category [EPA, 2013]. EPRI also reviewed the available design assumptions presented in the appendices of this document. Costs were generally comparable between the EPRI and EPA estimates.

Table A-2
Equipment cost assumptions

Equipment	Design Criterion	Unit	Sizing
Equalization			
Equalization tank	Hydraulic detention time at peak flow rate. FRP tank with dip tube, baffles, and bridge for top-mounted mixer(s); top-entry mixer(s) made of material that resists chloride corrosion	hr	12
Equalization tank mixer(s)	Number and size of mixers based on professional judgment.	hp/1,000 gal	0.1
Desaturation			
Desaturation tank	Hydraulic detention time at daily peak flow rate	min	40
Desaturation tank mixer	Number and size of mixers based on professional judgment	hp/1,000 gal	1
Lime feed system: silo	Lime storage	days	15
Lime feed system: dry feeder	Dose	mg/L (chemical/ wastewater)	3,000
Metals Removal			
Organosulfide chemical feed system	Dosage based on industry experience	mg/L (chemical/ wastewater)	30

Table A-2 (continued)
Equipment cost assumptions

Equipment	Design Criterion	Unit	Sizing
Solids Removal/ Clarification			
Reactor tank	Hydraulic detention time at peak flow rate Includes FRP tank with dip tube, baffles, and bridge for top-mounted mixer	min	20
Reactor tank mixer	Number and size of mixers based on professional judgment	hp/1,000 gal	1
Polyblend system	Dose	mg/L (chemical/ wastewater)	10
Ferric chloride feed pump system	Dose	mg/L (chemical/ wastewater)	100
Clarifier	Surface overflow rate Includes circular, steep floor, coated-steel clarifier; high-torque clarifier drive mechanism of stainless steel; picket fence floc mechanism	gpm/ft^2	0.33
Clarifier sludge pumps	Flow rate	gpm	50% of clarifier influent flow rate
Neutralization			
Acid feed system	Dose	mg/L (chemical/ wastewater)	20
Reactor tank	Hydraulic detention time Includes FRP tank with dip tube and bridge for top-mounted mixer	min	20
Reactor tank mixer	Number and size of mixers based on professional judgment	hp/1,000 gal	1
Media Filtration			
Filter	Flow rate Continuous backwash filter	gpm	Equal to wastewater flow rate
Effluent tank	Hydraulic detention time	min	20

Table A-2 (continued)
Equipment cost assumptions

Equipment	Design Criterion	Unit	Sizing
Solids Dewatering			
Sludge holding tank	Hydraulic detention time Includes FRP tank with bridge for top-entry mixer	hr	24
Sludge holding tank mixer		hp/1,000 gal	0.5
Filter press feed pump	Pump flow capacity Includes centrifugal type pump		Pump sized to fill press in 5 min
Filter press	Press size Includes chloride corrosion-resistant metallurgy feed piping and filter cloth wash tank		Press capacity sized so daily solids load can be dewatered in 8-hr operator shift, assuming each press cycle takes 2 hr
Support Equipment			
Waste sump	Based on best professional judgment	gal	6,000
Flushing pumps	Flow rate	gpm	Equal to wastewater flow rate
Seal water pumps	Flow rate	gpm	4% of wastewater flow rate

ft^2 = square feet
FRP = fiber reinforces plastic
gal = gallons
gpm = gallons per minute
hp = horsepower
hr = hours
L = liter
mg = milligram
min = minute
TSS = total suspended solids

A.1.6 Capital cost assumptions

A.1.6.1 Classification of estimate

The capital costs presented in this estimate are based on total installed costs, which typically include:

- **Direct costs** – equipment, freight, taxes, field construction (buildings, site work, concrete foundation, piping, mechanical, electrical, and field instrumentation and controls), general conditions, and bonding A-7
- **Indirect costs** – engineering, commissioning and start-up, contractor profit, and contingency for miscellaneous unidentified costs

The Association for the Advancement of Cost Engineering (AACE) International Recommended Practice 18R-97 [AACE International, 2011] provides guidelines classifying cost estimates and their relative accuracy. The accuracy of the cost estimate is generally a function of the amount of engineering completed at the time of the estimate. Table A-3 shows the class of total installed cost estimates, the relative accuracy, and the project definition percent complete for each estimate.

Table A-3
AACE cost estimating guideline

Estimate Class	Level of Accuracy (% of estimated cost)	Project Definition (%)
5	–50 to +100	0 to 2
4	–30 to +50	1 to 15
3	–20 to +30	10 to 40
2	–15 to +20	30 to 70
1	–10 to +20	50 to 100

Source: AACE, 2011.

This memorandum presents Class 4 estimates, generally defined as study- or feasibility-level estimates, for total installed costs. The purpose of a Class 4 estimate is to prepare for activities such as strategic planning and alternate scheme analysis. To prepare a Class 4 estimate, quotes should be obtained for major equipment items; however, according to AACE 18R-97, these estimates can be produced with parametric models and even cost factoring [CH2M HILL, 2009]. Class 4 cost estimates are not for any specific plant, but for a hypothetical set of conditions.

These estimates were prepared to guide evaluation of the technology and are based solely on the information available at the time of the estimate. Actual final costs will depend on the actual labor and material costs, competitive market conditions, site conditions, final project scope, implementation schedule, and other variable factors.

A.1.6.2 Cost model factors

System-wide cost factors were applied to develop the cost estimate (Table A-4). Values within the suggested ranges in Table A-4 are typically used in estimating costs of wastewater treatment plants. The mid-point of the suggested range for each cost factor was used to estimate costs for this evaluation unless noted otherwise.

Table A-4
Model cost factors

Additional Cost Items	Suggested Range (%)		Value Used (%)	Rationale for Selected Value
Site work	3.0	5.0	4.0	Mid-point of range
Concrete	15.0	20.0	17.5	Mid-point of range
Piping	6.0	8.0	25.0	Higher than range, assumes installation of high-grade alloy
Miscellaneous metals, finishes	5.0	15.0	10.0	Mid-point of range
Mechanical, heating/ventilation/air conditioning	5.0	10.0	7.5	Mid-point of range
Electrical (process electrical and site electrical)	14.0	30.0	22.0	Mid-point of range
Instrumentation and control	10.0	20.0	15.0	Mid-point of range
Subcontractor overhead	5.0	15.0	10.0	Mid-point of range
General contractor general conditions	11.0	14.0	12.5	Mid-point of range
Bonding and insurance	2.7	3.0	2.85	Mid-point of range
General contractor profit	14.1	14.4	14.25	Mid-point of range
Miscellaneous unidentified cost (contingency)	10.0	30.0	20.0	Mid-point of range
Engineering (design, services during construction, start-up, and operator training)	15.0	25.0	20.0	Mid-point of range

A.1.6.3 Major assumptions

The following additional assumptions were made:

- Freight cost will be 4 percent of the installed equipment cost.
- Materials resistant to high chloride concentrations will be needed for treatment equipment.
- Costs are presented in June 2018 dollars. Construction Cost Index values, as published by Engineering News Record (ENR) as of March 2019, were used to escalate costs to June 2018 pricing.
- Dewatering for construction is not required.
- The site is balanced cut/fill.
- Wastewater tie-in piping of 2,000 linear feet will be installed above ground.
- Seeding of disturbed areas is required.
- No painting of galvanized steel, aluminum, stainless steel, or polyvinyl chloride (PVC) material is required.
- Installation cost estimates are based on national averages.

- For all installation options, the sizes and quantities of all equipment were selected based on the system design redundancy. For example, the cost estimate for two trains at 100 percent capacity per train assumes that two tanks will be installed in parallel, both designed for 100 percent capacity. The only exception is filter presses used for dewatering; one spare filter press was assumed for all installation options.
- For all installation options, bulk chemical storage was provided, assuming 15 days of storage time at the design flow rate.
- No costs were included to account for cold weather protection for equipment installed outdoors (for example, heat tracing [except freeze protection for piping], insulation), installation of new utility services, new site development (for example, significant excavation), or installation in areas of limited footprint or remote locations involving delivery issues. These types of cost factors would increase cost estimates for the chemical precipitation treatment system.
- Project will be sales-tax exempt.
- Permitting costs are included.
- Costs of an onsite mercury analyzer are included [EPA, 2013].

A.1.7 Operations and maintenance costs assumptions

A.1.7.1 Cost elements

O&M requirements for this estimate include the following cost elements:

- Chemicals
- Electricity
- Residuals disposal
- Equipment maintenance
- Labor
- Compliance monitoring

A.1.7.2 Major assumptions

The major assumptions used in calculating these estimated O&M costs were:

- Costs are presented in June 2018 dollars. Construction Cost Index values, as published by Engineering News Record (ENR), were used to escalate costs to June 2018 pricing.
- Labor: a total of 4 full-time equivalents (FTE) operators at $49/hour and 1 supervisor at $76/hour were assumed to staff the treatment plant. One additional FTE at $49/hour is assumed to operate solids dewatering.
- Dosage rates will be typical values. [Actual dosage rates could vary depending on FGD wastewater chemistry.] Costs will be [actual costs will vary by geography, delivery method, and chemical supplier]:
- Lime - $0.09/lb
- Ferric chloride (35%) - $1.945/gallon
- Hydrochloric acid (30%) - $0.68/gallon
- Polymer - $1.86/lb

- Organosulfide - $11.71/gallon
- It is estimated that the FGD system will operate and generate wastewater less than 100% of the time. Net generation rates from 2017 were used to estimate each physical/chemical treatment system's online factor.
- Onsite mercury analyzer O&M costs are included [EPA, 2013].
- Residuals disposal unit cost of $54/ton on a dry-weight basis, which is based on EPA's disposal costs [EPA, 2013] and escalated to June 2018 dollars. EPRI developed the unit cost assuming that 25 percent of plants would use offsite landfills and 75 percent use onsite landfills.
- All wastes were assumed to be RCRA nonhazardous solids. All landfills were assumed to be lined and monitored.
- Electricity cost of $0.0523 per kilowatt hour.
- Annual equipment maintenance costs will be 3.0 percent of the total equipment costs.
- Compliance monitoring costs include costs for sampling and analysis of FGD wastewater effluent discharge.

A.1.8 Example cost estimate

The cost estimate for chemical precipitation treatment for an example system with peak design flow rate of 300 gallons per minute (gpm) and 2x100 percent redundancy is provided in the following subsections.

A.1.8.1 Capital costs

An example worksheet that shows the total estimated capital costs for a 300-gpm chemical precipitation treatment system is provided in Table A-5. The estimate below assumes 1 percent solids in the treatment system influent. The equipment costs are based on cost quotes provided by the equipment vendors. The cost model factors shown in Table A-4 are added to the purchased equipment cost to obtain a total estimated capital cost for the system.

Table A-5
Summary of estimated chemical precipitation treatment system capital costs for a 300 gallon-per-minute system

Cost Element	Chemical Precipitation Treatment ($)
Process Equipment by Subsystem	
Equalization	1,420,000
Desaturation	1,040,000
Metals Removal	60,000
Clarification	1,180,000
Neutralization	280,000

Table A-5 (continued)
Summary of estimated chemical precipitation treatment system capital costs for a 300 gallon-per-minute system

Cost Element	Chemical Precipitation Treatment ($)
Process Equipment by Subsystem (continued)	
Filtration	460,000
Solids Dewatering	1,760,000
Support Equipment (pumps, waste sump)	220,000
Freight (4%) and Taxes (0%)	257,000
Subtotal—Purchased Equipment Cost as Delivered	**6,677,000**
Installation	535,000
Additional cost items [a]	
Pre-engineered building [b]	4,714,000
Tie-in allowance [c]	163,000
Site work [d]	257,000
Piping	1,605,000
Mechanical/HVAC	482,000
I&C	963,000
Electrical	1,412,000
Concrete	1,124,000
Miscellaneous metals, finishes	642,000
Subtotal—Subcontractor Direct Cost	**18,574,000**
Subcontractor overhead and profit	1,857,000
Subtotal—Subcontractor Cost	**20,431,000**
General contractor general conditions [a]	2,554,000
Bonding and insurance [a]	582,000
Subtotal—Direct Costs	**23,567,000**
General contractor profit [a]	3,358,000
Subtotal	**26,925,000**
Miscellaneous unidentified cost (Contingency) [a]	5,385,000
Subtotal—Estimated Construction Cost	**32,310,000**
Engineering (design, SDC, startup, and operator training) [a]	6,462,000
Permitting	104,000

Table A-5 (continued)
Summary of estimated chemical precipitation treatment system capital costs for a 300 gallon-per-minute system

Cost Element	Chemical Precipitation Treatment ($)
Total Estimated Capital Cost ($M)	39
Total Estimated Capital Cost ($M) +50%	59
Total Estimated Capital Cost ($M) –30%	27

HVAC = heating, ventilation, and air conditioning
I&C = instrumentation and controls
M = million
MCC = motor control center
SDC = services during construction
[a] See Table A-4 for factors used to estimate these additional cost items.
[b] Pre-engineered building was estimated at 15,000 and 20,000 square feet (includes two floors) for 300 gpm and 600 gpm alternatives, respectively. Building was assumed to accommodate an office, motor control center (MCC), chemicals storage and dewatering equipment.
[c] Assumes wastewater tie-in piping of 2,000 linear feet installed above ground
[d] Includes fencing, grading, roads, sidewalks, and similar items. gpm = gallons per minute

A.1.8.2 Operations and maintenance costs and quantities

The total estimated O&M costs for chemical precipitation treatment for a 300-gpm chemical precipitation treatment system with 1 percent solids are provided in Table A-6.

Table A-6
Summary of chemical precipitation treatment annual operations and maintenance costs for a 300-gallons-per-minute system

Cost Element	Quantity	Cost [a] ($ per year)	Assumptions
Electricity (megawatt hours per year) [a]	538	28,000	$0.0523 per kilowatt-hour
Residuals (dry tons per year) [a]	3,333	180,000	$54 per dry ton. All wastes are assumed to be RCRA nonhazardous solids.
Maintenance	-	193,000	3.0% of total installed equipment cost
Major chemicals [b]			
Hydrated lime (tons per year)	1,300	182,000	Hydrated lime: $0.09 per pound
Ferric chloride (35%) (gallons per year)	11,300	22,000	Ferric chloride (35%): $1.94 per gallon
Hydrochloric acid (30%) (gallons per year)	26,500	18,000	Hydrochloric acid (30%): $0.68 per gallon
Polymer (pounds per year)	2,700	5,000	Polymer: $1.86 per pound
Organosulfide (gallons per year)	770	9,000	Organosulfide: $11.71 per gallon

Table A-6 (continued)
Summary of chemical precipitation treatment annual operations and maintenance costs for a 300-gallons-per-minute system

Cost Element	Quantity	Cost [a] ($ per year)	Assumptions
Labor (full-time equivalents)			
Operators	4	409,000	$49 per hour for operator
Dewatering	1	102,000	$49 per hour for operator
Supervisor	1	158,000	$76 per hour for supervisor
Compliance	-	74,000	
Total Estimated O&M Cost ($M per year)		**1.4**	

M = million
O&M = operations and maintenance
RCRA = Resource Conservation and Recovery Act
$ = U.S. dollars (June 2018)
[a] Plant is on-line 51 percent of the time; factor applied to energy, chemicals, and residuals
[b] Chemical costs are industry average and include an assumed national average freight. Chemical costs will vary depending on plant location and local chemical distributors.

A.1.8.3 Annualized costs

Capital cost estimates (Table A-5) and O&M cost estimates (Table A-6) were used to calculate total annualized costs for chemical precipitation treatment. Capital costs were annualized assuming an equipment lifetime of 20 years and 7 percent interest rate. As an example, using these values, the annualized cost for a 300-gpm 2x100 percent redundancy system is $5.1 million per year.

A.1.9 Industry cost extrapolation

Costs were estimated for the current industry. EPRI used EPA's list of 70 plants with FGD flows [ERG, 2019a] for the industry extrapolation.

The following additional assumptions were made to estimate the cost of chemical precipitation treatment to the industry:

- Of the 70 plants identified for the industry extrapolation, plants that have chemical precipitation treatment or more advanced FGD wastewater treatment already installed in their facility were not included in the cost calculation. EPA identified 40 plants that have existing full or partial chemical precipitation systems; of those, 17 plants have full chemical precipitation systems or more advanced FGD wastewater treatment. This evaluation assumed that those 17 plants would continue to use their existing treatment systems for settling and removal of FGD purge solids, so costs were not included for these systems.
- If a facility has a pond, it was assumed that the pond would be replaced by a chemical precipitation treatment system shown in Figure A-1. A total of 28 plants have FGD ponds

as their only FGD wastewater treatment. The cost of pond closure was not included in this estimate.

- If a facility has a treatment system that does not include one of the components shown in Figure A-1 (for example, metals removal using organosulfide, media filter) only the cost of adding this equipment was included in the cost to the industry. Equipment required to achieve Best Available Technology Economically Achievable (BAT) for each plant was determined using Flue Gas Desulfurization Chemical Precipitation (CP) Cost Methodology – DCN SE07093 and Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule – DCN SE07207 [ERG, 2019b; ERG, 2019c]. A total of 23 facilities did not have one or more subsystems shown in Figure A-1.
- EPRI's list accounts for retirements of R. D. Morrow (ID 1185) and Units 1 and 2 of Chesterfield Power Station (ID 4679) as of the end of 2018. EPRI's list also does not include Lewis & Clark (ID 394) which is at the 50-MW limit.
- The total cost for the industry was estimated assuming that industry plants with a reported capacity factor greater than 60 percent (26 percent of industry plants) would install a 2x100 percent redundancy system. The remaining plants with reported lower capacity factors (74 percent of industry plants) would install a 2x60 percent redundancy system. This is based on net generation rates from 2017.

The conceptual design costs, such as those presented in Tables A-5 and A-6, were used to estimate costs for the plants described above. Capital, O&M, and annualized costs were calculated for each of the 69 plants (the list of 70 plants minus the 1 retirement), using cost estimating curves based on each plant's FGD flow rate and solids loading.

Table A-7 summarizes chemical precipitation treatment costs to the current industry.

Table A-7
Chemical precipitation treatment costs to industry for FGD wastewater

Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Annualized Cost [a] ($M per year)
1,652	46	202

M = million
$ = U.S. dollars (June 2018)
Costs represent EPA's list of 70 plants with FGD flows [ERG, 2019a].
[a] Annualized cost based on 20-year equipment life and 7% interest rate.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 21

Comment Excerpt:

3. EPA has underestimated chemical precipitation equipment redundancy.

EPA appears to have underestimated the equipment redundancy needed for chemical precipitation systems. Certain plants in the Southern Company system have used in its design a 2x100% redundancy system for chemical precipitation of FGD wastewater. From an industry perspective, EPRI has stated that redundancy is best represented by a range of system redundancies; therefore, EPRI has assumed that plants with a reported capacity factor greater than 60% would install a 2x100% redundancy and that the remaining plants with reported lower capacity factors would install a 2x60% redundancy system.[32] Southern Company agrees with EPRI's approach that equipment redundancy is based on "different utility operational strategies" as well as capacity factor.[33] Southern Company urges EPA to revisit its approach on chemical precipitation equipment redundancy to more accurately estimate the cost of FGD wastewater treatment.

32 See Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 2-7 to 2-8.
33 Id. at 2-8.

Commenter Name: Major L. Clark, III and David Rostker
Commenter Affiliation: Office of Advocacy, U. S. Small Business Administration
Document Control Number: EPA-HQ-OW-2009-0819-8310-A1
Comment Excerpt Number: 5

Comment Excerpt:

[In particular, EPA should be closely examining the TWPE metric for the following requirements.]

...

- **Chemical Precipitation:** EPA proposes to require chemical precipitation (CP) to treat wastewater from flue gas desulphurization (FGD), an air emissions control device, for units below the low-utilization threshold. For some units, including several operated by small coops or small municipalities, this requirement is very expensive for the environmental benefit it accrues. EPA should reconsider the requirement for CP or consider alternative criteria to ensure that it is required only where cost-effective.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 13

Comment Excerpt:

For so-called "high flow" facilities, EPA is embracing as BAT chemical precipitation alone, which it rejected in both the 2015 Rule and in this rulemaking for every single plant except one.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 66

Comment Excerpt:

b. EPA Proposes a BAT It Previously Rejected as Inadequate.

EPA unlawfully proposes a BAT that it previously rejected as inadequate. EPA proposes chemical precipitation alone as BAT for high FGD flow facilities.[231] But in 2015, EPA rejected chemical precipitation as BAT. The agency found chemical precipitation was "not effective at removing selenium, nitrogen compounds, and certain metals that contribute to high concentrations of TDS in FGD wastewater."[232] Discharging those pollutants "caus[es] adverse human health impacts and some of the most egregious environmental impacts."[233] EPA therefore "determined that, by itself, chemical precipitation would not result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants (see CWA section 301(b)(2)(A)), and rejected that technology basis as BAT."[234]

In the 2019 Proposal, EPA does not explain or acknowledge important inconsistencies created by its policy reversal: How can a technology EPA once rejected as inadequate become the best available technology more than four years later? Does EPA still expect human health impacts and egregious environmental impacts from pollutants discharged in wastewater treated only by chemical precipitation? Most importantly, does chemical precipitation alone result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants? EPA's proposed rule is arbitrary and capricious because it fails to explain or even acknowledge these critical inconsistencies. Instead, EPA relies solely on cost to explain its proposal.

[231] 84 Fed. Reg. at 64,638.
[232] 80 Fed. Reg. at 67,851.
[233] Id.
[234] Id. at 67,852.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 74

Comment Excerpt:

e. EPA Paradoxically Endorses and Rejects the Same Technology as BAT

Setting chemical precipitation as BAT, despite rejecting it elsewhere as inadequate, is arbitrary and capricious. In 2015, EPA found that chemical precipitation would not result in reasonable further progress.[261] Consistent with that finding, EPA's current proposal rejects the chemical precipitation as BAT for the FGD wastewater category, partly because chemical precipitation inadequately reduces discharges of pollutants, including selenium and nitrate/nitrite.[262] EPA's "paradoxical action"—selecting chemical precipitation as BAT, while rejecting it as inadequate elsewhere—"signals arbitrary and capricious agency action."[263] Further, "EPA has contravened the plain language of the CWA, which defines BAT as the technology that '*will result* in reasonable further progress' toward pollutant discharge elimination."[264]

[261] 80 Fed. Reg. at 67,852.
[262] 84 Fed. Reg. at 64,632.
[263] *Sw. Elec. Power Co.*, 920 F.3d at 1016.
[264] Id. (emphasis original).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 46

Comment Excerpt:

Instead of proposing a zero-discharge technology, which is available and achievable, as BAT for FGD wastewater, EPA unlawfully proposes to reconsider and *weaken* the technology requirements for FGD wastewater discharges. As an initial matter, EPA inexplicably includes chemical precipitation alone as a potential BAT option – Option 1 – even though EPA itself has already concluded that the technology, by itself, is *not* effective in reducing toxic selenium or nitrate pollution. As explained below, there is no valid basis for EPA to revisit that finding.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 48

Comment Excerpt:

A. EPA Cannot Lawfully Adopt Chemical Precipitation, By Itself, As BAT.

Under proposed Option 1, EPA would find chemical precipitation alone is BAT for FGD wastewater. The record makes clear, however, that chemical precipitation, by itself, cannot be BAT. BAT-based numeric effluent limits "shall require the *elimination* of discharges of all pollutants if the Administrator finds, on the basis of information available to him . . . that such elimination is technologically and economically achievable."[171]

Here, going back to the 2013 ELG proposed rule, EPA has consistently found that chemical precipitation alone "is not effective at removing many of the pollutants of concern in FGD wastewater, including selenium, nitrogen compounds, and certain metals that contribute to high concentrations of total dissolved solids in FGD wastewater (e.g., bromides, boron)."[172] Selenium is acutely toxic to humans and aquatic organisms,[173] and nitrates in drinking water are especially dangerous for children.[174] EPA concedes that chemical precipitation does nothing to address either of these pollutants. Conversely, and as EPA concedes, chemical precipitation followed by biological treatment achieves substantial reductions in discharges of toxic mercury and arsenic – through the chemical precipitation process – and reductions in selenium and nitrate/nitrate levels through the biological treatment system. And for the pollutants that chemical precipitation does treat, adding biological treatment will "remove approximately 90 percent of the mercury remaining in the effluent from chemical precipitation" alone.[175] Moreover, there is no dispute that "[b]oth chemical precipitation and biological treatment are well demonstrated technologies that are available to steam electric facilities for use in treating FGD wastewater."[176]

In sum, both the 2015 ELG Rule and the 2019 Proposal recognize that chemical precipitation *plus* biological treatment is achievable, available, and would substantially reduce levels of mercury, arsenic, selenium, and nitrates relative to chemical precipitation alone. It is not clear why EPA even included chemical precipitation alone as an option. Indeed, the agency itself states that it is not proposing to revisit its findings with respect to the availability and achievability of chemical precipitation plus some form of biological treatment.[177] Having concluded that chemical precipitation is not effective in removing harmful pollutants from FGD wastewater, and that the addition of biological treatment significantly reduces harmful mercury, arsenic, selenium, and nitrates, any final rule selecting chemical precipitation alone as BAT would be arbitrary and unlawful.[178]

[171] 33 U.S.C. § 1311(b)(2)(A) (emphasis added); see also *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980) (holding that BAT limits "represent[] a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges.").
[172] 78 Fed. Reg. 34,432, 34,473 (June 7, 2013).
[173] EPA, Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Docket ID No. EPA-HQ-OW-2009-0819-6427, at 3-5-3-6; 3-24-3-26 (Sept. 2015) ("2015 EA").
[174] See EPA, Basic Information about Nitrate in Drinking Water, http://water.epa.gov/drink/contaminants/basicinformation/nitrate.cfm (visited Sept. 20, 2013).
[175] 84 Fed. Reg. at 64,632; see also 78 Fed. Reg. at 34,473.
[176] 84 Fed. Reg. at 64,631. EPA identifies at least fifteen steam electric facilities with wet scrubbers – or, 11 percent of all steam electric facilities – that have both chemical precipitation and some form of biological treatment in place, and are capable of meeting EPA's proposed numeric limitations for FGD wastewater. Of these fifteen facilities, nine are currently operating anoxic/anaerobic biological treatment designed to substantially reduce nitrogen compounds and selenium in their FGD wastewater. Id.
[177] 84 Fed. Reg. at 64,631.
[178] *Sw. Elec. Power Co.*, 920 F.3d at 1016, 1019 (holding that EPA acted arbitrarily unlawfully by selecting as BAT a technology that the agency itself concluded was ineffective and inferior and "would not achieve 'reasonable further progress' toward eliminating pollution from those streams").

Commenter Name: Regina Rodriguez, Ph.D.
Commenter Affiliation: Carbonxt

Document Control Number: EPA-HQ-OW-2009-0819-8490-A1
Comment Excerpt Number: 3

Comment Excerpt:

As noted by the EPA, chemical precipitation followed by low residence time biological reactors are the proposed technology best available technology for the treatment of wet flue gas desulfurization (WFGD) wastewater. While these technologies are proven and effective, difficulties with such chemical precipitation methods include: delicate water chemistry characteristics that may lead to “reemission” events in which mercury is released from the aqueous chemical bond and released out with the flue gas. Chemical precipitation methods are also slow in their response times and often take hours or longer for their effects to be witnessed, causing some utilities to risk their compliance.

Chemical precipitation often also relies on the use of coal treatments of halogens (bromine, iodine, and chlorine) to oxidize mercury into the liquid phase of the WFGD slurry. These halogens accumulate in the WFGD slurry and can be emitted in high concentrations along with the wastewater discharges. These halogens which are emitted in the effluent can pollute water systems and potentially cause toxic disinfection by-products if the water is treated through a municipal water treatment facility further downstream. The formation of disinfection by-products are beyond the scope of this comment, however it should be understood that many systems using chemical precipitation, may also require the use of halogens (which in turn may lead to disinfection by-products).

15 FGD Wastewater – CP + LRTR and CP + HRTR

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 14

Comment Excerpt:

FGD WASTEWATER BAT TREATMENT COSTS

2.1 **EPA underestimated the capital cost of FGD BAT (chemical precipitation plus low residence time reduction biological treatment) for the industry. EPRI’s annualized cost estimate is approximately 70 percent higher than EPA’s estimate.**

EPRI compared EPA’s cost estimates for chemical precipitation (CP) and low residence time reduction (LRTR) biological treatment (biological) published in *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option* – DCN SE07090, Table 4 (FGD CP Only) and *Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology*,

Appendix 3 (FGD CP + Biological) [ERG, 2019b; 2019d] with its own estimate of the cost to comply with the ELG rule. EPRI updated industry profiles, reflecting changes announced as of October 2018, to match EPA's industry portfolio, as documented in *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule –* DCN SE07207 and *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option* – DCN SE07090, [ERG, 2019a; 2019b] (unless otherwise noted). These updates included new units, new wet FGD systems, coal unit retirements and fuel conversions, and modifications to wet FGD treatment and bottom ash systems. Therefore, the list of units for which EPRI is providing capital and O&M costs is very similar to the list of units EPA has used. Table 2-1 below compares EPA and EPRI chemical precipitation and biological costs.

Table 2-1
Chemical precipitation and biological cost comparison for the industry

	Source of Industry Cost	Capital Cost ($M)	Ratio of EPRI to EPA Capital Cost	Annual O&M Cost ($M/yr)	Total Annualized Cost ($M/yr) @7%	Ratio of EPRI to EPA Annualized Cost
Option 1 (CP Only)	EPA	$675		$42	$105	
	EPRI	$1,652	2.4	$46	$202	1.9
Option 2 (CP + Biological)	EPA	$1,127		$76	$181	
	EPRI	$2,495	2.2	$79	$314	1.7
Incremental Biological *	EPA	$452		$33	$76	
	EPRI	$843	1.4	$27	$107	1.4

Biological = Low Residence Time Reduction (LRTR) biological treatment
CP = Chemical precipitation stand-alone treatment
M = million
O&M = Operations and maintenance
$ = U.S. dollars, pre-tax in 2018 dollars
Assume 7% interest rate and 20-year life for annualized cost
* EPA's incremental biological costs were calculated by subtracting CP standalone costs for Regulatory Option 1 from ERG's *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090* from CP + Biological costs from Appendix 3 of ERG's *Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology*. This does not account for cost differences between EPA's CP stand-alone costs and EPA's CP pretreatment costs.

As one can see from Table 2-1, the factors by which EPRI's estimates exceed EPA's estimate are significant, more so for capital cost estimates that range from 86 percent higher to 144 percent 2-2 higher. The major differences between estimates made by EPA and EPRI include the following, each of which is discussed in more detail in the subsections below:

1. EPA appears to have underestimated the peak FGD wastewater design flow used to size equipment.
2. EPA appears to have underestimated the cost factors used to calculate total installed costs from vendor estimates [EPA, 2019a]. Standard industry practice for developing budgetary cost estimates uses cost factors that are more typical of an engineering estimate; these engineering cost factors should be used.
3. EPA underestimated FGD chemical precipitation equipment redundancy that would be required on this critical equipment.
4. Costs appears to be underestimated at plants with high-salinity FGD water.

The impact of the differences in cost factors used to calculate total installed costs can be seen in Table 2-2, in which we have normalized EPRI and EPA's estimating to assume the same design flow rate of 300 gpm and the same redundancy of 2x60% for FGD chemical precipitation.

Table 2-2
Chemical precipitation and biological cost comparison for a case study plant designed for 300 gpm flow

	EPA	EPRI	EPA	EPRI	EPA	EPRI
	CP Pretreatment, 2x60% redundancy		Incremental Biological		CP + Biological	
Capital Cost ($M)	23	34	9	13	32	47
Annualized Capital Cost ($M/yr) @7%	22	3.2	0.9	1.2	3.0	4.5
Factor of EPRI to EPA Capital Cost		1.5		1.4		1.5

Biological = Low Residence Time Reduction (LRTR) biological treatment. For EPA's cost, EPRI used high-nitrate (the more expensive of the two options). For purposes of this comparison, the EPRI cost also includes nitrate pretreatment.
CP = Chemical precipitation treatment. For EPA's cost, EPRI used offsite transport/disposal of solids. For a 300-gpm case study plant, offsite transport/disposal of solids is about 1 percent more expensive than onsite transport/disposal, so it was selected to show that—even using the more expensive of EPA's two options—EPRI's costs are higher than EPA's.
gpm = gallons per minute
M = million
$ = U.S. dollars, pre-tax in 2018 dollars
Assume 7% interest rate and 20-year life for annualized cost.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 16

Comment Excerpt:

2.3 **EPA appears to have underestimated the cost factors it used to create a cost estimate for each individual plant. Cost factors more typical of an industry standard engineering estimate are more appropriate.**

EPA should clarify their detailed, bottoms-up estimating methodology for costs other than those for major equipment from vendors. While insights are available in Table 1 of the ERG 2019 memorandum *Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology* [ERG, 2019d], the scope of what ERG refers to as the “Missing Capital Cost” is not presented in the ERG memo. The ratio of the total LRTR capital cost to the vendor 2-4 equipment cost used by EPA is roughly 1.6, as shown in Table 2-3. When EPRI evaluated what is included in the vendor’s cost, and applied standard engineering practice cost estimating [AACE, 2011b] to compute total installed cost, the ratio was roughly 2.5 times, as shown in Table 2-4. A detailed breakdown of what EPRI included is presented in Appendix B of these comments.

Table 2-3
EPA's estimated LRTR total capital costs for low-nitrate and high-nitrate systems [ERG, 2019d]

FGD Flow (GPD)	Updated Vendor Capital Cost (2018$)	Missing Capital Cost (2018$)	Building Capital Cost (2018$)	Transportation & Disposal Capital Cost (2018$)	Updated Total LRTR Capital Cost (2018$)	*Calculated Ratio of Total LRTR Capital Cost to Vendor Capital Cost*
Low Nitrates						
144,000	$2,840,000	$1,560,000	$270,000	$23,400	$4,700,000	*1.7*
432,000	$4,020,000	$2,210,000	$300,000	$32,700	$6,560,000	*1.6*
864,000	$5,690,000	$3,130,000	$300,000	$45,600	$9,160,000	*1.6*
1,728,000	$8,140,000	$4,480,000	$330,000	$64,700	$13,000,000	*1.6*
High Nitrates						
144,000	$3,430,000	$1,890,000	$270,000	$28,000	$5,620,000	*1.6*
432,000	$4,810,000	$2,640,000	$300,000	$38,700	$7,790,000	*1.6*
864,000	$6,770,000	$3,720,000	$300,000	$53,900	$10,800,000	*1.6*
1,728,000	$9,710,000	$5,340,000	$330,000	$76,900	$15,500,000	*1.6*

GPD = gallons per day
LRTR = low residence time reduction

Table 2-4
EPRI's estimated LRTR total capital costs for a 300-gpm high-nitrate system (from Table B-5 and Table B-6 of Appendix B)

FGD Flow (GPD)	Updated Vendor Capital Cost (2018$)	Updated Total LRTR Capital Cost (2018$)*	*Calculated Ratio of Total LRTR Capital Cost to Vendor Capital Cost*
432,000	$5,280,000	$13,060,000	*2.5*

GPD = gallons per day
LRTR = low residence time reduction
* = Detailed breakdown of what EPRI included to calculate total cost is presented in Appendix B of these comments

The factors provided in Table 2-5 reflect industry standard practice and should be used to calculate the total estimated cost of a biological treatment system. EPRI applied these factors to the total purchased equipment cost to calculate a total estimated cost for a biological treatment system. The values used are based on industry experience [CH2M, 2009; AACE, 2011b] and standard engineering practice for all industrial sectors. These factors were used by EPRI to calculate a total estimated cost for each of the plants included in the calculation of industry cost. By excluding or underestimating these items, it appears that EPA has underestimated the cost of treatment systems for each facility and accordingly, overall industry costs.

EPA may have underestimated the additional costs for site work contractor profit, etc., needed to estimate total installed cost of biological treatment. Table 2-5 provides a summary of cost factors that EPRI applied to each facility to develop its cost estimate for biological selenium treatment. EPRI applied different cost factors to the "non-SeHAWK system costs" which include an inline selenium monitor and chemical addition for ORP control. An inline monitor for selenium will be required to optimize process control and to reduce the likelihood of permit violations because turnaround times from offsite laboratories (utility and commercial) will be too long (i.e., several days) to be used for treatment process control. However, the technical feasibility of inline selenium monitors has not been demonstrated, and their cost impacts are uncertain.

Table 2-5
Biological treatment cost factors in EPRI estimate for Frontier SeHAWK® system

Additional Cost Items	Value Used (%)	Rationale for Selected Value
Cost Factors Applied to SeHAWK® System Cost		
Site work	3	Assumes SeHAWK® system will be co-located with physical/chemical treatment plant. Site will be made "pad ready" as required by Frontier.
Concrete	–	Concrete for the SeHAWK® system is included in Frontier cost.
Piping	5	Lower than range. Frontier's costing includes piping skids, and piping interior to bioreactors, but not costing for field-installed piping, which would run to and from the SeHAWK® system and also between stage 1 and stage 2 bioreactors.
Miscellaneous metals, finishes	–	Frontier cost curve provides miscellaneous metals costs for items within the SeHAWK® system. Items outside the SeHAWK® system are covered by tie-in allowance.
Mechanical, heating/ventilation/air conditioning	–	Not included
Electrical	5	Lower than industry's typical range. Frontier's electrical estimates include rotating equipment and instrumentation required for process equipment, with electrical consumption weighted by duty type (continuous vs. intermittent). Capital electrical costs not in Frontier's scope include items such as motor control centers and disconnects for motors, plant air supply, as well as installation of field wiring.
Instrumentation and control	–	I&C for SeHAWK® system is included in Frontier cost.
Tie-in/Integration	10	Includes items such as integrating SeHAWK® controls into plant DCS and SCADA; pipe interconnections; and extending power, control wires, and piping to the SeHAWK® system.
General contractor general conditions	5	Used lower number than typical because majority of equipment is SeHAWK® system.

Table 2-4 (continued)
Biological treatment cost factors in EPRI estimate

Additional Cost Items	Value Used (%)	Rationale for Selected Value
Cost Factors Applied to SeHAWK® System Cost		
General contractor profit	12	Used lower number, as majority of equipment is SeHAWK® system.
Miscellaneous unidentified cost	20	Contingency of 20 percent is consistent with a Class 4 estimate.
Engineering (design, services during construction, startup, and operator training)	–	Engineering for the SeHAWK® system is included in Frontier cost.
Client administrative and overhead	7	Higher than range, assumes it also includes early engineering and geotechnical investigation.
Cost Factors Applied to All Non-SeHAWK® System Costs [1]		
Site work	4	Mid-point of range.
Concrete	–	Concrete for non- SeHAWK® system costs is included in the equipment cost.
Piping	25	Higher than range, assumes installation of high-grade alloy.
Miscellaneous metals, finishes	15	High-point of range.
Mechanical, heating/ventilation/air conditioning (HVAC)	7.5	Mid-point of range.
Electrical (process electrical and site electrical)	22	Mid-point of range.
Instrumentation and control	15	Mid-point of range.
Tie-in/Integration	5	This includes items such as integrating system controls into the plant DCS and SCADA; pipe interconnections; and extending power, control wires, and piping to system.
General contractor general conditions	12.5	Mid-point of range.
Bonding and insurance	2.85	Mid-point of range.
General contractor profit	14.25	Mid-point of range.
Miscellaneous unidentified cost	20	Mid-point of range.

Table 2-4 (continued)
Biological treatment cost factors in EPRI estimate

Additional Cost Items	Value Used (%)	Rationale for Selected Value
Cost Factors Applied to All Non-SeHAWK® System Costs [1]		
Engineering (design, services during construction, startup, and operator training)	20	Mid-point of range.
Client administrative and overhead	7	Higher than range, assumes it also includes early engineering and geotechnical investigation.

DCS = distributed control system
HVAC = heating, ventilation, and air conditioning
I&C = instrumentation and control
SCADA = supervisory control and data acquisition
Frontier SeHAWK® is described in [ERG 2019d, Appendix B]
[1] Non-SeHAWK® System Costs include selenium monitor (all plants) and chemical addition system for oxidation reduction potential (ORP) control (some plants).

EPRI has reviewed the non-confidential business information (non-CBI) supplied in the public docket [EPA, 2019a]. EPRI generally agrees with the purchased equipment costs for treatment systems treating a range of wastewater flow rates. EPRI has taken a similar approach by obtaining vendor quotations for various flow rates for each major piece of equipment in order to develop cost curves. Using these cost curves, EPRI has generated a cost model for chemical precipitation treatment and biological treatment equipment similar to the model EPA created and described in *Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* [EPA, 2013]. The methodology EPRI used to create this cost model is described further in Appendix A (Chemical Precipitation) and Appendix B (Biological) of these comments.

According to the Association for the Advancement of Cost Engineering International (AACE) guidance, cost models based on definitive cost estimates and standard design information can be used for various facility or plant costs at the planning stage, and are often used for conceptual cost estimating [AACE International, 2011a], for Class 5 or Class 4 estimates. (See Table A-3 in Appendix A for additional information). Costs developed from these curves are then generally factored to determine the overall capital cost of a project early in the conceptual planning phase [AACE International, 2011b].

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 18

Comment Excerpt:

2.5 **EPA appears to have underestimated cost at plants with high-TDS FGD water.**

Higher-salinity water, and swings in FGD water salinity which can occur due to FGD system operational variability and variability can cause operational challenges in biological treatment. Frontier states they have demonstrated, "... successful treatment of a broad range of FGD water chemistries, with TDS averaging 17,556 mg/L (36,000 mg/L maximum) and chloride averaging 7,000 mg/L (17,200 mg/L maximum)" [ERG, 2019d]. However, in a recent EPRI pilot test with FGD wastewater of approximately 35,000 milligrams per liter (mg/L) total dissolved solids (TDS) by another leading biological treatment vendor (Suez), the vendor needed to dilute influent to below 20,000 mg/L TDS [EPRI, 2018]. Such blending to lower TDS increases the cost of treatment as it increases flow rate and would likely reduce the ELG limits due to the combined waste formula. EPRI assumed three percent of plants would require mixing with lower-salinity water, which increased industry cost by 0.2 percent.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 19

Comment Excerpt:

2.6 **EPA's bioreactor costs appear to be underestimated because they were provided by the vendor based on achieving higher selenium limits.**

Frontier provided the EPA with a cost estimate for its supplied equipment in an LRTR system that, "... is designed to meet the specified water quality parameters of 50 micrograms per liter (µg/L) selenium, 356/788 nanograms per liter (ng/L) mercury, 8/11 ng/L arsenic, and 4.4/17 mg/L Nitrate-N ..." [ERG, 2019d]. The proposed 2019 ELG limits are set with a lower monthly average limit for selenium (as well as mercury and nitrate-N) [EPA, 2019b]. This may require the bioreactor supplier to provide more residence time to reach the lower monthly average ELG for selenium by providing a larger bioreactor (at higher cost). EPA should document what impact, if any, the actual proposed BAT limits would have on the cost of an LRTR system.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 20

Comment Excerpt:

2.7 **EPA's bioreactor costs appear to be underestimated because they were provided by the vendor based on achieving higher selenium limits.**

Frontier provided EPA with a cost estimate for its supplied equipment in an LRTR system in September 2019 [ERG, 2019c]. This replaced their estimated costs provided to EPA in May 2018. The September 2019 cost estimate was significantly lower than the 2018 estimate. The price reductions differed with flow rate, ranging from nearly 30 percent at low flows (100 to 300 gpm) to nearly 50 percent at high flows (1,200 gpm). It is noted that this updated pricing is very new.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 64

Comment Excerpt:

B —APPENDIX: FGD WASTEWATER TREATMENT COST METHODOLOGY—BIOLOGICAL

B.1 Cost estimating summary for biological treatment of flue gas desulfurization wastewater using Frontier Water System's SeHAWK®

B.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the cost of biological treatment of flue gas desulfurization (FGD) wastewater to the steam electric industry, based on EPA's industry profile [ERG, 2019a], using Frontier's Biological Metals Removal (SeHAWK®) system. This technical memorandum describes the method for calculation of costs of biological treatment for an individual plant, the assumptions associated with the cost calculations, and the estimated costs for biological treatment to the steam electric industry. Table B-1 outlines the cost to the current industry for the cost of biological treatment (excluding required chemical precipitation pretreatment), and the total cost of biological treatment for the industry including required chemical precipitation pretreatment.

Table B-1
Biological treatment costs to industry for FGD wastewater, in June 2018 dollars

Industry	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Annualized Cost [a] ($M per year)
Incremental biological cost for SeHAWK	843	33	113
Biological treatment cost including physical/chemical pretreatment	2,495	79	314

M = million
$ = U.S. dollars (June 2018)
Costs represent EPA's 2019 plant list [ERG, 2019], adjusted to account for retirements of R. D. Morrow (ID 1185) and Units 1 and 2 of Chesterfield Power Station (ID 4679) as of the end of 2018. EPRI's list also does not include Lewis & Clark (ID 394) which is at the 50-MW limit.
[a] Annualized cost based on 20-year equipment life and 7% interest rate.

EPRI used the cost curves supplied by Frontier to EPA in September 2019 [ERG, 2019].

B.1.2 Introduction

The U.S. Environmental Protection Agency (EPA) updated the Steam Electric Power Generating effluent limitation guidelines (ELGs) through a comprehensive information collection request (ICR) and sampling at FGD wastewater treatment systems. Following the ICR, the EPA published a draft ELG rule in 2013. EPRI previously provided estimated costs for FGD wastewater treatment technologies as a part of comments during the 2013 ELG rulemaking. The ELG rule was later finalized in 2015 but is now being reconsidered for FGD wastewater. Therefore, EPRI has prepared updated cost estimates of FGD wastewater treatment technologies for commenting on the revised draft ELG rule. The treatment technologies evaluated were (1) chemical precipitation, (2) biological, (3) chemical softening followed by vapor-compression evaporation/ crystallization (CS + VCE/CRX), (4) chemical precipitation followed by vaporcompression evaporation and brine solidification (CP+VCE/BS), (5) chemical softening followed by seawater reverse osmosis (SWRO) and brine solidification (CS + SWRO/BS), and (6) chemical precipitation followed by advanced membrane filtration (AMF) and brine solidification (CP+AMF/BS). The technologies are discussed in separate Appendices A thru D, with Appendix B addressing biological treatment. The cost evaluation results for chemical precipitation, biological and CS + VCE/CRX treatment were extrapolated industry-wide.

B.1.3 Biological treatment overview and EPRI assumptions

The biological treatment system used to evaluate costs for the industry consists of a Biological Metals Removal (SeHAWK®) system. The treatment train for the SeHAWK® system consists of a two-stage system using an upflow, fluidized bed reactor followed by a downflow media bed. In a fluidized bed reactor, water is passed through a granular solid media at a high enough velocity to suspend, or fluidize, the media, creating a reactor configuration for attached growth. The two-stage system allows for a smaller footprint and comes in a modularized configuration to reduce installation costs. A backwash water supply tank is also provided. It is assumed that backwashed solids are handled and dewatered as part of an upstream physical/chemical treatment process, so the cost for dewatering equipment is not included in the incremental cost estimate for biological treatment. Microbial growth is supported by nutrients added through feed water, and by an additional substrate in case the feed water does not have sufficient amounts or kinds of nutrients, which is typically required for FGD wastewater. A heat exchanger is also included to cool the FGD wastewater prior to entry into the SeHAWK® system.

Improved monitoring of FGD wastewater will be needed to address challenges of varying water quality [EPA, 2015]. Some of this monitoring (such as pH, suspended solids in the physical/chemical treatment, and ORP and nitrates around the bioreactor) is assumed to be included in "typical" SeHAWK® system design. In addition, EPA recommends in-plant analyzers so that plants can know if their treated effluent meets the BAT limits. To estimate costs for the industry, EPRI assumed that all plants will require an inline selenium monitor, as compared with the alternative of relying on daily grab samples shipped to an outside lab with days to weeks turn-around-time.

Oxidants can negatively impact biological systems; additionally, anoxic/anaerobic systems operate under low ORP conditions. Currently, wet FGD operators are managing the FGD absorber water chemistry and ORP to optimize sulfite oxidation to sulfate as well as gypsum quality, corrosion concerns, and mercury flue gas removal. Some plants may find that it is more cost-effective to use a chemical reductant such as sodium bisulfite to manage oxidants and the ORP in the FGD blowdown, which is a smaller water stream, rather than in the entire absorber. To estimate costs for the industry, EPRI assumed that 50 percent of plants will require sodium bisulfite addition to manage the ORP in the FGD blowdown. This is based on available data from EPRI and EPA for FGD wastewater.

Denitrification will be needed for pre-treatment of high-nitrate (greater than 50 milligrams per liter as N [mg/L-N]) FGD wastewater prior to entry into the SeHAWK® system for some plants [ERG, 2019]. Some sites may be able to minimize additional capital costs by repurposing existing equipment for denitrification pre-treatment. Other sites will be unable to repurpose existing equipment and will require additional equipment for denitrification pre-treatment. To estimate costs for the industry, EPRI assumed that additional denitrification would be needed for the 10 "high nitrate" plants identified by EPA [EPA, 2019].

Dilution will be needed for high-TDS or high-ionic strength FGD wastewater at a small subset of plants. The high ionic strength or salinity, as indicated by high TDS, in FGD wastewater is believed to adversely impact microbial health due to osmotic pressure, and thus negatively impacts selenium and nitrate reduction. Suez has determined that biological treatment can function in FGD wastewater with TDS up to 35,000 milligrams per liter (mg/L) [EPA, 2015]. To estimate costs for the industry, EPRI assumed that high-TDS wastewater would increase the size of the SeHAWK® system by 13 percent (i.e., roughly the ratio to dilute from a maximum TDS concentration of 40,000 mg/L to 35,000 mg/L) and that 3 percent of plants will have high-TDS wastewater. This is based on available data from EPRI and EPA.

Frontier's experience in piloting biological treatment of FGD wastewater suggests that membrane post-treatment (ultrafiltration) is needed after the SeHAWK® system to meet the proposed selenium limit. To estimate costs for the industry, EPRI assumed that all plants will require membrane post-treatment.

Figure B-1 shows a block flow diagram of the biological treatment process.

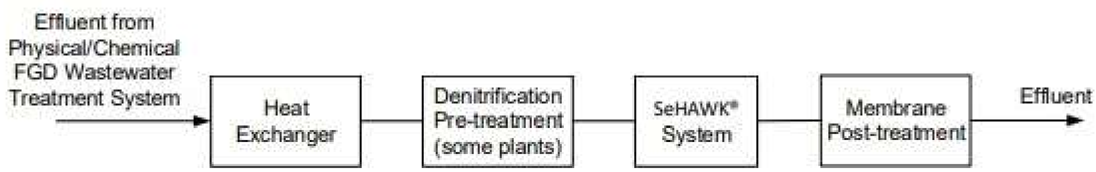

Figure B-1
SeHAWK® biological wastewater treatment system

The biological treatment system requires pretreatment achievable with a chemical precipitation FGD wastewater treatment system for all plants to reduce influent total suspended solids (TSS) to less than a value ranging from 30 to 100 mg/L. Figure B-2 shows the typical physical/chemical treatment plant that would precede the biological treatment system. The physical/chemical treatment system consists of the following unit processes: equalization, desaturation, chemical addition to enhance metals removal, clarification, neutralization, and solids dewatering. Some plants may require media filtration to be installed prior to the biological treatment system if 30 mg/L TSS cannot be achieved by clarification. However, at this time no additional costs have been included for media filtration. The assumptions regarding development of chemical precipitation treatment system costs are provided in Appendix A.1.

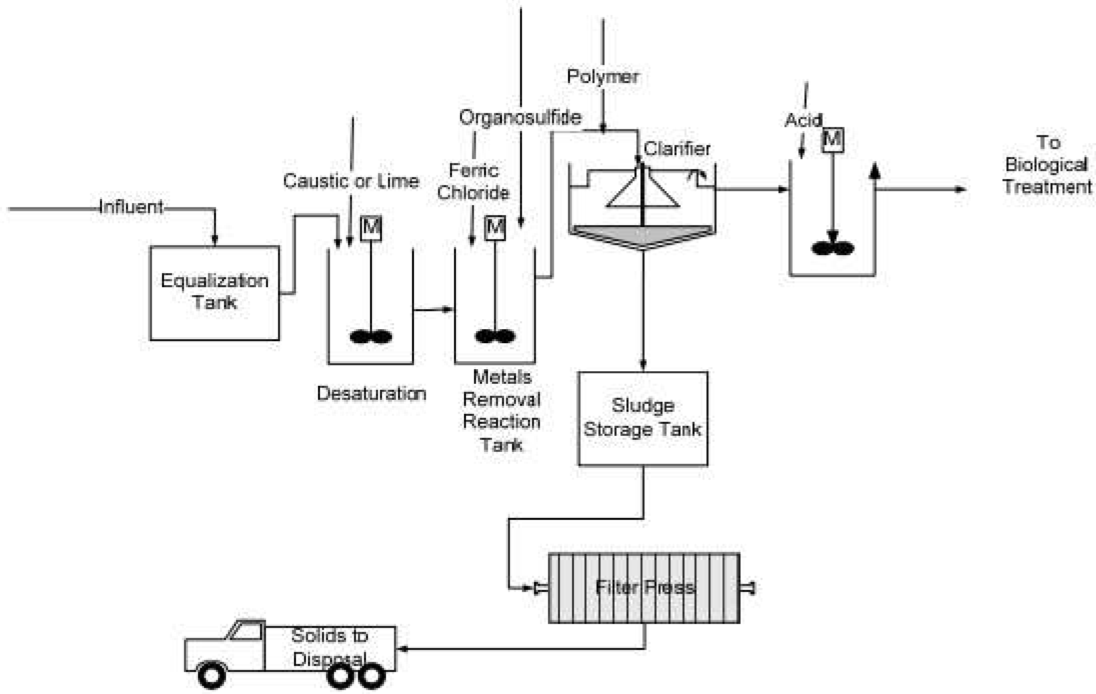

Figure B-2
Process flow diagram for chemical precipitation treatment system

B.1.4 Conceptual design basis

The design basis for the cost estimate is described in this section.

B.1.4.1 Flow rate basis

Flow rate assumptions are presented in Appendix A.1.

B.1.4.2 Feed water quality characteristics

Chemical precipitation treatment occurs before FGD solids enter the SeHAWK® system. This pretreatment reduces influent total suspended solids (TSS) to less than 30 mg/L. The temperature of the FGD wastewater chemical precipitation treatment system effluent must be less than 105 degrees Fahrenheit (°F).

B.1.4.3 Effluent water quality characteristics

Frontier designed their system to meet the specified water quality parameters of [ERG, 2019]:

- 50 µg/L selenium
- 4.4/17 mg/L nitrate
- 356/788 ng/L mercury
- 8/11 ng/L arsenic

B.1.5 Cost development methods

B.1.5.1 Equipment cost assumptions

B.1.5.1.1 SeHAWK® system

Frontier provided cost curves based on wastewater flow rate (in 2019$ US/gallons per minute [gpm]) to estimate capital costs of the SeHAWK® system. The cost curves are intended to provide a representative budgetary value only, within the constraints of the design basis specified in this memorandum. The cost curves were provided by Frontier in September 2019 and deescalated to June 2018 pricing. Many variables can dramatically influence the cost, such as geography, differences in water chemistry, effluent requirements, client equipment specifications, alternative project structure, unionized versus non-unionized labor, site geotechnical profile, and inflation. The cost curve represents average conditions across the industry.

B.1.5.1.1.1 Scope of Costs

The following equipment and components are included in the SeHAWK® system cost provided by Frontier [ERG, 2019]:

- SeHAWK® FGD two-stage bioreactors
- Bioreactor flow control skids
- Bioreactor backwash supply skids
- Feed, and backwash supply tanks
- Heat exchanger and feed water strainer skids
- Nitrate pretreatment system (for high nitrate-N condition cost curve only, >50 mg/L)
- Chemical feed skids
- Electrical equipment to include instrumentation
- Railing, stairs, and platforms
- Engineering, including electrical and structural design for equipment
- Technology licensing fees
- Company bonding/ insurance/ profit margin
- Control narrative
- Estimated freight costs of all components (assuming eastern US delivery)
- System start up and commissioning services
- Project contingency
- System start-up and operator training services
- Operation and maintenance manuals
- Ultrafiltration Polishing System with CIP

B.1.5.1.1.2 Omissions

The following items are not included in the costs provided by Frontier [ERG, 2019], and EPRI independently developed costs based on best professional judgment:

- Integration with plant DCS
- Pump MCC's
- Plant air supply
- Buildings/footings/foundations
- On site construction
- On site electrical
- Equipment offloading/ installation
- Interconnecting piping

B.1.5.1.2 Inline selenium monitor

Inline selenium monitors were not included in Frontier's cost estimates, therefore, EPRI developed cost allowances for this equipment. An inline monitor for selenium will be required to optimize process control and to reduce the likelihood of permit violations because turnaround times from offsite laboratories (utility and commercial) will be too long (i.e., several days) to be used for treatment process control. However, the technical feasibility of inline selenium monitors has not been demonstrated, and their cost impacts are uncertain. EPRI estimated that the capital cost is in the range of $102,000 per monitor.

B.1.5.1.3 Chemical addition for ORP control

EPRI developed a cost curve for the sodium bisulfite feed system as a function of FGD wastewater flow rate in gpm. The curve includes the expected cost, based on the cost of the elements that make up the chemical addition system. This equipment and the design criteria used for equipment sizing are shown in Table B-2. The curve was built by developing cost estimates for equipment at two different flow rates: 300 and 600 gpm.

Table B-2
Chemical addition for ORP control—equipment cost assumptions

Equipment	Design Criterion	Unit	Sizing
Mix Tank	Hydraulic detention time Includes concrete tank with dip tube and bridge for top-mounted mixer	Min	10
Mix Tank Mixers	Number and size of mixers based on professional judgment	hp/1,000 gal	0.1
Sodium Bisulfite Feed System	Dosage based on industry experience	mg/L (chemical/wastewater)	50

hp = horsepower
gal = gallons
mg = milligram
min = minute
L = liter

B.1.5.2 Equipment cost assumptions

B.1.5.2.1 Concrete pile foundations

Supports such as pilings and caissons are not included in the Frontier costs. EPRI estimated the cost for concrete pile foundations using the assumptions in Table B-3. To estimate costs for the industry, EPRI assumed that 88 percent of plants will require pile foundations. This is based on best professional judgement based on experience with constructed FGD wastewater systems.

Table B-3
Concrete pile foundation assumptions

Parameter	Unit	Sizing
Pile Depth	feet	80
Pile Distance C/C	feet	8
Unit Cost	$ per linear foot of piles	102

C/C = center to center

B.1.6 Capital cost assumptions

B.1.6.1 Classification of estimate

For capital cost assumptions, see Appendix A.1.6.

Considering the addition of the pre- and post-treatment equipment and lack of site-specific conditions to determine how the system will be integrated into a plant, the project definition falls within the range of a Class 4 estimate for the biological treatment alternative. These estimates were prepared to guide evaluation of the technology and are based solely on the information available at the time of the estimate. Actual final costs will depend on the actual labor and material costs, competitive market conditions, site conditions, final project scope, implementation schedule, and other variable factors.

B.1.6.2 Cost model factors

System-wide cost factors were applied to develop the cost estimate (Table B-4).

Table B-4
Model cost factors

Additional Cost Items	Typical Suggested Range (%)		Value Used (%)	Rationale for Selected Value
Cost Factors Applied to SeHAWK® System Cost				
Site work	3	5	3	Assumes SeHAWK® system will be co-located with physical/chemical treatment plant. Site will be made "pad ready" as required by Frontier.
Concrete	15	20	–	Concrete for the SeHAWK® system is included in Frontier cost.

Table B-4 (continued)
Model cost factors

Additional Cost Items	Typical Suggested Range (%)		Value Used (%)	Rationale for Selected Value
Cost Factors Applied to SeHAWK® System Cost (continued)				
Piping	6	8	5	Lower than range. Frontier's costing includes piping skids, and piping interior to bioreactors, but not costing for field-installed piping, which would run to and from the SeHAWK® system, but also between stage 1 and stage 2 bioreactors.
Miscellaneous metals, finishes	5	15	–	Frontier cost curve provides miscellaneous metals costs for items within SeHAWK® system. Items outside of SeHAWK® system are covered by tie-in allowance.
Mechanical, heating/ventilation/air conditioning	5	10	–	Not included.
Electrical	14	30	5	Lower than range. Frontier's electrical estimations include rotating equipment and instrumentation required for process equipment, with electrical consumption weighted by duty type (continuous vs. intermittent). Capital electrical costs not included in Frontier's scope would include items like MCC's and disconnects for motors, as well as installation of field wiring.
Instrumentation and control	10	20	–	Instrumentation and control for the SeHAWK® system is included in Frontier cost.
Tie-in/Integration			10	This includes items such as integrating SeHAWK® controls into the plant DCS and SCADA; pipe interconnections; and extending power, control wires, and piping to the SeHAWK® system.
General contractor general conditions	11	14	5	Used lower number as majority of equipment is SeHAWK® system.
Bonding and insurance	2.7	3	2	Frontier provides some insurance as part of its cost curve: builder's risk, commercial liability, and worker's compensation for scope of project only.
General contractor profit	14.1	14.4	12	Used lower number, as majority of equipment is SeHAWK® system.
Miscellaneous unidentified cost	10	30	20	Contingency of 20 percent is consistent with a Class 4 estimate.
Engineering (design, services during construction, start-up, and operator training)	15	25	–	Engineering for the SeHAWK® system is included in Frontier cost.

Model cost factors

Additional Cost Items	Typical Suggested Range (%)		Value Used (%)	Rationale for Selected Value
Cost Factors Applied to SeHAWK® System Cost (continued)				
Client Administrative and Overhead	3.5	3.5	7	Higher than range, assumes it also includes early engineering and geotechnical investigation.
Cost Factors Applied to All Non-SeHAWK® System Costs[1]				
Site work	3	5	4	Mid-point of range.
Concrete	15	20	–	Concrete for non- SeHAWK® system costs is included in the equipment cost.
Piping	6	8	25	Higher than range, assumes installation of high-grade alloy.
Miscellaneous metals, finishes	5	15	15	High-point of range.
Mechanical, heating/ventilation/air conditioning	5	10	7.5	Mid-point of range.
Electrical (process electrical and site electrical)	14	30	22	Mid-point of range.
Instrumentation and control	10	20	15	Mid-point of range.
Tie-in/Integration			5	This includes items such as integrating system controls into the plant DCS and SCADA; pipe interconnections; and extending power, control wires, and piping to system.
General contractor general conditions	11	14	12.5	Mid-point of range.
Bonding and insurance	2.7	3	2.85	Mid-point of range.
General contractor profit	14.1	14.4	14.25	Mid-point of range.
Miscellaneous unidentified cost	10	30	20	Mid-point of range.
Engineering (design, services during construction, start-up, and operator training)	15	25	20	Mid-point of range.
Client Administrative and Overhead	3.5	3.5	7	Higher than range, assumes it also includes early engineering and geotechnical investigation.

DCS = distributed control system
HVAC = heating, ventilation, and air conditioning
SCADA = supervisory control and data acquisition
[1] Non-SeHAWK® System Costs include selenium monitor and chemical addition system for ORP control (some plants).

B.1.6.3 Major assumptions

The following additional assumptions were made:

- Costs are presented in June 2018 dollars. Construction Cost Index values, as published by Engineering News Record (ENR), were used to escalate costs to June 2018 pricing.

- A physical/chemical wastewater treatment system will be used upstream of the biological treatment system for TSS removal and has been excluded from the estimate for incremental biological costs.
- Post-treatment after the SeHAWK® system to increase the dissolved oxygen from zero (0) to potential discharge limit of greater than 3.0 mg/L is not included.
- The biological treatment system will be co-located with the physical/chemical treatment system.
- Materials resistant to high chloride concentrations will be needed for treatment equipment.
- Installation cost estimates for non-SeHAWK® system components are based on national averages. Installed cost is provided by Frontier for the SeHAWK® system.
- Freight cost will be 4 percent of the installed equipment cost.
- No costs were included to provide cold weather protection for equipment installed outdoors (for example, heat tracing [except freeze protection for piping], insulation), installation of new utility services, new site development (for example, significant excavation), or installation in areas of limited footprint or remote locations involving delivery issues. These types of cost factors would increase cost estimates for the biological treatment system.
- Project will be sales-tax exempt.

B.1.7 Operations and maintenance costs assumptions

B.1.7.1 Cost elements

O&M requirements for this estimate include the following cost elements:

- Chemicals
- Electricity
- Residuals disposal
- Equipment maintenance
- Labor
- Compliance monitoring

B.1.7.2 Major assumptions

Costs for labor, energy, and chemicals were assumed to escalate proportionately to the Construction Cost Index values from mid-2010 to mid-2018, for an increase of approximately 3.2 percent per year. The major assumptions used in calculating these estimated O&M costs were:

- Costs are presented in June 2018 dollars. Construction Cost Index values, as published by Engineering News Record (ENR), were used to escalate costs to June 2018 pricing.
- Labor: one full-time equivalent (FTE) operator at $49/hour to account for extra labor associated with operation of the biological treatment system and, for the 10 “high nitrate” plants, an additional FTE operator at $49/hour to account for extra labor associated with operation of the denitrification pretreatment.

- All solids will be Resource Conservation and Recovery Act (RCRA) nonhazardous solids with a disposal unit cost of $54 per dry ton. The disposal cost was developed as a blended unit cost assuming that 25% of plants would use offsite landfills and 75% use onsite landfills a weighted average using onsite and offsite disposal costs provided in Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category [EPA, 2013].
- Chemical and energy costs for the SeHAWK® system were based on the estimates provided by Frontier at four different flow rates: 100, 300, 600, and 1,200 gpm.
- Chemical costs for sodium bisulfite addition were based on the cost estimates that EPRI developed at two different flow rates: 300 and 600 gpm.
- Reagents will be required to maintain the inline selenium monitor. EPRI assumed an annual cost of $3,054 in June 2018 dollars.
- Annual equipment maintenance costs will be 3 percent of the equipment costs for the facility. Equipment costs were based on the estimates provided by Frontier at four different flow rates: 100, 300, 600, and 1,200 gpm.
- It is estimated that the FGD system will operate and generate wastewater less than 100 percent of the time. Net generation rates from 2017 plus an allowance based on best professional judgement of the costs for energy, chemicals, and waste disposal to maintain the biological systems at low or no loads were used to estimate each biological treatment system's online factor.
- Compliance monitoring costs include costs for sampling and analysis of FGD wastewater effluent discharge.

B.1.8 Example cost estimate

The cost estimate for biological treatment for an example system with peak design flow rate of 300 gpm and n+1 redundancy is provided in the following subsections.

B.1.8.1 Capital costs

An example worksheet that shows the total estimated capital costs for a 300-gpm biological treatment is provided in Table B-5 (SeHAWK® System Costs) and Table B-6 (Non- SeHAWK® System Costs). The equipment costs are based on the cost curves provided by Frontier and the cost curves developed by EPRI. The construction costs shown in Table B-3 and the cost model factors shown in Table B-4 are then added to the purchased equipment cost to obtain a total estimated capital cost for the system.

Table B-5
Summary of estimated SeHAWK® system capital costs, in June 2018 dollars

Cost Element ($ thousands)	300 gpm
Frontier SeHAWK system (from high-N vendor cost curve) (De-escalated from 2019 to June 2018 Pricing)	5,283
Larger bioreactor for high salinity [a]	10
Freight (included in vendor cost curve)	0
Subtotal—Vendor Equipment Cost—Delivered	**5,292**
Pile foundations (for select plants) [b]	1,232
Subtotal—Total Equipment and Construction	**6,524**
Additional cost items	
Site work	196
Piping	326
Mechanical/HVAC (Included in vendor cost curve)	0
Electrical and I&C	326
Concrete (Included in vendor cost curve)	0
Miscellaneous metals, finishes (Included in vendor cost curve)	0
Tie-in allowance	652
Subtotal—Total Direct Costs	**8,025**
General contractor general conditions	401
Bonding and insurance	160
General contractor profit	963
Subtotal—Total Construction Cost	**9,549**
Miscellaneous unidentified cost	1,910
Engineering, services during construction, and startup (Included in vendor cost curve)	0
Subtotal	**11,459**
Client administrative and overhead	802
Total Estimated Capital Cost ($ million)	**12.3**
Total Estimated Capital Cost ($ million) +50%	**18.4**
Total Estimated Capital Cost ($ million) –25%	**8.6**

HVAC = heating, ventilation, and air conditioning
I&C = Instrumentation and controls
$ = U.S. dollars (June 2018)
[a] Since EPRI estimates that 3 percent of the industry will require larger bioreactors due to high salinity, the cost for this case study plant is just 3 percent of the total estimated cost of larger bioreactors for this plant.
[b] Since EPRI estimates that 88 percent of the industry will require pile foundations, the cost for this case study plant is just 88 percent of the total estimated cost of pile foundations for this plant.

Table B-6
Summary of estimated non-SeHAWK® system capital costs, in June 2018 dollars

Cost Element ($ thousand)	300 gpm
Heat exchanger (Included in vendor cost curve)	0
Selenium monitor	102
Chemical addition system for ORP control – Equipment [a]	40
Membrane post-treatment (Included in vendor cost curve)	0
Freight	5
Subtotal—Equipment Cost—Delivered	**146**
Chemical addition system for ORP control – Construction [a]	39
Subtotal—Total Equipment and Construction	**185**
Additional cost items	
Site work	7
Piping	46
Mechanical/HVAC	14
Electrical and I&C	69
Concrete (included in Total Equipment and Construction)	0
Miscellaneous metals, finishes	28
Tie-in allowance	9
Subtotal—Total Direct Costs	**359**
General contractor general conditions	45
Bonding and insurance	51
General contractor profit	10
Subtotal—Total Construction Cost	**465**
Miscellaneous unidentified cost	93
Engineering, services during construction, and startup	112
Subtotal	**670**
Client administrative and overhead	47
Permitting allowance	84
Total Estimated Capital Cost ($million)	**0.8**
Total Estimated Capital Cost ($million) +50%	**1.2**
Total Estimated Capital Cost ($million) –25%	**0.6**

HVAC = heating, ventilation, and air conditioning
I&C = Instrumentation and controls
$ = U.S. dollars (June 2018)
[a] Since EPRI estimates that 50 percent of the industry will require sodium bisulfite addition, the cost for this case study plant is just 50 percent of the total estimated cost of sodium bisulfite addition for this plant.

The total estimated capital cost is obtained by the sum of both the SeHAWK® (Table B-5) and non-SeHAWK® (Table B-6) costs (i.e., $12.3 million + $0.8 million = $13.1 million for a 300-gpm system).

B.1.8.2 Operations and maintenance costs and quantities

The total estimated O&M costs for biological treatment for a 300-gpm treatment system are provided in Table B-7.

Table B-7
Summary of incremental biological treatment annual O&M costs, in June 2018 dollars

Cost Element ($ thousand per year)	300 gpm	Assumptions
Energy and chemicals [a]	364	
Residuals, non-hazardous onsite landfill disposal [a]	0.9	$54 per dry ton. All wastes are assumed to be RCRA nonhazardous solids. Assume TSS = 30 mg/L; nitrate-N = 100 mg/L; influent Se = 8 mg/L
Labor for SeHAWK system	104	$49 per hour for operator
Labor for denitrification pretreatment (select plants)	104	$49 per hour for operator
Maintenance	78	3% of total installed equipment cost
Sodium bisulfite addition[1]	10	
Reagents for inline selenium monitor	3	
Compliance costs	74	
Total Estimated O&M Cost ($M per year)	**0.7**	

FTE = full time equivalent
M = million
mg/L = milligrams per liter
RCRA = Resource Conservation and Recovery Act
Se = selenium
TSS = total suspended solids
$ = U.S. dollars
[a] Plant is on-line 75 percent of the time; factor applied to energy, chemicals, and residuals

B.1.8.3 Annualized costs

Industry costs were estimated for the current industry. Assumptions used to develop the list of plants for industry extrapolation are presented in Appendix A.1.9.

The following additional assumptions were made to estimate the cost of biological treatment to the industry:

- EPRI assumed that the 10 plants designated by EPA as “high nitrate” (greater than 50 mg/LN) will require additional equipment for denitrification pre-treatment. EPRI used Frontier’s “high-N” cost data for these plants.
- EPRI assumed that 50 percent of the plant would need sodium bisulfite for ORP control.
- EPRI assumed that high-TDS wastewater would increase the size of the SeHAWK® system by 13 percent (i.e., roughly the ratio to dilute from a maximum TDS concentration of 40,000 mg/L to 35,000 mg/L) and that 3 percent of plants will have high-TDS wastewater.
- EPRI assumed that 88 percent of plants will require pile foundations.

- The cost information provided by SeHAWK included membrane post-filtration for every facility.
- The cost information provided by SeHAWK assumed a heat exchanger for every facility.

Table B-8 summarizes biological treatment costs to the current industry. This estimate indicates incremental cost for biological treatment only and cost of physical/chemical pretreatment and biological treatment.

Table B-8
Biological treatment costs to industry for FGD wastewater, in June 2018 dollars

Industry	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Annualized Cost [b] ($M per year)
Incremental biological cost for SeHAWK[a]	843	33	113
Biological treatment cost including physical/chemical pretreatment	2,495	79	314

M = million
$ = U.S. dollars (June 2018)
Costs represent EPA's 2019 plant list (ERG, 2019), adjusted to account for retirements of R. D. Morrow (ID 1185) and Units 1 and 2 of Chesterfield Power Station (ID 4679) as of the end of 2018. EPRI's list also does not include Lewis & Clark (ID 394) which is at the 50-MW limit.
[a] Annualized cost based on 20-year equipment life and 7% interest rate.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 4

Comment Excerpt:

FGD wastewater

- We support EPA's proposed BAT, but with additional necessary revisions to numeric limits for selenium and mercury. We also encourage EPA to revise its cost estimates to more accurately reflect the complete costs associated with the installation and operation of the technological retrofit.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 18

Comment Excerpt:

C. EPA Should Revise its Cost Estimates to More Accurately Reflect Industry Practices.

EPRI estimated the total industry costs of CP+LRTR biological treatment systems for FGD wastewater. [22] EPRI used EPA's industry profile, which reflects changes to the industry up to October 2018, including new units, new wet FGD systems, coal unit retirements and fuel conversions, and modifications to FGD treatment and bottom ash systems.[23] The list of units EPRI used to generate these costs is therefore very similar to EPA's list.[24]

Table 1 compares EPA and EPRI total industry costs for Option 1 (CP only) and Option 2 (CP+LRTR) in terms of capital, annual O&M, and total annualized costs.

Table 1: Comparison of EPA and EPRI Costs for FGD Wastewater Treatment

	Source of Industry Cost	Capital Cost ($M)	Annual O&M Cost ($M/yr)	Total Annualized ($M/yr) @7%
Option 1 (CP Only)	EPA	$675	$42	$105
	EPRI	$1,652	$46	$202
Option 2 (CP + Bio)	EPA	$1,127	$76	$181
	EPRI	$2,495	$79	$314
Incremental Bio	EPA	$452	$33	$76
	EPRI	$843	$27	$107

EPRI's analysis shows EPA has significantly underestimated the industry costs for the model technology it has proposed for FGD wastewater (CP+LRTR). EPRI estimates that the differential between it costs and EPA's costs for CP+LRTR is about 1.7.[25]

EPRI provides a number of reasons why EPA's costs are underestimated. The major differences include the following, each of which is discussed in more detail in the subsections below.

1. EPA underestimated the peak FGD wastewater design flow used to size equipment.
2. EPA underestimated the cost factors it used to calculate a total installed cost from the vendor estimates.
3. EPA underestimated the need for redundancy of chemical precipitation equipment.
4. EPA underestimated costs for plants with high-total dissolved solids ("TDS") FGD wastewater.[26]

22 Id. at 2-1 to 2-2.
23 Memorandum from Ryan Novak, Eastern Research Grp., Inc., Changes to Industry Profile for Coal-fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule 2-3 (July 31, 2019) (Docket ID No. EPA-HQ-OW-2009-0819-7373).
24 Compare id., with Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 2-1.

25 Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 2-1 to 2-2.
26 Id. at 2-2

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 22

Comment Excerpt:

4. EPA likely underestimated costs at plants with high-TDS FGD wastewater.

EPRI also states that EPA underestimated costs at plants with FGD wastewater high in TDS.[34] FGD wastewater with high TDS levels, including swings in TDS levels which can occur due to FGD system operations, can cause operational challenges to biological treatment systems. EPA obtained cost data from Frontier Water Systems, the vendor of a bioreactor system, and Frontier states it has demonstrated "successful treatment of a broad range of FGD water chemistries, with TDS averaging 17,556 mg/L (36,000 mg/L maximum) and chloride averaging 7,000 mg/L (17,200 mg/L maximum)."[35] Frontier also explains that these thresholds have not yet been determined for its technology because pilot data to date is empirically based on site-specific water chemistry conditions available for testing.[36]

EPRI reports that a recent pilot test with FGD wastewater of approximately 35,000 mg/L TDS by another leading vendor using the same biological processes needed to dilute the wastewater to below 20,000 mg/L TDS.[37] The dilution of FGD wastewater to meet vendor specifications increases the cost of treatment. EPRI accounted for this in its cost estimates by assuming 3% of plants will require dilution with lower TDS water. [38] EPA should consider high-TDS FGD wastewaters when estimating costs for biological treatment.

34 Id.
35 See Memorandum from Danielle Stewart, Eastern Research Grp., Inc., Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology, supra note 30, app. 1 at 7.
36 Id.
37 Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 2-8.
38 Id. 39 See Proposed Rule, 84 Fed. Reg. at 64,632.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 20

Comment Excerpt:

2. EPA's indirect costs are significantly underestimated.

Indirect costs represent a significant portion of total installed costs. These indirect costs include engineering, materials, and construction costs for necessary items not within the vendor's scope of supply, such as foundations, steel, piping, pumps, instrumentation, controls, electrical cable, electrical equipment, control buildings, and other activities such as demolition or relocation of existing infrastructure. These costs are highly dependent upon such factors as distance from the installation to the unit, overall space limitations, redundancy requirements, terrain and associated infrastructure considerations. For example, for several wastewater treatment installations that have been completed at Southern Company system plants, the actual indirect costs were four to five times higher than the primary equipment costs.

EPRI has applied standard industry practice to estimating costs and computed indirect costs at 2.5 times the vendor cost.[29] There is very little detail provided in the record regarding what cost factors EPA used. Some insights are available in the Eastern Research Group memorandum, "Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology."[30] EPA's indirect costs ("missing capital costs") appear to be roughly 0.6.[31] We therefore urge EPA to fully consider all costs associated with installing wastewater treatment technologies to meet the ELG limits.

29 See Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 2-3 to 2-4.
30 See generally Memorandum from Danielle Stewart, Eastern Research Grp., Inc., Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology 2 (Oct. 8, 2019) (Docket ID No. EPA-HQ-OW-2009-0819-8156).
31 See id. at 2.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 53

Comment Excerpt:

XIII. EPA's Cost Calculations for FGD Wastewater Treatment Underestimate the True Costs of FGD Retrofits.

As EPRI's analysis makes clear, EPA has underestimated the costs of the model technology it has proposed for FGD wastewater, chemical precipitation followed by low residence time biological treatment (CP+Bio). EPRI estimates that the differential between its costs and EPA's for CP+Bio is about 1.7. EPRI 2020 Comments at 2-1. The table below shows the comparison in terms of capital and annual O&M costs.

Comparison of CP+Bio Costs, EPA and EPRI[72]

Source of Industry Cost	Capital Cost ($M)	Annual O&M Cost ($M/yr)	Total Annualized ($M/yr) @ 7 Percent
EPA	$1,127	$76	$181
EPRI	$2,495	$79	$314

EPRI made significant efforts to update its industry profile to match EPA's October 2018 industry profile. This included adding in new units, identifying new wet FGD systems, and accounting for coal unit retirements and fuel conversions and modifications to FGD wastewater treatment and bottom ash systems. Id. Therefore, the list of units EPRI used to generate capital and O&M costs is very similar to EPA's list. *Id.*

EPRI describes a number of reasons why EPA's estimates fall short. First, EPA apparently underestimated the peak FGD wastewater design flow used to size equipment. Instead of using the approach it used in the 2013 proposed ELG rule, which was based on applying a mean capacity factor of 1.99 to reported average flow rates, EPA uses average flow for purposes of designing the new systems. *Id.* at 2-2 – 2-3. But as EPRI points out, wet FGDs generally manage their recycling levels based on chloride/halogen concentrations, as well as the concentration of fines. *Id*. at 2-3. According to EPRI "[h]igher concentrations of fines could potentially disrupt dewatering, gypsum quality and ORP stability in some wet FGD systems." *Id*. Therefore, it is erroneous to assume that all plants can reduce their flow rates.[73] In contrast, EPRI used peak wastewater treatment system design flow rates from the 2013 ICR or applied the same mean capacity factor that EPA used in 2013 to the plant's reported typical purge flow rate. *Id*. This is a substantial difference between EPRI's approach and EPA's.

EPRI also thinks that EPA apparently underestimated cost factors (e.g., cost factors for tie-ins of vendor equipment, bonding and insurance, site preparation work, etc.) used to calculate a total installed cost from vendor estimates. *Id.* at 2-3 – 2-7. While EPRI used industry standard practice for cost factors, analysis of the available information indicates that EPA did not. EPRI suggests that EPA clarify its cost estimating methodology. *Id*. at 2-3.

EPA also may have underestimated the redundancies needed for chemical precipitation systems. EPRI believes that industry units that are base load will have a higher rate of redundancy (2x100 percent), while peaking units may choose a lower level of redundancy (2x60 percent). *Id*. at 2-7 – 2-8. In 2013, EPA assumed treatment trains of 2x60 percent and presumably is applying that same level of redundancy again.

EPRI also believes it is likely EPA underestimated costs at plants with FGD wastewater high in TDSs. EPRI notes that EPA cites to Frontier's statement that its biological treatment system can successfully treat up to 36,000 mg/L TDS. *Id.* at 2-8. However, in an EPRI study, another vendor of biological treatment systems had to dilute the FGD wastewater to below 20,000 mg/L TDS. Id. This information calls into question whether either biological treatment system can successfully manage TDS above 20,000 mg/L without dilution, which would increase the cost of treatment.

For all these reasons, it is likely that EPA has underestimated the costs of CP+Bio.

[72] EPRI 2020 Comments at 2-1.
[73] UWAG members also report there are many other factors that affect a company's ability to reduce flow rates, including limitations on cycling up based on biological treatment supplier influent restrictions; limitations on the ability to reduce treatment sizing by recycling additional blowdown water back to the FGD due to scaling concerns; and additional investment needed to obtain the recycle infrastructure needed to achieve a smaller flow rate, including non-metal materials that could reduce flow by concentrating chlorides and other dissolved constituents.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 3

Comment Excerpt:

The cost of ultrafiltration ("UF") is considerably higher than EPA has estimated and particularly where systems designed to meet the 2015 Rule have not included it. For example, TVA has been designing and building wastewater treatment systems to meet targets set at 75% of the 2015 monthly average ELG limits. At TVA's Kingston plant, ultrafiltration (UF) was not originally included in the cost estimate either in a rough order-of-magnitude (ROM) estimate from Frontier Water Systems™ (Frontier) or in the selected design using the GE ABMet® biological treatment system. In the case of the selected design (GE ABMet®) UF was not planned because it was not needed to meet 2015 ELG performance guarantees. With the proposed lower ELGs for mercury, a UF system would be required. The cost of adding UF to biological treatment is substantial; a ROM cost estimate for adding UF to Kingston adds approximately $12 million (M) or approximately 45% as compared to the cost of planned biological treatment designed to meet the 2015 ELGs. [1] Compliance with the proposed lower limits for mercury will also lead to increased operation and maintenance costs.

[1] ROM from AECOM on UF

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 5

Comment Excerpt:

TVA is concerned that EPA has underestimated the installed costs to provide UF as a polishing step, especially if UF is not already included in the site's treatment train proposal. On Page 64632, EPA asserts that " ... including the ultrafilter polishing stage, require[es] little more than a concrete foundation, electricity supply, and piping connections." TVA believes this is an oversimplification of the requirements for UF because the UF units would need to be located indoors. Indeed, the *EPA-HQ-OW-2009- 0819-8156 Updated LRTR Cost Method memo* (Frontier memo) dated October 8, 2019, states that Frontier is excluding the following items from its cost estimate:

- Integration with plant DCS
- Pump MCCs
- Plant Air supply
- Buildings/footings/foundations and on site construction
- On site electrical
- Equipment offloading/ installation
- Interconnecting piping,

the sum of which can contribute significantly to the overall cost. In addition, the Frontier memo also excludes effluent tanks and pumps that might be required at some if not all sites and would add to the cost.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 6

Comment Excerpt:

In addition, EPA may be underestimating operations and maintenance (O&M) costs for UF. If O&M estimates are based on limited pilot run times, O&M cost data could be skewed low. Frequent UF cleaning may be needed with longer full-scale operation over multiple seasons as fouling could occur due to microbial growth and potential solids carryover from the biological treatment system . Frequent cleaning results in higher chemical costs and could cause increased wear of the UF system requiring replacement that is more frequent than estimated. The Frontier memo indicated its UF replacement frequency was estimated to be twelve years, Suez estimates their UF system will last between eight to ten years, depending upon the characteristics of the wastewater being treated. [2] Shorter UF lives will affect O&M cost estimates. Additionally as documented in the Frontier memo, the target ELGs that were used in Frontier's cost estimates were higher than the proposed ELGs for mercury and selenium which could understate costs.

[2] Email from Mike Newsom, Suez.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 46

Comment Excerpt:

COST-EFFECTIVENESS OF POLLUTANT REMOVAL

6.1 **FGD chemical precipitation and biological pollutant removals.**

Throughout the 2019 ELG proposed rule and supporting documentation, EPA now expresses pollution reduction in total pounds, whereas in the 2015 version of the steam electric power generating ELG (and ELGs for other industry categories), EPA used both total pounds and toxicweighted pound equivalents (TWPEs). TWPEs reflect the relative toxicity of pollutants (for example, mercury has a higher toxicity factor than chlorides). EPA also presents pollution reduction relative to a baseline of compliance with the 2015 ELG Rule. To compare with EPRI's estimates of pollution reduction, we back-calculated pollution reduction for each technology as described in Table 6-1. Our pollution reduction estimating approach is documented in Appendix G. As is shown in this tabulated comparison, EPRI's calculated pollutant removal reduction was roughly half of EPA's estimate for biological treatment.

On a per plant basis, EPRI's pollutant removal calculation shows that the pollution reduction of CP + Biological is roughly three times greater than incremental biological pollution reduction as shown in Table 6-1.

EPA appears to calculate removal simply by sum of TDS and TSS. EPRI uses the sum of individual pollutants. For incremental biological, the sum of the EPA's TSS plus TDS is 65 percent greater than the sum of the other pollutants presented. EPRI presents the pollution reduction of biological treatment, rather than removal by both chemical precipitation plus biological to help focus the evaluation of cost versus benefits of biological treatment.

Table 6-1
Pollution reduction estimates by EPRI and EPA

Treatment	EPRI # of Plants	EPA Mass (lb/yr)	EPRI Mass[1] (lb/yr)	EPRI Mass per plant (lb/yr per plant)	EPA TWPE/yr	EPRI TWPE/yr [1]	EPRI TWPE/yr per plant
Chemical Precipitation + Biological [2]	59	1,380,000,000 [3]	115,000,000	1,950,000	452,000 [4]	277,000	4,690
Incremental Biological [5]	32	289,000,000 [6]	32,500,000	1,016,000	157,000 [7]	50,100	1,570

[1] EPRI mass and TWPE estimates based on calculations described in Appendix H
[2] CP + Biological for EPA's estimates are shown for Option 3. EPRI shows the values for Option 3 because this option provides the cleanest comparison for CP + Biological only. There are a few plants included in this EPA estimate that EPA assumed would take the VIP option, which increases EPA's estimated benefit of biological treatment.
[3] EPA's value based on Option 3 in Table 6-3 in EPA's Technical Development Document [EPA, 2019]
[4] EPA's value based on adding the TWPE total of Option 3 in Table 4 to the TWPE total of the Baseline in Table 1 based on ERG's Industry-Level Baseline document. [ERG, 2019a]
[5] EPA's incremental biological was calculated by subtracting Option 1 by Option 3. The difference in technology demonstrates incremental bio with the exception of high FGD flow facilities as listed in Option 3. EPRI estimates that only one facility falls under that technology and that this facility only contributes to 14% of the total industry flow. Therefore Option 1 minus Option 3 can represent incremental biological.
[6] EPA's value is based on Option 1 minus Option 3 in Table 6-3 in EPA's Technical Development Document
[7] EPA's value is based on adding the TWPE total of Option 3 in Table 4 to the TWPE total of the Baseline in Table 1, which is based on ERG's Industry-Level Baseline document. (ERG, 2019a) and subtracting that from adding the TWPE total of Option 1 in Table 2 to the TWPE total of the Baseline in Table 1 from the same document.

Commenter Name: Major L. Clark, III and David Rostker
Commenter Affiliation: Office of Advocacy, U. S. Small Business Administration
Document Control Number: EPA-HQ-OW-2009-0819-8310-A1
Comment Excerpt Number: 6

Comment Excerpt:

[In particular, EPA should be closely examining the TWPE metric for the following requirements.]

...

- **Low Hydraulic Residence Time Reduction Biological Treatment:** EPA proposes BAT for units that exceed a net generation of 876,000 MWh based on treatment of FGD wastewater including a relatively new technique, low hydraulic residence time biological treatment (LRTR). To demonstrate the effectiveness of this technology, EPA relies on data from pilot studies and statistical analysis that excluded data that may reflect normal operating conditions. [13,14] Pilot tests do not necessarily represent commercial full-scale operation or the operating cycle of many coal-fired power plants. For this reason, EPA may be overstating the cost-effectiveness of this technology. EPA should reconsider whether it has the necessary data to establish effluent limits based on this technology operating in real world conditions.

[13] Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category - DCN SE07101, November, 2019, pp. 8-12, available at regulations.gov Document ID EPA-HQ-OW-2009-0819-8211
[14] Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards - DCN SE08055, September 2019, p. 5, available at regulations.gov Document ID EPA-HQ-OW-2009-0819-8193.

Commenter Name: Tim Pickett
Commenter Affiliation: Frontier Water Systems
Document Control Number: EPA-HQ-OW-2009-0819-8295-A1
Comment Excerpt Number: 1

Comment Excerpt:

In fact, since publication of the 2015 draft rule, multiple pilot trials have been successfully implemented and several large fullscale treatment plants have been installed, treating selenium, nitrate and metals. Over this time period, these systems have demonstrated the capability to meet or exceed the Effluent Limitation Guidelines as proposed in the 2019 revision.

Commenter Name: Tim Pickett
Commenter Affiliation: Frontier Water Systems
Document Control Number: EPA-HQ-OW-2009-0819-8295-A1
Comment Excerpt Number: 2

Comment Excerpt:

Recent focus by our company have been directed to reducing the cost of treatment while providing operational flexibility to accommodate the increasingly intermittent power production cycles of coal fired steam electric generation facilities. Our modular approach to water treatment minimizes installation costs by prefabricating much of the equipment off site. The overall size of the systems has decreased, resulting in a smaller footprint and less balance of plant infrastructure. Treatment plant operational protocols and system modularity offers turn down and ramp up capability to accommodate fluctuations in flow to the system. Further innovation has resulted in the development of the first mobile bioreactor platform for ELG compliance of FGD blowdown. Our mobile systems are offered as a lease or purchase which provides additional operational and budgetary flexibility to the end-users.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 19

Comment Excerpt:

A. The Proposed Model Technology is Well Supported But Should Be Adjusted Based on a Number of Factors.

The LRTR systems used as the model technology in the Proposed ELG Rule can achieve significant removal of selenium and nitrate/nitrite using fixed film bioreactors in smaller, more compact reaction vessels than the high residence time biological reduction (HRTR) used in the biological treatment system evaluated by EPA in the 2015 ELG Rule. Crucially, the LRTR systems utilized as the model technology in the Proposed ELG Rule are less costly than those contemplated by the 2015 ELG Rule, have smaller footprints, and require fewer process changes and facility modifications. LRTR systems therefore better comport with the requirement of CWA section 304(b)(2)(B) that BAT determinations "shall take into account the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, nonwater quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate." 33 U.S.C. §1314(b)(2)(B).

Commenter Name: American Coal Council (ACC)
Commenter Affiliation: American Coal Council (ACC)
Document Control Number: EPA-HQ-OW-2009-0819-8315-A1
Comment Excerpt Number: 1

Comment Excerpt:

ACC supports EPA's setting of the best available technology (BAT) limits for FGD wastewater treatment based on the use of low hydraulic residence time biological reduction (LRTR). This is an improvement over the high residence time biological reduction (HRTR) that was the basis in the 2015 Rule. Generally, LRTR systems are smaller, less complex, and require fewer modifications to a facility's footprint than HRTR systems while achieving similar efficacy.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 1

Comment Excerpt:

<u>Duke Energy Supports EPA's Model BAT Technology for FGD Wastewater</u>

Duke Energy supports EPA's proposal identifying chemical precipitation followed by a low hydraulic residence time (LRTR) biological treatment including ultrafiltration as the BAT basis for control of pollutants discharged in FGD wastewater. Both chemical precipitation and biological treatment are well demonstrated technologies that are available to steam electric facilities for use in treating FGD wastewater. Duke Energy has used chemical precipitation followed by high residence time reduction (HRTR) biological treatment for the past decade at its Allen and Belews Creek Steam Stations and recently installed chemical precipitation followed by LRTR biological treatment including ultrafiltration at two stations with plans for installation at an additional station in 2020. LRTR biological treatment can achieve significant removal of selenium and nitrate/nitrite in smaller, more compact reaction vessels than the HRTR biological treatment system evaluated by EPA in the 2015 ELG Rule. This results in the LRTR having a smaller footprint and requiring fewer process changes and facility modifications making it less costly than the HRTR considered by EPA in the 2015 ELG Rule.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 12

Comment Excerpt:

<u>EPA is Correct to not Propose Non-Voluntary Limits on Bromides under the Effluent Limitation Guidelines</u>

The effluent limitation guidelines (ELGs) are technology-based regulations based on the performance and costs of demonstrated wastewater control and treatment technologies. First, EPA identifies the best available technology that is economically achievable for that industry and, secondly, sets regulatory requirements based on the performance of that technology. If additional regulatory requirements are necessary to meet water quality standards in the receiving water, then states and/or permit writers can impose additional water quality-based effluent limits (WQBELs).[34] As stated above, EPA appropriately selected chemical precipitation followed by a LRTR biological treatment including ultrafiltration as the BAT basis for control of pollutants discharged in FGD wastewater. This technology is both available, well demonstrated and economically achievable having been installed at several sites nationwide. As stated by EPA, ammonia, boron, bromide, chloride, cyanide, and total dissolved solids (TDS) are not effectively treated by this technology[35], thus, it is inappropriate to establish technology-based regulatory requirements for these constituents under the effluent limitation guidelines based on EPA's chosen model technology.

34 Clean Water Act section 303(b)(1)(c)) and NPDES regulations (40 CFR 122.44(d)).
35 U.S. Envt'l Prot. Agency. "Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category." EPA-821-R-19-009 (November 2019), at 8-4.

Commenter Name: Caitlin McHale
Commenter Affiliation: National Mining Association (NMA)

Document Control Number: EPA-HQ-OW-2009-0819-8327-A1
Comment Excerpt Number: 2

Comment Excerpt:

II. Flue Gas Desulfurization Wastewater

NMA supports EPA's proposal to set the Best Available Technology (BAT) effluent limitations technology for FGD wastewater based on treatment using chemical precipitation followed by a low hydraulic residence time biological treatment (LRTR) including ultrafiltration.[5] Chemical precipitation and biological treatment are "well-demonstrated technologies that are available to steam electric facilities for use in treating FGD wastewater"[6] and help remove pollutants such as selenium, heavy metals, nitrate/nitrite, and others. The LRTR systems that EPA proposes as the model technology are a welcome improvement over the high residence time biological reduction (HRTR) used in the biological treatment system evaluated by EPA in the 2015 Rule. LRTR systems cost less than HRTR systems, have smaller footprints, and require fewer process changes and facility modifications. Section 304(b)(2)(B) of the Clean Water Act (CWA) requires that BAT determinations "shall take into account the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control technologies, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate."[7]

EPA's proposed limitations for arsenic, nitrate/nitrite as N, and selenium in FGD wastewater better align with the CWA and will provide much-needed regulatory certainty for our members and their customers.

[5] 84 Fed. Reg. 64630 and 64631.
[6] Id.
[7] 33 U.S. § 1414(b)(2)(B).

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 14

Comment Excerpt:

4. EPA incorrectly disregards electrical generation operational challenges when establishing standards for FGD WW BAT.

The proposal identifies FGD WW BAT as using chemical precipitation followed by a low hydraulic residence time biological treatment including ultrafiltration[14]. EPA states that this treatment methodology is well-demonstrated and available to steam and electric facilities, therefore set discharge standards accordingly. However, EPA did not adequately consider the challenges associated with operating biological treatment systems as result from a facility's unique electric generating operations. There are some electrical generating variabilities that could have huge impacts on the operation of a biological treatment system and attaining compliance with regulatory standards. In an effort to meet electrical grid demands while simultaneously keeping fuel costs low to allow for low rates to consumers, some electric utilities will burn various types of coals. Coal is derived from various sources and locations across the country, therefore, the constituents of coal is different. For example, the chloride levels of coal derived from the eastern portion of the United States is vastly different than coal mined from the Powder River Basin (Commonly referred to as PRB). Likewise, the BTUs and transportation costs of coal vary based on respective sources. These differences in coal allow for companies to strategically burn different blends of coal in order to meet electrical demand and keep electric rates low. However, this fuel blending results in fluctuating operations of the FGD systems because of the different constituents found within different types of coal. The fluctuating operations of the FGD system results in different rates of FGD absorber blowdown to the FGD WW treatment system. Such variations in flows can have severe detrimental effects to biological treatment systems. EPA rejected[15] the argument that biological treatment efficiency was subject to coal blending in the proposal by stating that steam and electric facilities have operated biological treatment systems where fuel blending has occurred. However, these facilities do not adequately represent the degree of coal blending that occurs throughout the industry as the BAT for FGD WW in the proposal was based upon limited pilot study data. Although EPA acknowledges coal blending, the proposal does not address the various ratios of coal blends (which is different from facility to facility) nor do they address the timeframe which coal blends can change. Different facilities have the capability to adjust coal blends within a matter of hours, where others only have coal handling systems that allow them to change blends within days. The ability to change coal blends frequently to economically meet changing electrical demand is beneficial to the ratepayer but creates yet another operational issue for biological treatment systems. EPA needs to give variable electrical generation operations more consideration when finalizing the FGD WW discharge limits and acknowledge that adjusting discharge limits can provide the needed flexibility and synergy for electrical generation and environmental compliance.

[14] Fed. Reg. Vol 84, p. 64631
[15] Fed. Reg. Vol 84, p. 64631

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 2

Comment Excerpt:

B. CCIG Supports Proposed Revisions to FGD Wastewater Limits, But Requests Clarification on Mercury Limits

CCIG supports EPA’s proposed model technology and limits for arsenic, selenium, and nitrate/nitrite for FGD wastewater, but requests that EPA clarify the data that was used to derive the proposed mercury limits and consider increasing the proposed limits to account for full-scale plant operation. EPA's reliance on chemical precipitation and LRTR biological treatment as the technology basis for FGD wastewater is appropriate as both technologies are well-demonstrated and available to steam electric facilities. As EPA notes in the Preamble to the Proposed Rule, both technologies are available to ELG facilities; are economically achievable; and, when used in combination, provide substantial reductions in the discharge of pollutants beyond what either technology would be able to provide alone.[7] Chemical precipitation has been used for decades at thousands of industrial facilities nationwide, including many steam electric power plants. Regarding biological treatment, the LRTR treatment systems EPA proposes to use as part of the technological basis for BAT are less costly than high residence time biological reduction (HRTR) systems and require fewer process changes than HRTR options.[8]

[7] Id. at 64,631.
[8] Id.

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 2

Comment Excerpt:

Revisions to Effluent Discharge Limitations for FGD Wastewater

In the 2015 ELG rule, EPA set overly stringent limitations for metals and other constituents that cannot be reliably achieved by the "best available" control technology selected by EPA itself in the rulemaking. That control technology consisted of a chemical precipitation system to remove suspended and dissolved solids, combined with a biological treatment system to remove nitrogen compounds, selenium and other metals. The type of bioreactor system used to set the current limitations employs a long residence time of 10 to 16 hours for completing the microbial processes for removing contaminants and, for that reason, is significantly more costly than the alternate biological treatment system included in the proposed ELG rule. The newly selected "low-residence" biological treatment system with a much shorter residence time of 1 to 4 hours will achieve "comparable" reductions to the current system because it will "require significantly less process or facility footprint modifications than the current long-residence system."[5]

America's Power generally supports this new approach for setting the FGD wastewater limitations. The new low-residence biological treatment system will reduce annual compliance costs, plus eliminate many of the technical challenges to reliably achieving the ELGs for metals and other constituents under varying operating scenarios (including load cycling in response to fluctuating demand), extreme climate conditions, and switching coal types.[6]

However, America's Power has concerns regarding the proposed effluent discharge limitations for mercury and selenium. In the case of mercury, the proposed rule would drastically reduce the limitation from 788 to 85 nanograms per liter based on the use of ultrafiltration with low-residence time biological treatment systems. We believe EPA's assumption that this control system can cost-effectively remove 90 percent of the mercury in the FGD wastewater is highly questionable and, as a result, has led the Agency to propose an unreasonably stringent mercury limit. Similarly, we believe that the proposed new selenium limitation of 76 micrograms per liter has not been increased enough to account for the high selenium levels that are likely to result from burning subbituminous coals, frequent load cycling, and other operational factors that typically result in highly variable FGD wastewater.

5 84 Fed. Reg. at 64,627, 64,631.
6 84 Fed. Reg. at 64,627, 64,631.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 17

Comment Excerpt:

IV. The Proposed Rule's FGD Wastewater Technology Basis and Compliance Dates Are Well Supported, Achievable, And Provide the Necessary Time For Implementation, However EPA Should Consider Whether To Adjust Those Limits Based On Variability And Other Factors.

EPA proposes to revise the BAT limits applicable to FGD wastewater based on model technology that uses the application of chemical precipitation followed by a low hydraulic residence time biological reduction (LRTR) treatment including ultrafiltration. 84 Fed. Reg. at 64,638. As EPA notes, chemical precipitation and biological treatment are demonstrated technologies available to steam electric facilities for use in treating FGD wastewater that together help remove pollutants such as heavy metals, selenium, nitrate/nitrite, and suspended and precipitated solids. Id. at 64,631.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 10

Comment Excerpt:

For FGD waste, EPA is proposing to weaken the effluent limits based on a less-protective technology; while EPA claims the additional pollution would be "de minimis," in fact the agency is proposing to authorize selenium limits three times higher than those in the 2015 rule.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.

Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 30

Comment Excerpt:

EPA attempts to justify tripling selenium limits because low-residence time systems supposedly experience "increased short-term variability" over high-residence time systems.[50] However, the end result of this excuse is to allow sharply increased pollution, not just in occasional spikes but day after day, month after month. EPA may hope that these systems perform comparably to high-residence time bioreactors in the long term, but the proposed limits would allow power plants to discharge pollution at levels triple the 2015 Rule not just occasionally but indefinitely. EPA's proposal to drastically relax not just daily maximum limits but monthly averages indicates that low-residence time systems are not just less consistent than high-residence time systems—they are "demonstrably inferior."

This justification also fails because utilities must account for variability by improving processes and operations, not relying on EPA to weaken limits. High-residence time systems also experience variability, which EPA foresaw and addressed in its 2015 rulemaking. In the 2015 Rule, EPA set the daily maximum at 23 micrograms per liter and the monthly average at 12 micrograms per liter. These limits were based on "long-term average effluent values and variability factors that account for variation in performance at well-operated facilities that employ the technologies that constitute the bases for control."[51] Now, EPA is proposing to more than triple the daily maximum to 76 micrograms per liter, and nearly triple the monthly average to 31 micrograms per liter.

In the 2015 rulemaking, EPA acknowledged that "some dischargers, including those that are operating [BAT], may need to improve their treatment system operations in order to consistently meet the effluent limitations and standards. This is consistent with the CWA, which requires that discharge limitations and standards reflect [BAT] or the best available demonstrated control technology."[52] As EPA stated: "such exceedances [due to variability] can be controlled by diligent process and wastewater treatment system operational practices" or by "upgrad[ing] or replac[ing] existing treatment systems to ensure that the treatment system is designed to achieve performance that targets the effluent concentrations at the long-term average."[53]

At its Belews Creek and Allen sites, Duke Energy has seen variability in selenium reductions due to fuel changes,[54] and it addressed this issue—as the Clean Water Act requires and EPA foresaw—by improving its high residence time treatment systems to include ultrafiltration in order to "to meet the ELG effluent guidelines."55

There is no reason to set selenium limits three times higher—as EPA now proposes to do—because of variability. Like Duke Energy has done in North Carolina, utilities must deal with variability by making improvements to ensure they can consistently meet the limitations, rather than asking regulators to triple the amount of pollution allowed. Weakening limits eliminates the incentive to improve performance. And if low-residence time units experience such dramatic, persistent variability that they pollute more even when performing optimally, then that should further disqualify the technology as BAT. EPA must not let the tail wag the dog by tripling pollution limits.

[50] 84 Fed. Reg. at 64,632.
[51] 2015 Rule at 67,869.
[52] 2015 Rule at 67,870.
[53] 2015 Rule at 67,870.
[54] EPA FGD Variability Memo; Duke Energy FGD Variability Memo.
[55] Duke Energy Carolinas Response to North Carolina Public Staff Data Request, Data Request No. NCPS 42, Docket No. E-7, Sub 1214 (Oct. 25, 2019) (Attachment 9); see also Direct Testimony of Steve Immel for Duke Energy Carolinas, LLC, North Carolina Utilities Commission, Docket No. E-7, Sub 1214, 6 (Sept. 30, 2019), available at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9ea94bc4-c977-4655-8540-e5c19c6c5123(Attachment 10) ("[The Company has made significant investments within its coal fleet to meet environmental regulations to allow for the continued operation of active plants, including the … Effluent Limitations Guidelines ("ELG"), totaling approximately $689 million, largely driven by dry bottom ash conversions, wastewater treatment enhancements, and lined retention basins projects.").

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 32

Comment Excerpt:

EPA attempts to further justify tripling selenium limits by arguing that low-residence time systems are less expensive, take up less space, and require fewer process changes than high residence time systems. However this justification fails too because the Clean Water Act does not require polluters to adopt any one specific treatment technology—it simply requires polluters to meet effluent limitations, which are set based on best available technology.

These effluent limitations are being met now—and indeed, even low-residence time systems are capable of meeting the existing limits. At North Carolina's Marshall site, Duke Energy determined it could meet the limits that were based on high-residence time biological treatment by installing a low-residence time biological treatment system—Frontier's SeHAWK technology. In April 2018, NC DEQ issued a permit including limits based on the 2015 ELGs (for selenium—a daily maximum of 23 micrograms per liter, and monthly average of 12 micrograms per liter), and Duke Energy did not challenge the permit.[61] The ability of this system to meet the existing limits further undermines EPA's purported justification for weakening them.

[61] NC DEQ, NPDES Permit for Marshall Steam Station, No. NC0004987, Condition A(7), Effluent Limitations and Monitoring Requirements (Internal Outfall 004) (May 1, 2018), available at https://files.nc.gov/ncdeq/Coal%20Ash/NPDES%20Permitting%202015/Marshall%20WW%204987-final%20major%20mod-2018.pdf (Attachment 12) ("Marshall Permit").

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.

Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 47

Comment Excerpt:

EPA's preferred BAT option for FGD wastewater – chemical precipitation plus a so-called low residence time reduction biological treatment – is similarly flawed. EPA acknowledges that high residence time reduction biological systems are, in fact, technically and economically achievable and widely used in the industry.[168] Nevertheless, the agency does not even include high residence time systems as a BAT option, but instead considers only low residence time systems, which result in substantially weaker numeric limits for selenium and higher variability in pollution reductions.[169] EPA asserts that the long-term average reductions for low residence time systems are "comparable" to high residence systems,[170] but fails to grapple with the fact that low residence time systems triple the so-called BAT limits for selenium, as well as higher arsenic limits. And contrary to EPA's conclusory assertion that the two technologies result in comparable variability, low residence time systems actually result in double the pollutant variability of high residence time systems. As with its failure to explain its proposal to triple the numeric limit for selenium, EPA fails to acknowledge or explain those significant differences in variability. Even if the long-term variability was comparable (and it is not), the agency fails to explain how long-term average pollution reductions adequately protect against short-term spikes in pollution that may harm human and aquatic health. Moreover, the record reflects only five examples of low residence time systems, and EPA does not provide sufficient non-confidential data to provide for a meaningful comparison of the technologies. Instead, the record makes clear that EPA's proposal to walk back its 2015 biological treatment technology standards is impermissibly and exclusively based on cost.

For the reasons described below, EPA's proposed redefinition of BAT for FGD wastewater is arbitrary, capricious, and contrary to the CWA. There is no basis in the record for EPA to weaken the technological standard for FGD wastewater by allowing EGUs to install less effective low residence time biological systems when high residence time systems are available, economically achievable, and already widely in use at the best-performing plants in the industry.

[168] 84 Fed. Reg. at 64,627.
[169] Id. at 64,632, 64,661.
[170] Id. at 64,631.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 53

Comment Excerpt:

Second, EPA's assertion that low and high residence time systems achieve "comparable" pollution reductions is demonstrably false. Indeed, a cursory comparison of EPA's 2015 BAT limits (which relied on *high* residence time systems)[197] with revised BAT limits (which rely on low residence time) makes clear that the agency is now proposing to substantially weaken the numeric limits for selenium,[198] one of the key pollutants for which biological treatment is used in the first place.[199] In fact, EPA's proposed low residence time BAT proposal would more than triple the daily maximum selenium discharges that the agency found in 2015 are achievable using high residence time. EPA's proposed low residence time BAT would similarly nearly triple the 30-day average limit for selenium, and increase arsenic concentrations. As noted, biological treatment systems are critical for reducing selenium levels, and the agency arbitrarily fails to acknowledge, let alone grapple with the fact that its proposed BAT revision for such treatments (low residence instead of high residence time) would triple the resulting concentrations of harmful selenium.

BAT must represent the best-performing technology.[200] Despite that clear mandate, EPA proposes to reverse its 2015 BAT determination and select a low-residence time technology for selenium that, according to EPA's own data, results in significantly higher selenium levels than readily available and economically achievable high-residence time technology. EPA's proposal to adopt low residence time as BAT is not only unlawful on the merits—low residence time technology is clearly not the best performing technology for selenium—but the agency arbitrarily fails to acknowledge or explain its reversal. [201]

[197] 84 Fed. Reg. at 64,627.
[198] Compare 80 Fed. Reg. at 67,895 (establishing a 23 ug/L daily numeric limit for selenium (codified at 40 C.F.R. § 423.13(g)(1)(i)), with 84 Fed. Reg. at 64,676 (proposing a 76 ug/L daily numeric limit for selenium).
[199] 84 Fed. Reg. at 64,632, 64,661.
[200] See, e.g., *Chem. Mfrs. Ass'n*, 870 F.2d at 226.
[201] *FCC v. Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 54

Comment Excerpt:

Third, and as explained in the attached technical comments of Dr. Ranajit Sahu, low and high residence time systems do not actually result in comparable long-term average concentrations.[202] As an initial matter, EPA asserts that "while the effluent" from low residence time systems is "more variable than" than high residence time systems, "both technologies achieve long-term average effluent concentrations for selenium lower than 20 mg/L [sic]"[203] EPA fails, however, to explain why that 20 ug/L threshold is even relevant, given that the long-term average for low residence time systems is more than double high residence time systems.

Again, BAT requires EPA to select the best performing technology. That low residence time biological treatment systems achieve a long term average concentration that is better than some arbitrary threshold is completely irrelevant. Instead, EPA must consider how available technologies compare to each other. Here, the long-term average selenium concentration for high residence time systems is less than half the concentration of low-residence time systems (7.4 ug/L versus 16.6 ug/L), making clear that high residence time systems actually perform significantly better.

As explained in Dr. Sahu's report, the long term data make clear that low and high residence time systems do not result in comparable or similar long term average concentrations, and that high residence time technology is significantly more effective at removing selenium form FGD wastewater. In the face of its own data showing that low residence time systems result in significantly higher short- and long-term selenium concentrations than high residence time systems, EPA's proposal to select low residence time technology as BAT is arbitrary and capricious.

[202] Dr. Ranajit (Ron) Sahu, Technical Comments on EPA's Proposed Rule to Revise the Best Available Technology (BAT) Effluent Limitations Guidelines (ELGs) for Flue Gas Desulfurization (FGD) Wastewater and Bottom Ash Transport Water (BATW), at 31-37 ("Sahu Expert Report") (attached).
[203] 84 Fed. Reg. at 64,631.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 56

Comment Excerpt:

Fourth, also as explained in Dr. Sahu's analysis, EPA's assertion that low and high residence time systems have similar variability is similarly false. In developing the 2019 BAT limits, EPA apparently used pilot test effluent data from five unidentified plants. Although EPA withheld the underlying effluent data as confidential (so it is impossible to independently evaluate), EPA's summary of the data reflects wide variability in selenium concentrations—from 7.711 to 26.813 ug/L.[204] While the lowest of these values is roughly comparable to high residence time, the other four plants have significantly higher variability, calling into question EPA's suggestion that there is no "meaningful difference in long-term pollutant removals."[205] The data above also show the significantly higher daily (ranging from 2.989 to 5.076) and monthly (ranging from 1.551 to 1.994) variability factors. As explained further in Dr. Sahu's report, these variability factors are higher than the corresponding daily and monthly variability factors for high residence time systems.[206] Yet, EPA fails (again) to acknowledge or explain those differences.

[204] Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards - DCN SE8055, at Tbl. 16, Docket ID No. EPA-HQ-OW-2009-0819-8193 (Sept. 2019).
[205] 84 Fed. Reg. at 64,632.
[206] EPA, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, at Tbl. 13-4, Docket ID No. EPA-HQ-OW-2009-0819-6432 (Sept. 2015) ("2015 TDD").

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 57

Comment Excerpt:

Fifth, although EPA includes a chart summarizing the pilot test results for five low residence time reduction systems, the agency refused to identify those facilities or disclose the underlying effluent tests, claiming that data is confidential business information. As a result, there is no publicly-available support for EPA's conclusory assertions that similarly-situated steam facilities can achieve comparable pollution reductions using low and high residence time reduction technologies. There is no valid basis for withholding from public review the results of effluent monitoring on which EPA is relying to form the basis for nationally-applicable, industry-wide effluent standards. The Clean Water Act mandates that EPA make available to the public "any" records applicable to any applicable effluent limitations, toxic, pretreatment, or new source performance standards, unless the information would divulge methods or processes entitled to protection as trade secrets.[207] Although it is plausible that certain site-specific design, operational, or vendor information could be confidential, there is no valid basis for withholding the actual effluent monitoring data associated with the system.

Without that information, neither the court nor the public have any meaningful ability to evaluate the veracity of EPA's assertion that low and high residence time reduction systems are comparable or achieve similar reductions. Moreover, EPA's "bald assertions" that low and high residence time systems are "comparable" is not sufficient to affirm EPA's proposed BAT determination.[208]

[207] 33 U.S.C. § 1318.
[208] See, e.g., *Luminant Generation Co. v. EPA*, 675 F.3d 917, 925 (5th Cir. 2012) (rejecting EPA's "passing" and "unsupported" assertions that final action was based on the relevant requirements of the Act); *Texas v. EPA*, 690 F.3d 670, 678 (5th Cir. 2012) (in reviewing a Clean Air Act implementation plan, the court "requires more than the [agency's] bare conclusion"); *La. Envtl. Action Network v. EPA*, 382 F.3d 575, 586–87 (5th Cir. 2004) (rejecting EPA's "naked assertion[s]" and remanding the agency's approval of a Louisiana Clean Air Act plan because agency "fail[ed] to mention or show any evidence" to support its conclusions); see also In re *Bell Petroleum Servs., Inc. v. Sequa Corp.*, 3 F.3d 889, 905 (5th Cir. 1993) ("[j]udicial review 'must be based on something more than trust and faith" in the agency's assertions) (internal citations omitted)).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 58

Comment Excerpt:

Sixth, EPA concedes that low residence time systems "occasionally may discharge at a level that is higher."[209] – i.e., they result in pollution spikes but fails to explain how long-term average pollution reductions adequately protect against short-term spikes in pollution levels that may harm human and aquatic health. Short-term exposure to selenium, for example, can cause damage to the peripheral nervous system; and selenium is acutely poisonous to fish and other aquatic life in even small doses; concentrations below three to eight µg/L can kill fish, and lower concentrations can leave fish deformed or sterile.[210] Mercury is highly toxic in small quantities. Selenium and mercury also bio-accumulate and interfere with fish reproduction, meaning that it can permanently destroy wildlife populations in lakes and rivers as it works its way through the ecosystem over a period of years. Even accepting EPA's unsupported assertion that long-term pollutant concentrations are comparable between low and high residence time reduction systems, EPA fails to explain how low residence time systems make further reasonable further progress toward eliminating short-term pollution impacts that harm humans and aquatic life. The Clean Water Act requires BAT limits that the "maximum resources economically possible to the ultimate goal of eliminating all polluting discharges"[211] – not just assuring long-term discharge rates that are comparable. EPA concedes that low residence time systems may result in high variability of pollutant discharges, yet the agency fails to explain how its proposed BAT determination adequately protects against short-term pollution spikes.

By its very nature, a shorter residence time means that there is less room for error. If FGD wastewater is treated for only 1-4 hours for low residence systems (compared to 10-16 hours for high residence systems), there is simply less time for pollutants to filter or settle out of the wastestream. Nothing in the 2019 Proposal or the TDD grapples with that fundamental issue. Moreover, EPA's 2015 TDD suggests that a biological treatment system's residence time is a critical variable in the efficacy of the technology. In 2015, or example, EPA observed that biological systems need a "sufficiently long residence time" to ensure removal of pollutants like selenium and nitrate/nitrite.[212] Moreover, biological systems "typically require" fine tuning and optimization of residence times and other variables to function properly.[213] EPA's low residence time BAT proposal does not address those issues, or explain how its one-size-fits-all proposal will ensure necessary pollution reductions on a continuous basis.

Moreover, as noted above, the record reflects only four examples of full-scale low residence time systems,[214] and EPA does not provide *any* data that allows for a meaningful comparison between the pollution reductions achievable with low and high residence time systems. As a result, it is impossible to determine whether low residence time systems are, in fact, the "best-performing" technology in the field, as required for any BAT determination under the Act.[215]

[209] 84 Fed. Reg. at 64,661.
[210] See, e.g., EPA, Steam Electric Power Generating Point Source Category: Final Detailed Study Report, at 6-4, Docket ID No. EPA-HQ-OW-2009-0819-0387 (Oct. 2009); 2015 EA at 3-4 tbl. 3-1.
[211] *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980).
[212] 2015 TDD at 8-5; see also id. at 7-12 ("The bioreactor system typically contains multiple bioreactor cells. For example, the Duke Energy Carolinas' Allen Steam Station and Belews Creek Steam Station have two stages of bioreactor cells in series, as shown in Figure 7-3, but both stages of bioreactors contain multiple cells in parallel. Plants usually require multiple bioreactors to provide the necessary residence time to achieve the specified removals.").
[213] Id. at 13-2 to 13-3.
[214] Proposed TDD at 4-3.
[215] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 226 (5th Cir. 1989) ("Congress intended these [BAT] limitations to be based on the performance of the single best-performing plant in an industrial field."); see also *Nat. Res.*

Defense Council v. EPA, 863 F.2d 1420, 1426 (9th Cir. 1988); *Kennecott*, 780 F.2d at 448 ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible."); cf. *Riverkeeper, Inc. v. EPA*, 475 F.3d 83, 107-08 (2d Cir. 2007) ("The statutory directive requiring facilities to adopt the best technology cannot be construed to permit a facility to take measures that produce second-best results . . . especially given the technology-forcing imperative behind the Act. . . .") (citations omitted), rev'd on other grounds sub nom. *Entergy Corp. v. Riverkeeper, Inc*., 556 U.S. 208 (2009).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 61

Comment Excerpt:

Finally, setting aside EPA's arbitrary refusal to explain or demonstrate that low residence time technology is, in fact, the Best Available Technology, the record makes clear that EPA's proposal to walk back its 2015 BAT determination is impermissibly and exclusively based on cost. Indeed, the primary driver in EPA's reversal is that low residence time systems are "less costly" and "less complex" than high residence time systems, saving the industry approximately $72 million annually, while resulting in "comparable," although more variable pollution concentrations.[216] EPA then attempts to justify the potential for pollution spikes and higher variability in pollution concentrations by arguing that "EPA would disserve its mandate were it to tilt at windmills by imposing BAT limitations which removed de minimis amounts of polluting agents from our nation's waters . . . ."[217]

But that facile argument crystalizes the flaws in EPA's approach. As an initial matter, Congress determined that investments in pollution controls are warranted to the greatest degree possible, and therefore the inquiry is not whether the costs of a given control are "worth it" in EPA's estimation.[218] Instead, EPA must select the best performing, economically achievable technology as BAT.

[216] 84 Fed. Reg. at 64,631-32.
[217] Id. at 64,632, n.20 (quoting *Am. Petroleum Inst. v. EPA*, 787 F.2d 965, 972 (5th Cir. 1986)).
[218] See, e.g., *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1052 n.54 (D.C. Cir. 1978) ("a cost-benefit analysis is not required at all" for BAT); *CPC Int'l Inc. v. Train*, 540 F.3d 1329, 1341-42 (8th Cir. 1976) (BAT guidelines are "governed by a standard of reasonableness without the necessity of a thorough cost-benefit analysis"); *Reynolds Metals Co v. EPA*, 760 F.2d 549, 565 (4th Cir. 1985) ("no balancing is required" for BAT); *Rybachek v. EPA*, 904 F.2d at 1290-91 (EPA "need not compare [control] cost with the benefits of effluent reduction"); *BP Exploration & Oil, Inc. v. EPA*, 66 F.3d 784, 799-800 (6th Cir. 1995) (rejecting industry demand for cost-benefit analysis because BAT "does not require cost-benefit analysis" and "EPA need only find … that the cost of the technology is reasonable"); *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) (underlining that "BAT is the CWA's most stringent standard" and must be set based not on cost-benefit analysis but on "the performance of the single, best-performing plant in an industrial field"); *Waterkeeper All. v. EPA*, 399 F.3d at 516 (BAT can be set to the level which can "reasonably be borne by a given industry"); *Am. Paper Inst. v. Train,* 543 F.2d 328, 348 (D.C. Cir. 1976) ("Section 304(b)(2)(B) mandates no such [cost-benefit] balancing for the 1983 limitations"); *Ass'n of Pac. Fisheries*, 615 F.2d at 805 ("The conspicuous absence of the

comparative language contained in section 304(b)(1)(B) leads us to the conclusion that Congress did not intend the Agency or this court to engage in marginal cost-benefit comparisons [for BAT].").

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 62

Comment Excerpt:

Here, there is no dispute that high residence time systems are widely available, effective, and economically achievable.

Moreover, although the court in *American Petroleum* recognized that there may be a point at which it would be unreasonable to impose BAT limitations to remove *de minimis* amounts of pollution, the court concluded that EPA had not reached that point, even where the BAT limits at issue regulated "trace" amounts of mercury and cadmium.[219] In any case, it is impossible to characterize the difference between pollution reductions achieved by low and high residence time systems as *de minimus*. In addition, EPA does not even disclose what that difference actually is, let alone address the potential that use of low residence time systems would result in short-term pollution spikes as compared to high residence time systems. EPA's conclusory assertions that low and high residence time reduction systems achieve "comparable" pollution levels are not sufficient to support the agency's action.[220]

In sum, EPA has a legal obligation to require the best-performing technology as BAT, if the technology is available and economically achievable.[221] Both the 2015 rule and the current proposal recognize that chemical precipitation followed by high residence time reduction biological treatment is achievable, available, and would substantially reduce levels of mercury, arsenic, selenium, and nitrates. EPA fails to demonstrate that its proposal to establish low residence time reduction technology as BAT will achieve the same pollution reductions or make reasonable progress toward eliminating all discharges. In fact, the agency fails to provide any non-confidential support for this portion of the 2019 Proposal. Instead, the record makes clear that EPA's proposal to walk back its 2015 BAT determination is impermissibly and exclusively based on cost, and is therefore arbitrary, capricious, and contrary to law.

[219] *Am. Petroleum Inst.,* 787 F.2d at 972.
[220] *Luminant Generation Co. v. EPA*, 675 F.3d 917, 925 (5th Cir. 2012).
[221] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 226 ("Congress intended these [BAT] limitations to be based on the performance of the single best-performing plant in an industrial field.").

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 21

Comment Excerpt:

(ii) EPA's clear preference for LRTR biological treatment systems for reducing nitrate/nitrite and selenium, as opposed to the previous BAT of HRTR systems appears to be based entirely on the fact that LRTR systems are cheaper than HRTR systems, and this is not supported in the record. From my review of the record, EPA presumes that these two options are equally capable of meeting the 2015 ELG standards for FGD wastewater, and therefore the cheaper LRTR systems are preferable. I disagree and discuss this in Section 3. Regardless, this is a moot point given that the record compels EPA to acknowledge that systems that achieve ZLD of FGD wastewater are widely available;

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 28

Comment Excerpt:

3.2 LRTR and HRTR

Before I do so, it is worth noting, that the HRTR and LRTR distinctions are not defined accordingly to any commonly accepted standards. EPA discusses the differences as follows:

LRTR System. A biological treatment system that targets removal of selenium and nitrate/nitrite using fixed-film bioreactors in smaller, more compact reaction vessels than those used in the biological treatment system evaluated in the 2015 rule (referred to in this proposal as HRTR—high residence time biological reduction). The LRTR system is designed to operate with a shorter residence time (on the order of 1 to 4 hours, as compared to a residence time of 10–16 hours for HRTR), while still achieving significant removal of selenium and nitrate/nitrite. The LRTR technology option considered as part of this proposed rule includes chemical precipitation as a pretreatment stage prior to the bioreactor and ultrafiltration as a polishing step following the bioreactor.[89]

Additional but similar discussion is provided in the TDD accompanying the 2019 proposed rule in Section 4 (pages 4-2 and 4-3) and, for HRTR in the 2015 TDD in Section 7.1.3. As these discussions make clear, these are not separate technologies. While there are hydraulic retention time differences, those are and can be functions of individual vendor designs – i.e., there is no industry standard that defines the demarcation between HRTR and LRTR in terms of hydraulic retention time. The same technology can function as "high residence" or "low residence," it is simply a matter of how it is operated.

89 84 Fed. Reg. at 64,627

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 30

Comment Excerpt:

Despite this clear weakening of the selenium BAT limits between the 2015 Final rule and the 2019 proposal—which is over three times less stringent – from 23 ug/L to 76 ug/L – for the daily maximum and a little less than three times less stringent – from 12 ug/L to 31 ug/L – for the monthly—EPA mischaracterizes and glosses over these dramatic reductions in its various statements accompanying the proposed rule:

- First, in its summary, EPA simply acknowledges that it is proposing a "relaxation"[90] of the selenium limitation for FGD wastewater without any hint of the large decrease in stringency I have summarized above;
- More egregiously, EPA simply mischaracterizes the dramatic differences between the HRTR and LRTR system capabilities (both accompanied by CP) when it says "LRTR reductions are comparable to HRTR reductions,"91 when the data simply shows that that is not the case. Note that in the summary above, the LTA (i.e., even before daily and monthly variability is considered) is 7.4 ug/L for HRTR and 16.6 ug/L for LRTR – showing clearly the far worse performance of LRTR as compared to HRTR even on a long term basis. This is not surprising given that the LRTR systems are designed to be cheaper and one cannot therefore expect them to be as effective. Nowhere in the record does EPA acknowledge this reality or offer any technical reason why HRTR systems are unavailable;
- EPA then asserts "…while the effluent from LRTR is more variable than HRTR, both technologies achieve long-term average effluent concentrations for selenium lower than 20 mg/L"[92] Even without the typographical error (i.e., EPA meant 20 ug/L as opposed to 20 mg/L), this statement is unclear and unsupported. EPA does not offer any rationale, and I am not aware of any technical basis, for choosing a 20 ug/L threshold, other than to select a number that is higher than the long-term average for both HRTR (at 7.5 ug/L) and LRTR (at 16.6 ug/L), thereby masking the fact that the LTA for HRTR is less than half that of LRTR. EPA continues: "As explained in Section XIII of this preamble, the long-term averages forming the basis of the selenium limitations for LRTR and HRTR are similar, and the higher selenium limitations for the LRTR systems are largely driven by increased short-term variability around that average, rather than a meaningful difference in long- term pollutant removals (footnote omitted)."[93] But the LTA data clearly show that HRTR and LRTR are not similar. Indeed, the LTA for LRTR (7.5 ug/L) is more than double HRTR's LTA (16.6 ug/L). EPA is correct that LRTR's worse performance is compounded by additional variability – but not just in the short-term (i.e., daily maximums) as it states – this variability is also worse in the monthly averages. I discuss this below. EPA acknowledges the less-effective performance of LRTR compared to HRTR when it states: "The EPA's objective in establishing daily maximum limitations is to restrict the discharges on a daily basis at a level that is achievable for a facility that designs and operates its treatment to <u>achieve the long-term average</u>

> performance that the EPA's statistical analyses show the BAT/PSES technology can attain (i.e., the mean of the underlying statistical distribution of daily effluent values)…Targeting treatment to achieve the daily limitation, rather than the long-term average, is not consistent with the capability of the BAT/PSES technology basis…"[94] (emphasis added). Since the LTA for LRTR is 16.6 ug/L while that for HRTR is 7.5 ug/L, as I have noted above, it is clear that LRTR cannot consistently "attain" the same performance level as HRTR.

That LRTR is less effective than HRTR should not be a surprise. A longer residence time provides more time for the system to remove pollutants. What is surprising is EPA's attempt to portray this less effective option as being the same as the more robust, HRTR option. Clearly BAT should be based on the more effective option. Again, as my prior comments note, BAT for FGD wastewater should simply be zero discharge.

90 84 Fed. Reg. at 64,620.
91 84 Fed. Reg. at 64,631.
92 Id. at 64,631 n.19.
93 Id. at 64,631.
94 Id. at 64,661.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 31

Comment Excerpt:

3.4 Variability of LRTR

As the summary Table 3-1 shown earlier confirms, not only the LTA but, in addition, the daily and monthly variability factors of LRTR are far worse than HRTR (shown in Table 13-4 of the 2015 TDD) This summary is confirmed when one looks at the actual underlying LRTR data EPA used in arriving at its 76 ug/L (daily) and 31 ug/L (monthly) limits in the 2019 proposed rule. I have excerpted below, just that portion of Table 16 from EPA's Supplemental Statistical Support Document[95], used to support the proposed limits.

Table 16. Plant-specific long-term average and variability factors, option long-term average and variability factors, and limits for selenium (µg/L) in LRTR final effluent

Baseline Adjusted[1]	Autocorrelation Value[2]	TYPE	N[3]	Plant Name	LTA	Daily Variability Factor	Monthly Variability Factor	Limits	
								Daily	Monthly
0	0	Plant-Specific	73 (D=35, ND=38)	2019	18.603	4.905	1.911		
			8 (D=8, ND=0)	2027	16.430	4.898	1.944		
			75 (D=27, ND=48)	2066	7.698	4.536	1.794		
			44 (D=6, ND=38)	2090	12.829	4.878	1.882		
			46 (D=45, ND=1)	2097	26.733	2.958	1.524		
		Option			16.430	4.435	1.811	72.870	29.753
	0.66	Plant-Specific	73 (D=35, ND=38)	2019	18.722	4.999	1.963		
			8 (D=8, ND=0)	2027	16.612	4.995	1.994		
			75 (D=27, ND=48)	2066	7.711	4.566	1.828		
			44 (D=6, ND=38)	2090	12.912	5.076	1.956		
			46 (D=45, ND=1)	2097	26.813	2.989	1.551		
		Option			16.612	4.525	1.858	75.168	30.869

EPA used LRTR pilot test data from 5 plants (noted as plants 2019, 2027, 2066, 2090, and 2097 in order to protect CBI data). The wide variability in even the LTAs – from 7.711 to 26.813 ug/L - from these 5 plants is clearly shown. While the lowest of these values is comparable to the HRTR LTA, all of the other 4 data sets show much larger LTAs from the LRTR pilot tests. The data above also show the dramatically higher daily (ranging from 2.989 to 5.076) and monthly (ranging from 1.551 to 1.994) variability factors. These are higher than the corresponding HRTR daily and monthly variability factors supporting the 2015 Rule, as shown in the table in Table 13-4 of the 2015 TDD, excerpted above. The HRTR daily variability factors ranged from 2.779 to 2.873 and the monthly variability factors ranged from 1.480 to 1.492. These are, in each case, significantly smaller than the LRTR daily and monthly variability factors.

In summary, the performance of LRTR is notably worse than HRTR, per EPA's own data. While LRTR may be cheaper than HRTR,[96] there is a definite and pronounced loss of performance that accompanies this cheaper cost across any time scale, including i.e., long term, monthly, and daily. EPA, by highlighting just the cheaper cost, but improperly glossing over (and misleading) LRTR's performance, improperly arrives at much weaker limits for selenium.

95 See EPA, Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards (Sept. 2019) (EPA-HQ-OW-2009-0819-8193).
96 Since much of the cost data accompanying the 2019 proposed rule is CBI, I could not conduct a meaningful review of this data. I will note, however, that certain costs have not been included in EPA's analysis for LRTR. Important among this is cost for equalization, an important requirement for LRTR. I have carefully reviewed the

TDD (Section 5.2.3 and 5-3) discussion on CP+LRTR. I did not see any adequate inclusion for equalization, other than a vague note of "storage tanks" whose purpose is not clear.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 25

Comment Excerpt:

c. At the very least, EPA must retain high residence time biological treatment as BAT—it cannot reverse course and set a lesser technology as BAT.

At the very least, EPA must retain chemical precipitation plus high residence time biological treatment as BAT. As the Fifth Circuit has held, "BAT limitations must be based on the performance of the single-best performing plant in an industrial field."[40] Duke Energy has demonstrated that using high-residence time biological treatment as the technological basis for pollution limits is both available and economically achievable. In North Carolina, Duke Energy has been operating high residence time bioreactors—General Electric's ABMet system—at Belews Creek, Allen, and Roxboro for more than a decade. The technology was available then, and it is available now. GE is a large international company with the scale and resources to provide the technology and support needed to achieve ELG compliance. Contractors have significant experience deploying the ABMet system in North Carolina and could deploy it more widely in North Carolina and across the Southeast.

The argument that it would be "tilting at windmills" to set BAT based on high-residence time rather than low-residence time is both factually and legally wrong. Factually, the differences EPA proposes in selenium limits, both monthly and daily, are not de minimis—EPA proposes to triple the amount of pollution allowed by the 2015 Rule.

It is particularly important to have controls truly based on the best available technology given the well-established harms of selenium contamination.

[40] *Sw. Elec. Power Co.*, 920 F.3d at 1006; see also *Kennecott*, 780 F.2d at 448 ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible.") (citing A Legislative History of the Water Pollution Control Act Amendments of 1972, 93d Cong., 1st Sess. (Comm. Print 1973), at 798).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 50

Comment Excerpt:

B. Chemical Precipitation Plus High Residence Time Reduction Systems Are Readily Available and Achievable and Meet the BAT Standard.

EPA must adopt effluent limitations for FGD wastewater that reflect the “Best Available Technology.” As noted above in Sections II – Legal Background and III – Southwestern Electric, BAT must be the best available technology that is economically achievable[179]—that is, “economically possible to the ultimate goal of eliminating all polluting discharges.”[180] A technology is “available” if it is in use in the industry,[181] and it is economically achievable if the costs can be reasonably borne by the industry as a whole.[182] Moreover, “in assessing BAT, total cost is no longer to be considered in comparison to effluent reduction benefits.”[183] Thus, the inquiry is not whether any additional cost is “worth it,” but whether the technology makes reasonable further progress toward eliminating all pollution discharges.[184]

EPA concedes that chemical precipitation followed by high residence time reduction technology is technologically available and economically achievable.[185] Indeed, this combination was the basis for EPA’s 2015 BAT determination.[186] The 2015 record and EPA’s proposal make clear that the addition of biological treatment, following chemical precipitation, is a very well established technology to treat FGD wastewater, and results in substantial reductions in selenium and nitrate/nitrate levels as well as reductions of mercury and arsenic, above and beyond chemical precipitation alone.[187] In its 2019 proposal, EPA identifies at least five steam electric facilities with wet scrubbers that currently have full-scale chemical precipitation and high residence time reduction systems and several others with similar types of biological treatment systems to reduce selenium and nitrate/nitrite pollution in addition to mercury and arsenic.[188] And EPA concedes that several of those full-scale systems have used the biological technology to treat FGD wastewater for more than a decade under varying operating conditions, climate conditions, and coal sources.[189] In short, there is no serious dispute that chemical precipitation followed by high residence time reduction systems are available, economically achievable and result in significant pollution reductions of mercury, arsenic, selenium, and nitrate/nitrite pollution.

Despite this record, industry continues to argue that biological treatment systems are infeasible due to fluctuations in influent characteristics due to the type of coal burned at different EGUs and cycling of certain coal units. For the reasons set out in the 2019 Proposal[190] and our comments on the 2013 proposed rule and 2017 Postponement Rule and attached technical reports,[191] we agree with EPA that the available data makes clear that chemical precipitation followed by high residence time reduction technology is available and economically achievable.

Although EPA concedes that high residence time reduction systems are available and in use in the industry, economically achievable, and highly effective in removing selenium and nitrate/nitrite pollution (in addition to residual mercury and arsenic pollution),[192] the agency does not even include high residence time systems as a BAT option. Instead, the agency baldly asserts that low residence time reduction systems are less costly, “comparable” in their ability to reduce pollution, and require fewer process or facility modifications.[193] That cursory explanation is arbitrary and capricious, for several reasons.

First, EPA's refusal to even consider a technology that is demonstrably available is arbitrary and capricious, and contrary to the Clean Water Act. In selecting BAT, EPA has an obligation to consider and meaningfully evaluate technologies that are, in fact, available and in use in the industry.[194] A technology need not even be in commercial use to be available, so long as the technology has been studied and demonstrated, such as through the use of pilot studies.[195] Although EPA concedes that its 2015 rule was based on the use of high residence time reduction technology, the agency arbitrarily and unlawfully fails to provide any explanation for even considering it as an option now.[196] The technology has not somehow become unavailable four years later, nor is there any basis in the record for EPA to claim otherwise.

[179] 33 U.S.C. § 1311(b)(2)(B).
[180] *EPA v. Nat'l Crushed Stone Ass'n,* 449 U.S. 64, 74 (1980); see also *Nat. Res. Def. Council v. EPA*, 808 F.3d 556, 563-64 (2d Cir. 2015) (the BAT standard is meant "to be technology-forcing, meaning it should force agencies and permit applicants to adopt technologies that achieve the greatest reductions in pollution.").
[181] See *Chem. Mfrs. Ass'n v. EPA,* 870 F.2d 177, 226 (5th Cir. 1989); *Am. Petroleum Inst.*, 858 F.2d at 265; *Kennecott v. EPA*, 780 F.2d 445, 448 (4th Cir. 1985).
[182] *Waterkeeper Alliance, Inc. v. EPA*, 399 F.3d 486, 516 (2d Cir. 2005); *Rybachek v. EPA*, 904 F.2d 1276, 1290-91 (9th Cir. 1990).
[183] *EPA v. Nat'l Crushed Stone*, 449 U.S. 64, 71 (1980); see also *Am. Iron & Steel*, 526 F.2d 1027, 1051-52 (3rd Cir. 1975) ("With respect to the [BAT] standards," Congress intended "that there should be no cost-benefit analysis.").
[184] *Sw. Elec. Power Co.*, 920 F.3d at 1016.
[185] See, e.g., 84 Fed. Reg. at 64,631.
[186] Id. at 64,627.
[187] This process has also been used to reduce selenium and other metals in many other industries, including: drainage water from irrigated agriculture, mining wastewater, metals processing wastewaters, and oil refinery wastewaters. Jenkins FGD Report, Appendix C to Comments of Environmental Integrity Project et al., at 4, Docket ID No. EPA-HQ-OW-2009-0819-4702 (Sept. 20, 2013).
[188] Proposed TDD at 4-2; 84 Fed. Reg. at 64,631; see also FGD Treatment In Place Memorandum – DCN E07092, Doc. EPA-HQ-OW-2009-0819-7807. Of these fifteen facilities, nine are currently operating anoxic/anaerobic biological treatment (either high or low residence time reduction) designed to substantially reduce nitrogen compounds and selenium in their FGD wastewater. The others use other types of biological systems that can remove nitrogen and selenium. 84 Fed. Reg. at 64,631.
[189] Id.
[190] Id.
[191] Comments of Sierra Club et al., Docket ID No. EPA-HQ-OW-2009-0819-6654, at 27-32 (July 6, 2017); Comments of Environmental Integrity Project et al., Docket ID No. EPA-HQ-OW-2009-0819-4684, at 29-30 (Sept. 20, 2013).
[192] 84 Fed. Reg. at 64,627.
[193] Id. at 64,631.
[194] *See Am. Petroleum Inst. v. EPA*, 858 F.2d 261, 265 (5th Cir. 1988); FMC Corp. v. Train, 539 F.2d 973, 983-84 (4th Cir. 1976) (finding EPA justified in setting BAT for chemical oxygen demand based on performance data from a single pilot plant).
[195] *See Am. Petroleum Inst. v. EPA*, 858 F.2d 261, 265 (5th Cir. 1988) (stating that under BAT, "a process is deemed 'available' even if it is not in use at all"); FMC Corp. v. Train, 539 F.2d 973, 983-84 (4th Cir 1976) (finding EPA justified in setting BAT for chemical oxygen demand based on performance data from a single pilot plant).
[196] *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) ("[T]he requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it is changing position. An agency may not, for example, depart from a prior policy sub silentio or simply disregard rules that are still on the books." (emphasis in original)).

16 FGD Wastewater – CP + HRTR

No comment excerpts were received on this topic.

17 FGD Wastewater – Membrane Filtration

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 8

Comment Excerpt:

Key Comments on FGD VIP Technical Feasibility

The proposed FGD VIP technologies have several significant operational limitations. The proposed limits on treated FGD wastewater under the VIP option may not be achievable for all power plants employing the membrane filtration plus encapsulation approach.

- Pretreatment is critical for attaining/maintaining reliable operation of membrane-based systems and can represent a significant and majority portion of the total cost of a system.
- A challenge in deploying membrane technology is the management of concentrated brine and the solid waste generated by the membrane and pretreatment systems. System design requires balancing clean water (i.e., permeate) recovery, permeate quality, treatment costs, and waste management costs.
- EPA should use the same technology basis to develop membrane treatment costs and numerical effluent limitations. For cost estimating, EPA assumed either no pretreatment or pretreatment using microfiltration only; but in setting limits, EPA used pilot tests that included pretreatment of solids removal (and in some cases, chemical treatment) upstream of membrane treatment.
- Advanced membrane filtration plus encapsulation technologies alone cannot consistently meet the proposed numeric limits.
- The datasets provided for consideration by EPA include data above both the daily maximum and monthly average proposed numeric limits; however, the data used for setting VIP limits are based on limited datasets.
- EPA's rationale for excluding two datasets should be made clear.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 26

Comment Excerpt:

4. **FGD WASTEWATER VIP TREATMENT COSTS**

EPRI evaluated several types of treatment that may potentially be used to meet the proposed FGD VIP limits. We understand that the EPA used "advanced membrane filtration" technologies [EPA, 2019a] which are designed to treat high total dissolved solids (TDS) and total suspended solids (TSS) wastestreams and reduce the scaling and fouling of membranes that make traditional spiral-wound reverse osmosis (RO) membranes problematic for FGD wastewater [EPA, 2019c]. However, these advanced membrane technologies have little to no full-scale application experience treating FGD wastewater. EPRI evaluated several membrane and thermal technology options.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 34

Comment Excerpt:

FGD VIP TECHNICAL FEASIBILITY

5.1 **Technical challenges**

Installation of any water treatment technology, including membrane systems, requires consideration of membrane treatment (including pretreatment) and waste/residuals management requirements. EPRI has provided a brief description of key technical challenges surrounding membrane treatment and encapsulation in Comments 5.1.1 and 5.1.2. For a more complete description of the challenges and important considerations for these technologies, EPRI suggests reviewing *Considerations for Treating Flue Gas Desulfurization Wastewater Using Membrane and Paste Encapsulation Technologies* [EPRI, 2019], which is publicly available to review for no cost and has been provided as an attachment with EPRI's comments.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 54

Comment Excerpt:

XIV. The VIP Option: Commercial Application of Membranes and Paste Encapsulation to Treat FGD Wastewater Is Not Technologically Available.

In the Proposal, EPA concludes that the record does not support establishing BAT limits based on membrane filtration because it is not technologically available nationwide at this time, but may become available by 2028. See 84 Fed. Reg. at 64,632. UWAG agrees with EPA's conclusion that the record does not support setting BAT limits based on membrane filtration, but finds that significantly more research and demonstration are needed at the commercial scale to determine whether membrane filtration and/or paste encapsulation is technically feasible. It may never be available nationwide due to insurmountable obstacles at certain facilities.

Membrane technologies use microporous or nonporous materials to selectively separate various pollutants from water. Microporous membranes (e.g., microfiltration and ultrafiltration) rely on the size of each pore for separation, whereas nonporous membranes (e.g., reverse osmosis and forward osmosis) rely on separation at the molecular level based on the solubility and diffusivity of each pollutant. Limited research exists for applying membrane technology to treat FGD wastewater. Moreover, one key obstacle to implementing membrane technology is the management of concentrated brine and solid waste generated by the process. In some circumstances, facilities heat the residual brine until all of the water evaporates and only the crystallized solids remain (i.e., thermal evaporation).[74] Then, the solids are disposed in an onsite landfill or transferred offsite by truck or train for disposal in an offsite landfill. This is an expensive process, due to the thermal energy required to produce evaporation and the cost of removing and disposing the solids. Furthermore, once the solids have been placed in the landfill, in some cases, their properties are such that their long-term stability is not yet demonstrated. For example, a landfill in Orlando, Florida, experienced landfill liner degradation problems once FGD solids were added.[75] The strong leachate was incompatible with the landfill's geocomposite liner. Even with special equipment or procedures, the ability to stabilize salts in a landfill for the long-term is questionable.

Paste encapsulation—another emerging technology—seeks to address these issues by chemically stabilizing and physically sequestering pollutants derived from FGD wastewater into a material that not only will retain the pollutants over the long-term but also provides for efficient transportation to a disposal site. By adding certain chemical compounds and mixing the wastewater with solid binders, such as fly ash, the wastewater can be converted into a flowable solid material that can be pumped at high velocity to the disposal site where it hardens in place.

While membrane technologies have been used by coal-fired power plants to produce highly purified or demineralized water for the boiler/steam cycle and to treat cooling tower blowdown for reuse and/or discharge, they have not been used within the United States to treat FGD wastewater.[76] The only reported commercial application of a membrane-based system is in China. According to the administrative record for the Proposal, EPA is aware of three facilities in China that apparently have installed membrane filtration systems.[77] However, there is little publicly available information about these facilities, EPA does not have information on the longterm performance of these systems or how the resultant brine is managed, and Oasys—the company that developed the forward osmosis technology used at two of these plants—has ceased operations.[78] Thus, the Chinese systems do not provide sufficient models for commercial application of membrane technologies in the United States. While EPA has some information about the use of membrane filtration on FGD wastewater from pilot studies, the preamble notes that significant uncertainty remains regarding how the technology would function at the commercial scale. 84 Fed. Reg. at 64,633.

While EPA considers such uncertainty sufficient to support a finding that membrane filtration is not BAT, EPA also indicates that the cost of membrane filtration and the costs associated with disposing of the resulting brine are significantly higher than the proposed BAT option (i.e., chemical precipitation plus Low Hydraulic Residence Time Biological Reduction (CP+LRTR)). *Id*. EPA concluded, however, that such costs do not make membrane technologies "economically unachievable." *Id.* Again, while UWAG agrees with EPA's overall conclusion that membrane technologies are not BAT for all existing sources, UWAG disagrees that such technologies are economically achievable. The comments below provide additional background on the significant challenges associated with the combination of using membranes and paste encapsulation to treat FGD wastewater, including the economic barriers to implementation.

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[74] According to notes in the record, EPA indicated that four facilities have thermal treatment in place. See ERG, *Memorandum re: Notes from Meeting with Earthjustice,* EPA-HQ-OW-2009-0819-7751 (Aug. 23, 2019) at 3.

[75] See Tetra Tech, et al., "Orlando Coal Ash Landfill: A Case History for Designing and Building New Coal Ash Landfills" presented by Mohamad Alhawaree (June 10-11, 2013).

[76] EPRI, *Considerations for Treating Flue Gas Desulfurization Wastewater Using Membrane and Paste Encapsulation Technologies,* No. 3002017134 (Nov. 2019) ("EPRI Membrane Report") at 3-4.

[77] There are two Oasys installations at the Changxing Power Plant and Shanxi Lujin Electric Power's Wangqu Thermal Power Station, and one Suez installation at the Jingneng Zhuozhou power plant.

[78] BlueTech Research, *Comment: Oasys Hits Funding Drought* (Jan. 10, 2018), https://www.bluetechresearch.com/news-blog/comment-oasys-hits-funding-drought/ (last visited Dec. 21, 2019).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 55

Comment Excerpt:

1. Further Research Is Needed Before Adopting These Emerging Technologies.

The combination of using membrane filtration with paste encapsulation is an emerging technology, and further basic research is needed before it is ready for commercial applications. This approach to treating FGD wastewater is not technically feasible at this time.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 56

Comment Excerpt:

a. Membrane Technology

To better understand whether coal-fired power plants can apply these emerging technologies to treat FGD wastewater, a number of areas need to be further explored. First, pretreatment is critical for maintaining the reliable operation of a membrane-based system, because suboptimal pretreatment can lead to fouling[79] and an overall loss of performance, requiring frequent chemical cleaning or replacement. Therefore, additional research is needed to study the impacts of membrane fouling and ways to mitigate such impacts in the short-term. Relatedly, additional research is needed to monitor the long-term performance of membranes under various chemical and operational conditions to determine ideal conditions, rate of deterioration, and replacement frequency, ultimately providing facilities with a better understanding of costs.

More research is also needed to identify the types of oxidants and scalants in FGD wastewater and test ways to prevent membrane degradation. Without a deeper understanding and sufficient data on membrane integrity and membrane life, EPA cannot demonstrate that such technology is BAT. Thus, additional research is necessary to understand the potential costs associated with the projected life expectancy of membrane technologies based on pretreatment, operating conditions, and maintenance care.

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[79] Fouling is a form of membrane contamination where a substance in the wastewater deposits on the surface or in the pores of the membrane.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 63

Comment Excerpt:

d. Costs May Preclude Economic Feasibility at Certain Facilities.

As an emerging technology, there are still critical unknowns that will add further costs. As described above, depending on the results of research, facilities may be subject to additional costs associated with differences in FGD wastewater concentration and chemistry, fly ash type and quantity, and upstream additives. Facilities that currently sell fly ash will likely need to forgo a portion of that revenue to incorporate additional fly ash into the encapsulation mix. Other facilities may not produce enough fly ash during standard operations and will need to purchase supplemental fly ash from an external source. For membrane technologies, significant cost factors include feed water equalization, chemical softening, solids removal, biofouling mitigation and free-chlorine removal, oxidant reduction, pH adjustment and antiscalant, membrane chemical cleaning, membrane treatment systems, and balance of plant systems and equipment. Due to this variability across plants, costs at some facilities will likely be so high that membrane technology would not be economically achievable.

The permeate recovery rate of a membrane system measures the conversion of feed water to permeate over a given period of time. For example, a simplified membrane system operating at 80 percent recovery will convert 80 percent of the influent into treated permeate, with approximately 20 percent generally requiring disposal. Thus, lower recovery causes an increase in brine volume, which must be encapsulated and disposed of, resulting in higher capital costs, higher O&M costs, and additional fly ash requirements.[100] Some facilities may have lower membrane recovery rates due to high chloride and/or TDS in the FGD wastewater, membrane scaling and/or fouling issues, pretreatment system upsets, or frequent membrane flushing. Also, to achieve the proposed VIP limitations for the permeate, a facility would likely need to sacrifice the recovery rate. According to EPRI's calculations, a 30 percent decline in recovery would more than double a facility's total annualized costs, from approximately $40 million per year at roughly 81 percent recovery to $98 million per year at 50 percent recovery.[101] At such facilities, the cost of membranes and paste encapsulation technologies would be much higher than the costs for physical or chemical precipitation plus biological treatment.

Thus, as confirmed by EPRI's calculations, it does not appear that EPA adequately considered the costs of implementing membrane filtration and paste encapsulation technology.

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[100] Id. at 4-7.
[101] Id. at Table 4-2.

Commenter Name: David Martin
Commenter Affiliation: ProChem, Incorporated (Inc.)
Document Control Number: EPA-HQ-OW-2009-0819-8307-A1
Comment Excerpt Number: 1

Comment Excerpt:

Membrane treatment technologies significantly reduce pollutants discharged from FGD waters and can be a part of a zero liquid discharge strategy to eliminate contaminants from being discharged to water ways. Membrane systems can be added to the end of the conventional precipitation system to significantly reduce pollutants discharged or even eliminate water discharge.

Commenter Name: David Martin
Commenter Affiliation: ProChem, Incorporated (Inc.)
Document Control Number: EPA-HQ-OW-2009-0819-8307-A1
Comment Excerpt Number: 2

Comment Excerpt:

The advantages of membrane treatment over the low hydraulic residence time biological treatment include:

- A greater than 90% reduction in Total Dissolved Solids (TDS) discharged. Most applications reduced FGD TDS from 16,000+ mg/l to < 200 mg/l.
- Additional contaminants removed as the membranes reject dissolved solids. The dissolved solids removed include the FGD regulated contaminants plus Sodium, Chlorides, Bromides, Boron, as well as many other dissolved solids not yet regulated. The removal of the TDS leads to a much cleaner discharge than any other technology evaluated as well as zero liquid discharge potential.

Commenter Name: David Martin
Commenter Affiliation: ProChem, Incorporated (Inc.)
Document Control Number: EPA-HQ-OW-2009-0819-8307-A1
Comment Excerpt Number: 3

Comment Excerpt:

The advantages of membrane treatment over the low hydraulic residence time biological treatment include:

- Membrane systems can easily be started and shut down and operated as needed. This can be ideal for facilities that are not base load facilities.

Commenter Name: David Martin
Commenter Affiliation: ProChem, Incorporated (Inc.)
Document Control Number: EPA-HQ-OW-2009-0819-8307-A1
Comment Excerpt Number: 6

Comment Excerpt:

Additionally on page 44, “the EPA could not conclude that membrane filtration is technologically available nationwide at this time” Currently I-PRO systems are operational in NC, OR, TX, NY, VA, KY and SC showing they are available and operational in industrial applications nationwide.

Commenter Name: David Martin
Commenter Affiliation: ProChem, Incorporated (Inc.)
Document Control Number: EPA-HQ-OW-2009-0819-8307-A1
Comment Excerpt Number: 7

Comment Excerpt:

The proposed rule indicates that EPC firms with no vested interest in the technology are hesitant to recommend that a client become the first site in the US to adopt membrane filtration for the treatment of FGD wastewater due to the uncertainty of the system performance and frequent if not excessive chemical cleaning. FGD wastewater is just an industrial wastewater, no different than cement siding manufacturer's wastewater. EPC firms are recommending older technologies that discharge more pollutants to our water ways than newer technologies that discharge fewer pollutants. Regarding the reference to "excessive" chemical cleaning; clean water generated from the membrane process (membrane permeate) is used to flush the membranes to minimize chemical cleanings. The chemical cleanings are part of the overall concentrate generated which is < 10% of the incoming untreated wastewater, leaving >90% purified water from FGD blowdown.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 36

Comment Excerpt:

5.1.2 **A challenge in deploying membrane technology is the management of concentrated brine and the solid waste generated by the membrane and pretreatment systems. System design requires balancing clean water (i.e., permeate) recovery, permeate quality, treatment costs, and waste management costs.**

A challenge in deploying membrane technologies is the management of concentrated brine and solid waste generated by the membrane and pretreatment systems. When designing a membrane system, there should be a balance between clean water recovery, clean water quality, treatment costs and waste management costs. Designing for high-quality clean water (i.e., permeate) will increase the wastewater/brine/concentrate generated and solid waste production. As not every site will always be able to reuse water, the design of the membrane system will need to accommodate producing permeate that can comply with the proposed discharge numeric limitations (when required) along with onsite reuse applications.

When considering wastewater encapsulation approaches, there are often short-term physical and chemical properties of the material that are desired (e.g., subjecting a material to a toxicity characteristic leaching.

Procedure (TCLP) test (specifically, Method 1311). These properties should not be confused with or necessarily considered a proxy for meeting a site's long-term wastewater encapsulation goals (e.g., prediction of a site's long-term leachate generation and chemistry). Encapsulation research to-date relies on cement hydration chemistry, whereby plants would need to provide sufficient moisture for chemical reactions to fully proceed, but not excess free water (which is water in the system above what can be chemically incorporated into hydration reactions). In practice, the exact liquid-to-solid ratios as well as the type and amount of additive required are site-dependent and could change over time as ingredient material properties change, of which, research is all currently short term.

Plants considering encapsulation may confront several technical challenges, such as:

- **Effects of Wastewater Chemistry:** Although chemical softening pretreatment will mitigate membrane scaling, little encapsulation research has been conducted on wastewaters that could result from a wastewater treatment system where chemical softening has taken place (that is, wastewater primarily in the form of sodium-based compounds).
- **Effects of Wastewater Concentration:** The wastewater concentration being considered for encapsulation will likely influence the cost for volume reduction, fly ash availability, and encapsulation additive costs. It is expected that volume reduction technologies (that is, membrane and/or thermal treatment systems) will be needed to reduce wastewater volume to an extent that encapsulation could be an option. Multiple stages of volume reduction technologies may be required for some plants.
- **Effects of Water Treatment Chemical Additives:** To date, little research has been conducted on how chemical additives required for upstream membrane systems (for example, membrane chemical cleaning waste) will impact encapsulation chemistry. Acids, surfactants,salts, sugars, and scale-inhibiting chemicals are all known to impact the setting and hardening behavior within concrete.
- **Effects of Fly Ash Type and Quality:** The type of fly ash available at a site can have a wide range of impacts on both technical and economic factors. For most Class F fly ashes (that is, Illinois Basin and other eastern bituminous coals) that are pozzolanic but not self-cementing, alkaline additives, such as quicklime or cement, will be required for encapsulation chemical reactions to proceed. Class C fly ash (that is, subbituminous, low-sulfur western fuels) tends to have a high fraction of native calcium and is often self-cementing; therefore, fewer additives are needed. However, the Class C materials can pose material-handling challenges, such as setting too quickly.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 57

Comment Excerpt:

b. Paste Encapsulation Technology

As noted above, there are few proven, cost-effective methods for disposing the concentrated waste streams produced by FGD systems. Paste encapsulation is one process that is being evaluated; however, similar to the membrane technologies, it is also an emerging technology, and little research has been conducted on how it would apply at the commercial scale. One must consider the amount of fly ash available to be used for encapsulation, as well as the volume of wastewater to be sequestered (i.e., a site's material balance), how the encapsulated material will be mixed, transported, and placed, and whether the landfill can be managed to ensure long term stability.

As identified in EPRI's Membrane Report, there are a number of areas that require additional research to determine whether paste encapsulation technology provides a feasible approach to treating FGD wastewater. For example, most wastewater encapsulation relies on cement hydration chemistry, in that typical hydration reactions observed in concrete also typically occur in encapsulation systems. However, in a paste system, a higher moisture content might be favorable to optimize permeability. In practice, the specific liquid-to-solid ratios and the type and amount of additive required depends on the site and could change over time due to fluctuations in temperature or brine content. Therefore, EPRI recommends that expanded research be conducted to include more chemistries and time-based results and to evaluate longterm encapsulation properties.[80]

Also, to date, EPRI's research on FGD wastewater encapsulation has focused on systems where the wastewater is principally composed of alkaline earth metals like calcium and magnesium; however, little research has been conducted on systems where chemical softening has been deployed, creating sodium-based compounds. In such cases, isolation of the salts is based solely on physical solidification, rather than chemical stabilization. Thus, the implications of chemical softening and its downstream effects on safe disposal should be explored further.[81] EPRI's report notes other research needs that should also be explored prior to any federal requirement to implement paste encapsulation technologies.

More data are also needed on the long-term behavior of encapsulated material. While research has been conducted at the laboratory scale, most of the current physical and environmental property data is for material cured for 90 days or less, and field testing at the demonstration scale has only just begun.[82] For example, for the first time, enough concentrated brine was made available to facilitate encapsulation testing in the fall of 2018.[83] These studies will provide greater understanding of the hydraulic properties of these materials under exposure to environmental conditions and the quality of runoff and leachate water at the disposal site. Accordingly, long-term monitoring will be critical to understanding the long-term behavior of encapsulated material.

[80] EPRI Membrane Report at 15.
[81] Id.
[82] *See* Kirk Ellison, *Landfill Sequestration of Brine: Research Updates,* 2019 World of Coal Ash Conference, May 13-16, 2019, EPRI, Palo Alto, CA.
[83] Id

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 58

Comment Excerpt:

2. Membrane and Paste Encapsulation Technologies Present Other Challenges.

Beyond the extensive research recommended by EPRI, there are indications that other problems with membrane and paste encapsulation technologies may need to be addressed prior to commercial application. To produce an encapsulation mix with the correct consistency, a facility must mix the liquid waste with a specific amount of fly ash. Facilities that burn eastern bituminous coals that contain higher chloride content would need to use a significant amount of produced fly ash in the encapsulation process to have effective liquid-to-solid ratios.[84] At many facilities, however, the volume of FGD wastewater would exceed the mass of fly ash available for the mix, in part because the availability of fly ash could be dictated by competitive beneficial uses.[85] For example, facilities that sell fly ash likely do not have a sufficient supply to solidify the brine. For these facilities, the volume of wastewater must be reduced by employing closed cycle operations or using thermal evaporation technologies, either alone or in combination with importing fly ash. Thus, the availability of fly ash can have a major impact on how much wastewater can be encapsulated.

In addition, due to a number of issues, the technical feasibility and economic achievability of landfilling the encapsulated paste will depend on site-specific factors. The distance between the mixing area and the disposal site, as well as the desired long-term properties of the paste, will dictate the initial paste viscosity. Once disposed in a landfill, the paste would have a very low infiltration rate, and, when commingled with coal combustion residuals that have a higher infiltration rate, it would create layers of impenetrable barriers. Similar to what occurred at the King George County Landfill site in Virginia, this could prevent drainage from reaching the leachate collection system and cause a blowout. See 84 Fed. Reg. at 64,633. Thus, to prevent this type of layering and a potential failure of the landfill's containment system, it is necessary to segregate low infiltration rate encapsulated brine in a landfill cell separate from higher infiltration wastes; however, such dedicated cells do not exist today and would require significant time and costs to obtain approval and construct. There also may be regulatory challenges in gaining approval for disposal of the encapsulated paste in the landfill for a number of reasons including waste compatibility concerns, compaction requirements, and the potential for free liquids in the landfill prior to curing of the encapsulated paste.

[84] EPRI Membrane Report at 15.

[85] In the preamble to the Proposed Rule, EPA also expressed concern that establishing membranes as BAT would discourage more valuable forms of beneficial reuse of fly ash, such as replacing cement in concrete, which could potentially lead to more fly ash in wastes being disposed. See 84 Fed. Reg. at 64,633.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 25

Comment Excerpt:

2. Further research is needed to address the unknowns, challenges, and risks associated with brine management/paste encapsulation.

Significant additional research needs to be completed before volume reduction and paste encapsulation can be considered a viable technology for management of FGD wastewater.
In addition to any testing related to volume reduction technologies, laboratory-scale research is needed to optimize fly ash paste encapsulation recipes, including the ability to manage fly ash setting and early strength development as well as long-term properties. Other laboratory research is needed to further understand fly ash paste minerology and help prove that the long-term behavior of paste is suitable. Pilot-scale research is needed to prove fly ash paste encapsulation plants will operate as expected, including confirming they will be able to manage FGD concentrate and ash of varying qualities over long production runs. Material compatibility between solidified brine and landfill liners also has not been established.

Southern Company continues to research paste encapsulation technology with the goal of developing sufficient information to determine if volume reduction and paste encapsulation could be used as an alternative to other technologies for treatment of FGD wastewater in the future. Other research needs include:

- Optimizing ash paste encapsulation recipes;
- Understanding long-term leaching behavior of solidified brine;
- Evaluating deposition, material compatibility and landfill stability issues around pastes; and
- Addressing challenges associated with laboratory-to-pilot-to-commercial scaling.

These challenges, considered individually and collectively, confirm membrane filtration technologies with paste encapsulation are not BAT and add significant uncertainty to the proposed belief that they will be commercially available to the industry in 2028.

Commenter Name: David Martin
Commenter Affiliation: ProChem, Incorporated (Inc.)
Document Control Number: EPA-HQ-OW-2009-0819-8307-A1
Comment Excerpt Number: 4

Comment Excerpt:

The downside of membrane-based treatment approach is the management of the brine or concentrate created by the purification system. On page 44 in the proposed regulations, there are statements regarding the brine management as a non-water quality impacts that the EPA finds unacceptable. The EPA based that statement on the solidification (encapsulation) process which is one of many processes that can be utilized to manage the brine. Numerous studies of fly ash humidification with the brine have been conducted. Throughout the proposed rule there are arguments against membrane treatment technologies due to the costs of not only the membrane system but also the costs of fly ash encapsulation. Fly ash humidification for selling and beneficial reuse or disposal was not evaluated. The fly ash humidified with brine can be sold for beneficial reuse or can be disposed meeting all disposal requirements. Additionally, smaller flow facilities (<150 GPM) may benefit from hauling off the concentrate to a CWT as part of a ZLD strategy without additional on-site treatment systems. Additional studies are being conducted regarding fly ash humidification during upcoming treatment studies and pilot tests.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 27

Comment Excerpt:

4. Membrane filtration with paste encapsulation is not technologically feasible or economically achievable at every facility and may never be.

EPA correctly rejected membranes as BAT for all existing facilities, in part, "because it could discourage more valuable forms of beneficial reuse of [fly ash] (such as replacing Portland cement in concrete)." [46] Operating costs from lost ash sales and the additional costs of disposal of the mixed ash-brine solids can outweigh the benefits of paste encapsulation for certain facilities. If membrane technologies are determined to be BAT, some facilities that currently sell fly ash may be forced to forego a portion of ash sales revenue to incorporate additional fly ash into the encapsulation mix. Other facilities, such as those burning higher chloride coals, may not produce enough fly ash during standard operations and will need to purchase additional fly ash from an external source. These issues need to be more thoroughly considered and resolved prior to identifying (or prospectively declaring) membrane filtration and paste encapsulation treatment technologies as BAT.

EPRI developed a case study, summarizing some of the site-specific challenges and costs associated with treating FGD wastewater using membrane technologies with paste encapsulation.[47] The case study describes use of paste encapsulation at a generic power plant producing 300 gpm of wastewater with a maximum achievable permeate recovery estimated at 81%.[48] However, due to variability in coals used at the facility, permeate recovery can be much lower. Lower recovery means higher volumes of brine requiring disposal. The case study plant generated an estimated 198,000 tons of fly ash generation per year. [49] EPRI estimated that if the resulting brines are solidified (paste encapsulation), roughly 309,000 tons per year of fly ash would be required, with the hypothetical power plant having to purchase ash to make up this difference. [50]

Ash availability and price will be variable going forward as coal generation declines, and some plants may not be able to purchase ash at all. In general, sites burning eastern fuels will require more ash for solidification than they produce because the chloride content of the fuel requires a greater FGD purge rate to maintain reasonable chloride levels in the scrubber system for material compatibility.

Disposal of brine solidified with ash could also present challenges for certain facilities. This solids mixture will need to be disposed of in a landfill either on-site or off-site. Not all plants will have the necessary land to build on-site landfills capable of managing these wastes. Moreover, not all plants will have access to off-site landfills equipped to handle these wastes. Furthermore, it may be best to place solids produced from paste encapsulation at some facilities in a landfill distinct from landfills used to currently dispose of coal combustion residuals ("CCR") materials because of the very low infiltration rate associated with the paste material.

EPA has correctly concluded membrane filtration and paste encapsulation is not BAT for the industry. The agency's decision is well-supported by the record. Southern Company strongly encourages EPA to eliminate any prospective declaration that this—or any—technology will be BAT for the industry at some future date. There is no support for this assertion, and Southern Company's comments highlight the considerable research and development still left to be done before anyone can make a fully informed decision regarding whether this technology can feasibly treat FGD wastewater generated by the entire industry.

46 Proposed Rule, 84 Fed. Reg. at 64,633.
47 See Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 4-1 to 4-2, app. D.
48 See id. at 4-1 to 4-2, D-12.
49 See id. at D-3.
50 See id. at D-12.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 4

Comment Excerpt:

Specifically, EPA should:

…

- Establish voluntary incentive program limits as proposed for FGD wastewater using membrane filtration as the technology basis for these limits, as well as the compliance deadline of December 31, 2028;

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 25

Comment Excerpt:

VII. The Proposed Revisions To The Voluntary Incentive Program Are Appropriate; Membrane Filtration Is Not BAT.

One of the goals of the CWA is the elimination of discharges of pollutants into the nation's waters. 33 U.S.C. § 1251(a)(1). In the 2015 rule, EPA finalized a VIP that allowed additional compliance time for plants that choose to adopt additional process changes and controls that will provide significant environmental protections beyond those that would be achieved by the limits established as BAT, and further advance the goal of eliminating discharges of pollutants into the nation's waters. In reconsidering the limits for FGD wastewater, EPA proposes to revise the VIP from the 2015 rule to establish membrane filtration as the technology basis with limits for mercury, arsenic, selenium, nitrate/nitrite, bromide, and TDS for FGD wastewater. EPA also proposes to revise the compliance date for sources that opt to enter the VIP to December 31, 2028. See 84 Fed. Reg. at 64,642.

EPA's overall intentions regarding the use of the VIP are sound, but concerns remain regarding the technical feasibility of the BAT numeric limits using membrane technology at this time. In contrast to the proposed technology basis for BAT for FGD—chemical precipitation followed by a low hydraulic residence time biological treatment including ultrafiltration—membrane filtration technology does not currently represent the best economically available control technology performance for steam electric generating units. In addition to the increased cost of membrane filtration, there remains additional research, engineering, and pilot testing of these technologies—as discussed, supra—which includes the need to determine how best to handle the disposal of the membrane paste. These challenges would need to be addressed before membrane technology could consistently be used to comply with the VIP discharge limits. Once incorporated into NPDES permits, EPA expects that VIP limits, like the limits established when applying BAT, must generally be met by units at all times and under all operating conditions.[23] See 84 Fed. Reg. at 64,662. Therefore, EPA should finalize the VIP limits using membrane filtration as the technology basis for these limits, as well as the compliance deadline of December 31, 2028.

[23] The installation, testing and optimization of membrane technologies will likely require significant amounts of time for units choosing this option. Units opting to install and optimize membrane technologies will be able to access significant environmental benefits, despite the longer time horizon for implementation of control technologies.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 5

Comment Excerpt:

NRECA agrees with EPA's conclusion that membranes and paste encapsulation and thermal evaporation are not BAT for FGDW. The technologies are evolving and, as such, are reasonable candidates for evaluation for the proposed "voluntary incentive program" (VIP) which we also support. The additional time provided under the VIP program will encourage the continued development of additional treatment technologies.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 8

Comment Excerpt:

TVA supports not selecting membrane+ encapsulation (M+E) technologies similar to the voluntary incentive program (VIP) as best available technology economically achievable (BAT) for FGD discharges. TVA agrees there are unknown operational considerations such as membrane replacement frequency that could have a negative effect on system reliability and O&M. In addition, TVA markets as much coal combustion residuals (CCRs) as practicable in order to minimize landfilling of CCR.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 3

Comment Excerpt:

<u>EPA Correctly states Membrane Filtration is not Best Available Technology</u>

In reconsidering the limits for FGD wastewater, EPA proposes to revise the Voluntary Incentive Program (VIP) from the 2015 ELG Rule and instead establish membrane filtration as the technology basis with limits for mercury, arsenic, selenium, nitrate/nitrite, bromide, and total dissolved solids (TDS) for FGD wastewater. EPA also proposes to revise the compliance date for sources that opt to enter the VIP to December 31, 2028.[5] EPA correctly determines that membrane filtration technology does not currently represent BAT for FGD wastewater to derive and impose national limits. These advanced membrane technologies have little to no full-scale operational experience treating FGD wastewater. The viability of membrane treatment technology and subsequent residual and waste management is also highly dependent on site-specific characteristics and factors.[6] Site-specific pilot tests are crucial in evaluating membrane technology and managing the resulting concentrated stream and solid waste. There remains additional research, engineering, and pilot testing of these technologies to evaluate technical feasibility, including pretreatment and waste/residuals management, in addition to understanding the full cost of the system, before this technology could be considered BAT for FGD wastewater.

Furthermore, membrane filtration with nanofiltration or reverse osmosis results in a concentrated brine stream that must be managed, which poses its own site-specific risk and technical feasibility and has yet to be demonstrated in full-scale operation. Research is being conducted on brine paste encapsulation, mainly producing a cementitious product, but technical challenges remain, including:

- Availability of Fly Ash: Encapsulation mixtures requires the use of fly ash. As the capacity factor of coal-fired generation continues to decline, the availability of fly ash may be limited, thus limiting the ability to encapsulate the brine concentrate generated. The type and availability will be highly site-specific and must be evaluated on a site by site basis, not on a national level.
- Landfill Implications: Encapsulation does not resolve potential landfill leachate concerns. Leachate produced will vary in quantity and quality due to multiple factors, such as weather, material landfilled, contact time, amount of active surface area in the landfill, etc., especially when concentrating FGD wastewater that is high in chlorides. Studies conducted by the Electric Power Research Institute (EPRI) have demonstrated that monovalent ions, such as sodium and potassium chloride, do not react chemically and contain different bindings in the cements.[7] This may pose a concern for facilities complying with NPDES permits that contain chloride limits or monovalent ions.
- Capital Costs: More robust cost estimates of encapsulation would need to be conducted on a site-by-site basis prior to determining whether it is economically achievable. Each facility has a different geography, available acreage, and installed equipment that can exceed costs estimates outlined in the proposed rule for encapsulation. A more thorough review of the total cost of a membrane plus encapsulation system should be performed prior to establishing any regulatory requirements based on this technology.

5 84 Fed. Reg. 64,672 (Nov. 22, 2019).
6 Electric Power Research Institute. "Considerations for Treating Flue Gas Desulfurization Wastewater Using Membrane and Paste Encapsulation Technologies." 3002017134. November 27, 2019. Available online: https://www.epri.com/#/pages/product/3002017134/?lang=en-US
7 Id.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 9

Comment Excerpt:

V. FGD WASTEWATER VIP OPTION

EPA proposes to revisit the voluntary incentive program (VIP) limitation established in the 2015 rule using membrane filtration as the technology basis. EPA proposes to revise the compliance date for the VIP limitations to December 31, 2028. EPA concluded that the record does not support establishing BAT limits based on membrane filtration since it is not technologically available nationally but may become so by 2028. APPA supports EPA's finding that the technology is not commercially available, however, we believe more research and demonstrations are needed at a commercial scale to determine whether membrane filtration and/or paste encapsulation is technically feasible and available nationwide. Limited research exists for applying membrane technology to treat FGD wastewater. Further, the management of solid waste generated by the process is a significant obstacle. In some circumstances, facilities heat the residual brine until all the water evaporates and only the crystallized solids remain (i.e., thermal evaporation). Then, the solids are disposed of in an onsite landfill or transferred offsite by truck or train for disposal in an offsite landfill. This is an expensive process, due to the thermal energy required to produce evaporation and the cost of removing and disposing the solids. Furthermore, once the solids have been placed in the landfill, in some cases, their properties are such that their long-term stability is not yet demonstrated. Another emerging technology is paste encapsulation. Encapsulation technology seeks to chemically stabilize and separate the pollutants derived from the FGD wastewater in to a stabilized material that can easily be transported.

EPA has some information on the membrane technology installed at three facilities in China and from pilot studies. However, there is little publicly available information about these systems and no information about their long-term performance. Significant uncertainty remains regarding how the technology would operate at commercial scale.[12] These uncertainties support EPA's conclusion that membrane filtration technology is not BAT.

EPA has indicated that membrane filtration technology will cost the industry more than the proposed BAT options for FGD wastewater (i.e., chemical precipitation plus Low Hydraulic Residence Time Biological Reduction (LRTR)).[13] Added to membrane technology costs is the associated disposal cost of the resulting brine. While costs are a separate factor in establishing BAT, EPA's assertion that "these costs do not make the membrane filtration option 'economically unachievable.'" APPA would disagree that these technologies are economically achievable. APPA defers to the comments submitted by UWAG on the challenges associated with using membranes and paste encapsulation to treat FGD wastewater and the economic barriers.

12 84 Fed. Reg at 64,633.
13 Id.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 8

Comment Excerpt:

UWAG agrees with EPA that membranes and paste encapsulation and thermal evaporation are not "best available technology" for FGD wastewater. The combination of membranes and paste encapsulation is an emerging technology, and much further research needs to be done on both elements of this combination. Important questions remain about the performance of various types of membranes and the long-term stability and leaching characteristics of paste made from constituents such as fly ash, lime, and FGD wastewater.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 68

Comment Excerpt:

C. EPA's Voluntary Incentive Program Based on Membranes and Paste Encapsulation Systems Is Appropriate.

The 2015 rule established a VIP that placed limitations on mercury, arsenic, selenium, and TDSs in FGD wastewater based on thermal evaporation technology. See 80 Fed. Reg. at 67,858. Under the 2015 rule, facilities participating in the VIP would have had until December 31, 2023, to comply with the new standard. EPA now proposes to revise the applicability date for the VIP limitations to December 31, 2028, and revise the limitations set in the 2015 rule using membrane filtration as the technology basis. According to EPA, by December 31, 2028, "the membrane filtration technology will be available nationwide … for those facilities who choose to adopt it." 84 Fed. Reg. at 64,637.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 10

Comment Excerpt:

Voluntary Incentive Program ("VIP")

- We agree with EPA's overall conclusion that membrane filtration is not BAT for FGD wastewater, but we do not agree that this technology will be available in 2028. More research and demonstration of the technology are needed at the commercial scale to determine whether this technology is technically feasible.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.

Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 23

Comment Excerpt:

D. Membranes and Paste Encapsulation to Treat FGD Wastewater are Not BAT, nor Will They be in 2028.

Southern Company supports the inclusion of the VIP option but disagrees that membranes and paste encapsulation to treat FGD wastewater are or ever will be BAT. In the proposed rule, EPA concludes that the record does not support establishing BAT limits based on membrane filtration because it is not technologically available nationwide at this time.[39] However, EPA asserts that it has "determined that the membrane filtration technology will be available nationwide" on December 31, 2028.[40]

Southern Company agrees membrane filtration is not BAT for FGD wastewater. However, we do not agree that this technology will be available in 2028 and think it is imprudent to make that determination almost nine years in advance. EPA's proposed prediction is not supported. Southern Company believes significant research is left to be done and that demonstration of this technology at commercial scale is needed prior to determining it will be technically feasible. Even if it is feasible, it may never be available nationwide due to site-specific constraints.

39 See Proposed Rule, 84 Fed. Reg. at 64,632.
40 Id. at 64,637.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 24

Comment Excerpt:

1. The use of membranes to treat FGD wastewater is an emerging technology.

Membrane technologies utilize microporous or nonporous materials to selectively separate pollutants from water. The limited testing conducted to date on this technological option gives reason for optimism, but significant additional research is needed to establish membrane technologies as an effective and economical means to treat FGD wastewater for the entire industry. Even with significant technological advances in the future, it is unlikely membrane filtration technologies can be implemented at all sites for the reasons explained in subsection 4 below.

Presently, there are no commercial-grade membrane technology systems available for treating FGD wastewater and limited data available from pilot-scale systems. Two of the systems in China cited by EPA in the proposed rule[41] were provided by a vendor that is no longer in business. The osmosis technology utilized in these systems is not currently offered by any other vendor. Other membrane technologies currently marketed for treatment of FGD wastewater use nanofiltration, but there is not a single commercial-scale system currently in service for the treatment of FGD wastewater.[42]

The following is a high-level overview of research Southern Company believes must be completed to better understand the capabilities and limitations of membrane filtration technologies:

- Pretreatment: This step is critical for optimal performance of the membrane systems. Poor pretreatment can lead to membrane fouling and decrease overall treatment performance. Increased knowledge on how to optimize and tailor pretreatment to varying conditions is imperative.
- Operational variability: More needs to be known about how membranes perform in the short- and long-term to various chemical and operational conditions, including cycling unit/plant operational profiles. These results could inform the optimal membrane design.
- Maintenance: Membrane cleaning, rate of deterioration, and replacement frequency must all be studied to have a better grasp on how to maintain system performance and to understand the true costs associated with the technology.

Until this important research is conducted, the technology cannot reasonably be classified as BAT—now or for the future.

41 See id. at 64,632.
42 Id. at 64,633 ("[T]hird-party EPC firms with no vested interest in [membrane filtration] technology are hesitant to recommend that a client be the first site in the U.S. to adopt membrane filtration for the treatment of FGD wastewater because of uncertainty related to system performance and the ability to operate successfully without frequent, if not excessive, chemical cleaning.").

Commenter Name: Michael P. Alaimo
Commenter Affiliation: Clean Fuels Michigan, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8305-A1
Comment Excerpt Number: 4

Comment Excerpt:

Weakening of scrubber sludge/Flue gas desulfurization (FGD) wastewater limits is unjustified and EPA record shows they must be strengthened: EPA is also proposing to allow power plants to discharge higher levels of arsenic and selenium in FGD wastewater, based on the use of less robust biological treatment systems. The 2015 standards were based on the use of chemical precipitation plus advanced biological treatment to drastically reduce the amount of metals, selenium, and nutrients in these discharges. Instead of weakening FGD wastewater limits, EPA should require plants to install membrane or equivalent available technology that cost-effectively eliminate metals, selenium, and nutrients, as well as bromide and other total dissolved solids. Bromide present in source water creates treatment challenges for drinking water systems because it reacts with the disinfectant chemicals used to kill harmful pathogens to form carcinogenic disinfectant byproducts. EPA's own record clearly documents the tremendous public health benefits of reducing bromide discharges from power plants, but its proposal lacks any requirement for plants to actually limit bromide discharges. EPA's record also shows that membrane technology to treat FGD wastewater is available and achievable and therefore EPA must require power plants to use it.

Commenter Name: Jennifer Peters, et al.
Commenter Affiliation: Clean Water Action, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8462-A1
Comment Excerpt Number: 2

Comment Excerpt:

Weakening of scrubber sludge/Flue gas desulfurization (FGD) wastewater limits is unjustified and EPA record shows they must be strengthened: EPA is also proposing to allow power plants to discharge higher levels of arsenic and selenium in FGD wastewater, based on the use of less robust biological treatment systems. The 2015 standards were based on the use of chemical precipitation plus advanced biological treatment to drastically reduce the amount of metals, selenium, and nutrients in these discharges. Instead of weakening FGD wastewater limits, EPA should require plants to install membrane or equivalent available technology that cost-effectively eliminate metals, selenium, and nutrients, as well as bromide and other total dissolved solids. Bromide present in source water creates treatment challenges for drinking water systems because it reacts with the disinfectant chemicals used to kill harmful pathogens to form carcinogenic disinfectant byproducts. EPA's own record clearly documents the tremendous public health benefits of reducing bromide discharges from power plants, but its proposal lacks any requirement for plants to actually limit bromide discharges. EPA's record also shows that membrane technology to treat FGD wastewater is available and achievable and therefore EPA must require power plants to use it.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 19

Comment Excerpt:

b. Membrane filtration should be BAT.

EPA must set membrane filtration[12] as BAT because, as EPA's rulemaking record reflects, it is available, economically achievable,[13] better performing, and more beneficial than both high- and low-residence time bioreactors.

1. Membrane filtration is available, as contemplated by the CWA.

The Clean Water Act requires polluters to use the best available technology economically achievable ("BAT") to control and ideally eliminate their discharge of pollutants.[14] Congress made the Act "technology-forcing": technology-based effluent limitations spur innovation in wastewater treatment and control and ensure progress toward the Act's goal of eliminating the discharge of pollutants into navigable waters.[15] "The BAT standard reflects the intention of Congress to use the latest scientific research and technology in setting effluent limits, pushing industries toward the goal of zero discharge as quickly as possible. In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible."[16]

EPA is wrong to determine membrane technology cannot be BAT because it finds it is not currently available nationwide. Courts long have recognized that "best available technology" for existing sources need not be "widely in use" or even have "demonstrated" present availability in the regulated industry. It is enough that the technology be available at some point in the future. "[I]n establishing these [] standards, the Agency may […] even assess technologies that have not been applied as long as the record demonstrates that there is a reasonable basis to believe that the technology will be available by [the deadline for compliance]."[17]

As the Fourth Circuit held: "Progress would be slowed if EPA were invariably limited to treatment schemes already in force at the plants which are the subject of the rulemaking. Congress envisioned the scanning of broader horizons and asked EPA to survey related industries and current research to find technologies which might be used to decrease the discharge of pollutants."[18] "[I]t is clear that Congress did not intend by that phrase ['available technology'] to limit the technology to that which is widely in use."[19]

As these cases set forth, EPA can rely on data from plants using the model technology anywhere in the world. As EPA itself stated in the prior ELG rule: "BAT is intended to reflect the highest performance in the industry, and it may reflect a higher level of performance than is currently being achieved based on technology transferred from a different category or subcategory, bench scale or pilot studies, or foreign plants."[20] EPA can also rely on pilot plant data. "As the House Report [on the Clean Water Act] stated: 'It will be sufficient, for the purpose of setting the level of control under available technology, […] that there is sufficient information and data from a relevant pilot plant or semi-work plant to provide the needed economic and technical justification[.]'").[21] Additionally, courts have found a certain degree of uncertainty about the technology to be acceptable because those technical questions can be resolved by ongoing research, and EPA has a statutory obligation to revise ELGs in light of such future research.[22] Finally, EPA can rely on data from plants using the model technology in entirely different industries, so long as the record demonstrates the technology is transferrable to the regulated industry, and it can be reasonably predicted that the technology would be capable of meeting the effluent standards.[23]

Membrane filtration is obviously available, as shown by EPA's selection of the technology for the Voluntary Incentives Program ("VIP"). Moreover, EPA's record demonstrates membrane technology is in use at three plants in China, and it has been piloted by at least seven plants in the

United States, including at Duke Energy's Belews Creek site in North Carolina.[24] The technology is also in use in other industries. EPA's site visit notes reflect: "According to [Duke Energy], the paste encapsulation technology is well-proven over the past several decades in the mining industry for tailings deposition and underground backfill."[25] Not only is membrane filtration available, but it can be implemented sooner than 2028. EPA's record shows a membrane filtration system can be implemented within anywhere between 12 months and 28 months.[26] Accordingly, membrane technology is "available," as Courts have interpreted the term to mean under the Clean Water Act and should be used as BAT.

[12] For the purpose of these comments, the term "membrane filtration" means technology, including nanofiltration, reverse osmosis, forward osmosis, and electrodialysis reversal (EDR) membranes, that is used to remove a broad range of dissolved pollutants. As EPA explains, membrane filtration also includes ultrafiltration and microfiltration membranes, which are primarily used for removing suspended solids. See 84 Fed. Reg. at 64,632. However, in these comments, the term "membrane filtration," which we recommend as BAT, refers only to technologies that can remove dissolved pollutants. This approach matches how EPA uses the term "membrane filtration" in the rulemaking. See 84 Fed. Reg. at 64,632.
[13] EPA does not dispute membrane technology is economically achievable. See 84 Fed. Reg. at 64,634.
[14] 33 U.S.C. § 1311(b)(2)(A).
[15] *Kennecott v. EPA*, 780 F.2d 445, 448 (4th Cir. 1985); *see also Nat'l Crushed Stone*, 449 U.S. at 74.
[16] *Kennecott*, 780 F.2d at 448 (citing A Legislative History of the Water Pollution Control Act Amendments of 1972, 93d Cong., 1st Sess. (Comm. Print 1973), at 798 (hereinafter "Leg.Hist.")) ("'The distinction between best practicable and best available is intended to reflect the need to press toward increasingly higher levels of control....'" (quoting Leg.Hist. at 170)).
17 *Tanners' Council of Am., Inc. v. Train*, 540 F.2d 1188, 1195 (4th Cir. 1976); see also *FMC Corp. v. Train*, 539 F.2d 973, 983-84 (4th Cir. 1976) (same).
[18] *Kennecott*, 780 F.2d at 453 (citing Leg.Hist. at 170).
[19] *See Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1058 (3d Cir. 1975), amended, 560 F.2d 589 (3d Cir. 1977); see also id. at 1061 (extending its conclusions about BAT for new sources to existing sources).
[20] 80 Fed. Reg. 67,843 (citing *Am. Paper Inst. v. Train*, 543 F.2d 328, 353 (D.C. Cir. 1976); *Am. Frozen Food Inst. v. Train*, 539 F.2d 107, 132 (D.C. Cir. 1976))). Accord *Kennecott*, 780 F.2d at 453 (relying on data from plants in Japan and Sweden).
[21] See *Am. Iron & Steel Inst.*, 526 F.2d at 1058 ("[S]ince we have concluded that reliance on pilot plant technology was proper in establishing limitations for new sources, it should also be proper in establishing [BAT] limitations for existing sources.")
22 See *NRDC v. EPA*, 863 F.2d 1420, 1433 (9th Cir. 1988) (despite EPA's asserted lack of "complete information" on availability of technology, declaring BAT limitation invalid because "Congress has demonstrated its intent to require industry to do as much as possible to control toxic discharges") (citing 33 U.S.C. § 1311(b)(2)(A)(i)); *Tanners' Council*, 540 F.2d at 1195-96 ("There are several technical questions which need to be resolved prior to initiation of full-scale nitrification-denitrification facilities on a tannery waste. However, it is deemed that such questions can be answered by on-going research in other areas and by investigations initiated prior to [the compliance deadline]."); see also Sw. Elec. Power Co., 920 F.3d at 1018-19 (rejecting EPA's BAT rationale that it lacked data).
[23] See *Kennecott*, 780 F.2d at 453 ("The model technology may exist at a plant not within the primary base metals industry. Congress contemplated that EPA might use technology from other industries to establish the Best Available Technology."); Tanners' Council, 540 F.2d at 1192.
[24] See 84 Fed. Reg. at 64,632.
[25] EPA, Notes from Site Visit to Duke Energy's Belews Creek Steam Station on December 13, 2017, Docket ID No. EPA-HQ-OW-2009-0819-7337 ("Belews Creek Site Visit Notes").
[26] See ERG, FGD and Bottom Ash Implementation Timing – DCN SE08480, at 3, Docket ID No. EPA-HQ-OW2009-0819-8191 (Oct. 17, 2019); Email from Greg Johnson, New Logic Research, to Phillip Flanders, Ronald Jordan, and Elizabeth Gentile, Docket ID No. EPA-HQ-OW-2009-0819-8179 (June 22, 2019); KLeeNwater, Budgetary Proposal – Wastewater Treatment & Water Reuse Systems – DCN SE07065A18, at 13, Docket ID No.

EPA-HQ-OW-2009-0819-7617 (Nov. 16, 2017); ERG, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367, at M- 2, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 20

Comment Excerpt:

2. Membrane filtration is demonstrably superior to low-residence time biological treatment.

Courts have held that a technology that is "demonstrably inferior to other available technologies" cannot be considered BAT.[27] "[T]he Supreme Court has explained that a BAT must achieve 'reasonable further progress' towards the Act's goal of eliminating pollution."[28]

As EPA's record shows, membrane filtration is more effective at controlling pollution than low residence time biological treatment.[29] In addition, it is the only technology that can control bromide, aside from a zero liquid discharge system, like the vapor compressor evaporator system at Duke Energy's Mayo facility in North Carolina.[30] It is particularly compelling and urgent for EPA to adopt as BAT the technology that controls bromide, because, as set out below in the section on Bromides, bromide is an FGD pollutant that has significant consequences for public water supplies, local government expenditures, and public health. In North Carolina, even sites with high residence time biological treatment have had difficulty controlling selenium due to variability caused by fuel changes.[31] To address selenium spikes, Duke Energy added ultrafiltration to its treatment systems at Allen and Belews Creek.

[27] *See Sw. Elec. Power Co.*, 920 F.3d at 1019 (rejecting surface impoundments as BAT).
[28] Id. at 1006 (citing *Nat'l Crushed Stone*, 449 U.S. at 75).
[29] See, e.g., 84 Fed. Reg. at 64631 (ultrafilters downstream of biological filters cannot remove the dissolved metals and inorganics (e.g. nutrients, bromides, etc.) that nanofiltration or reverse osmosis can).
[30] Id.
[31] Belews Site Visit Notes, supra n.26; EPA, Variability in Flue Gas Desulfurization Wastewater: Monitoring and Response, Docket ID No. EPA-HQ-OW-2009-0819-6033 (Sept. 30, 2015) ("EPA FGD Variability Memo"); Duke Energy, Summary of the Effects of Fuel on the Performance of the FGD Wastewater Treatment System at Allen and Belews Creek Steam Stations, Docket ID No. EPA-HQ-OW-2009-0819-6033, DCN SE05846A1 (May 22, 2015) ("Duke Energy FGD Variability Memo").

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 21

Comment Excerpt:

Not only is membrane filtration effective at controlling pollution and is therefore a better wastewater treatment system, but the record demonstrates it also has more benefits than low residence time biological treatment. Overall, EPA estimates Option 4, using membrane filtration as BAT, would realize $105.9 million in annualized benefits at three percent discount rate, whereas EPA's preferred Option 2, using low-residence time biological treatment, would achieve $19.6 million—less than one-fifth the benefits of Option 4. The differences in benefits included in EPA's analysis are significant. For example, membrane filtration uses much less water. EPA's preferred Option 2 would use 21 million more gallons of water per year, whereas Option 4 would save 9 million gallons per year over the baseline—creating a 30 million gallon difference between the two options.[32] EPA admits Option 2 is expected to increase water withdrawal from aquifers, whereas membrane filtration would not.[33] Membrane filtration would also achieve nearly double the surface water quality benefits, produce a quarter of the air emissions, and significantly reduce the need for dredging maintenance for both navigable rivers and reservoirs.[34]

[32] See 84 Fed. Reg. at 64,652-53.
[33] See Fed. Reg. at 64,659.
[34] See 84 Fed. Reg. at 64,658-59

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 24

Comment Excerpt:

Instead of looking to the overall benefits of membrane filtration over low-residence time biological treatment, EPA wrongly focuses narrowly on cost to industry, including the opportunity cost of using fly ash to dispose of brine resulting from the membrane filtration process rather than selling it for use in concrete. EPA attempts to cloak this industry concern as an unacceptable non-water quality environmental impact, claiming membrane filtration could "discourage more valuable forms of beneficial reuse of [fly ash]" and "potentially caus[e] more [fly ash] to be incorporated in wastes being disposed."[38] However, this concern is completely speculative. As the record shows, there are other methods of disposing of brine that do not require fly ash. Additionally, only fifty percent of fly ash is currently sold for beneficial use; using fly ash to encapsulate brine will not necessarily reduce the amount of fly ash sold for beneficial use because there is plenty of fly ash to spare.[39] Removing dissolved metals and organics with membrane filtration and disposing of the resulting brine with fly ash in a dry, lined landfill, away from surface water and out of groundwater, benefits the environment far more than discharging those pollutants directly into our waterways, as EPA proposes to do under Option 2. The benefits of membrane filtration outlined above far outweigh EPA's narrow so-called environmental impact—which is really an industry concern about cost—of encapsulating fly ash.

[38] 84 Fed. Reg. at 64,633.
[39] See id.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 31

Comment Excerpt:

VI. THE RECORD BEFORE EPA SHOWS THAT THE AGENCY MUST ADOPT A ZERO-DISCHARGE STANDARD FOR FGD WASTEWATER

EPA is obligated to promulgate limitations that reflect the "Best Available Technology" or BAT. BAT represents the best available technology that is economically achievable, a stringent treatment standard with a specific legal definition. A technology is "available" if it is in use in the industry, even if only by the best-performing plant in the industry, or if it can be demonstrated to be available through pilot studies or its use in other industries.[120] A technology is economically achievable if the "costs can be reasonably borne by the industry."[121] Congress determined that investments in pollution controls are warranted to the greatest degree possible, and therefore the inquiry is not whether the costs of a given control are "worth it" in EPA's estimation. Instead, EPA's determination of economic achievability must be guided by the Supreme Court's holding that BAT limits "represent[] a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges."[122] If a technology capable of eliminating a wastestream is "technologically and economically achievable," then EPA is obligated by the Clean Water Act to require the elimination of that wastestream.[123]

The record for the 2019 Proposal shows that a zero-discharge standard for FGD wastewater is available and achievable. Specifically, EPA concedes that membrane filtration is economically achievable, and the record shows that membrane filtration and other zero-discharge technologies are in use in the industry, and therefore "available." EPA is therefore legally obligated to require the elimination of FGD wastewater.

[120] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 226 (5th Cir. 1989) ("Congress intended these [BAT] limitations to be based on the performance of the single best-performing plant in an industrial field."); see also *Nat. Res. Def. Council, Inc. v. EPA*, 863 F.2d 1420, 1426 (9th Cir. 1988); *Kennecott v. EPA,* 780 F.2d 445, 448 (4th Cir. 1985) ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible."); *Am. Petroleum Inst. v. EPA*, 858 F.2d 261, 265 (5th Cir. 1988) (stating that under BAT, "a process is deemed 'available' even if it is not in use at all"); FMC Corp. v. Train, 539 F.2d 973, 983-84 (4th Cir. 1976) (finding EPA justified in setting BAT for chemical oxygen demand based on performance data from a single pilot plant).
[121] *Waterkeeper All., Inc. v. EPA,* 399 F.3d 486, 516 (2d Cir. 2005); Rybachek v. EPA, 904 F.2d 1276, 1290-91 (9th Cir. 1990) (discussing this standard).
[122] *EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 74 (1980).
[123] 33 U.S.C. § 1311(b)(2)(A).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 32

Comment Excerpt:

A. The Record Before EPA Demonstrates that Membrane Technology or Its Equivalent is BAT for FGD Wastewater

1. Membrane technology is both available and achievable, and clearly meets the BAT standard

a. Membrane filtration is economically achievable

EPA concedes that membrane technology is economically achievable.[124] Indeed, it appears that membrane filtration is the most affordable treatment technology (beyond simple impoundments) for many plants: EPA identified 18 plants for which membrane filtration with compliance in 2028 is cheaper than the technology identified as BAT in the 2019 Proposal (chemical precipitation plus biological treatment).[125] The record also shows 23 plants for which the costs of membrane filtration with compliance in 2028 are even lower than basic chemical precipitation costs. And the record shows 8 plants for which membrane filtration costs are lower than basic chemical precipitation costs even if one assumes immediate compliance (i.e., foregoing the costs savings that accompany waiting until 2028 to install membrane filtration) (see Table below).

Table. Plants for which FGD wastewater treatment using membrane filtration is more affordable than treatment using chemical precipitation, assuming immediate compliance.

Plant	Annualized chemical precipitation costs[126]	Annualized membrane filtration costs[127]
F.B. Culley Generating Station	$1,529,229	$1,470,227
J. K. Spruce Power Plant	$1,246,593	$1,096,656
Lawrence Energy Center	$1,076,531	$857,521
Marion Generating Station	$1,172,714	$1,025,964
Muscatine Power and Water Generating Station	$936,068	$668,842
Plant Hammond	$1,500,683	$1,460,551
R. M. Schahfer Generating Station	$1,356,742	$1,322,151
W. A. Parish E.G.S.	$1,434,686	$1,411,470

The economic achievability of membrane treatment becomes even clearer when one considers the fact that EPA overestimated compliance costs in at least three ways. First, EPA failed to consider options for lower costs by lowering FGD purge rates.[128] Second, EPA used maximum purge rates to estimate costs; plant owners could easily install equalization capacity to handle peak flows and design their FGD treatment systems around lower, average flow rates at lower cost.[129] Third, EPA used outdated (2016) coal usage data when more recent data would show less coal usage and lower purge flows.[130] Given that membrane filtration is economically achievable using EPA's inflated cost estimates, there can be no question the true costs are affordable.

Finally, it is important to note that these cost estimates are for the purchase of FGD wastewater treatment systems. Yet membrane filtration systems and perhaps other technologies can also be leased,[131] which makes them even more affordable for short-term use. EPA must analyze the extent to which leasing makes membrane filtration economically achievable for the units scheduled to retire by 2028.

[124] See, e.g., 84 Fed. Reg. at 64,634 ("[C]osts do not make the membrane filtration option economically unachievable.").
[125] Proposed TDD at 6-15, n.47; EPA, VIP Plant Flags and Analysis Comparing Technology Costs, DCN SE07652, Docket ID No. EPA-HQ-OW-2009-0819-7706 (the "Option 2 VIP Comparison" spreadsheet at this docket number shows lower costs for "FGD Membrane 2028" than for "Option 2 . . . FGD CP + LRTR" for all 18 VIP plants).
[126] Capital cost and annual O&M cost from ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090, tbl. 4, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019). Annualized costs were calculated as [annual O&M costs + ((capital cost*0.07)/(1-(1.07)^-20))]. Recurring costs were not included, but for all of the units shown, the recurring costs were the same (cost savings) under either regulatory option.
[127] Id. at tbl. 7.
[128] See Dr. Ranajit (Ron) Sahu, Technical Comments on EPA's Proposed Rule to Revise the Best Available Technology (BAT) Effluent Limitations Guidelines (ELGs) for Flue Gas Desulfurization (FGD) Wastewater and Bottom Ash Transport Water (BATW), at 23-24 ("Sahu Expert Report") (attached).
[129] Id. at 24.
[130] Id.
[131] See, e.g., ERG, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367, at M-2, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019).

Commenter Name: Thomas Cmar
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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
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b. Membrane filtration is an available technology

Since membrane filtration is economically achievable, the only material question before EPA is whether membrane filtration is "available." The record clearly shows that it is. Membrane filtration has been used to treat FGD wastewater from coal plants in at least twenty-one pilot studies.[132] Pilot studies – even a single pilot study – are enough to establish that a technology is available.[133] The fact that there have been over twenty pilot studies reinforces that membrane filtration is currently available.

Several of the membrane technologies evaluated by EPA are in use in other industries, or on other wastestreams in the steam electric industry. For example, the description of the "BKT FMX Membrane Technology" states that "this system has now been operating in the U.S. for the past ten years."[134] The New Logic VSEP system has been installed to treat cooling tower blowdown at four locations that all appear to be steam electric plants.[135] The Purestream/AVARA system has been running in one location (on an unstated wastestream) for three years.[136]

Finally, membrane filtration appears to be in use by at least one plant for treating FGD wastewater. In the 2019 Proposal, EPA states that it "is not aware of any domestic facilities which have to date installed nanofiltration or reverse osmosis membrane filtration systems to remove dissolved pollutants in FGD wastewater."[137] The record shows otherwise, and identifies at least one permanent installation of a membrane filtration system at a U.S. coal plant. In a June 2019 email, Greg Johnson of New Logic Research said the following:

Regarding our [VSEP membrane] system that was installed at the research center in Atlanta, I can confirm that it is begin [sic] moved to the new location and that it will be a permanent installation to treat about 50 gm of FGD effluent. This is the total flow that they have and this is not intended to be a pilot, it is a final treatment plant that will be permanent.[138]

Although not necessary to establish the availability of membrane filtration, this permanent installation further reinforces the fact that the technology is available. EPA must at the very least evaluate this permanent installation and correct its statements about the absence of domestic installations. EPA must also revise its discussion of "concerns" raised by unnamed sources "about operating a technology . . . that would be the first of its kind in the U.S.,"[139] as those concerns are no longer valid.

In sum, given the numerous pilot studies of membrane filtration of FGD wastewater, the multiple permanent applications to other industries and other wastestreams in the steam electric industry, and at least one permanent installation for treating FGD wastewater in the U.S., there can be no question that membrane filtration is now "available" for purposes of establishing BAT. EPA effectively concedes that membrane filtration is available by assuming that it will be adopted by eighteen plants.[140] The question before EPA is not <u>whether</u> membrane filtration is available – EPA assumes that it is – but rather when it can be installed. We turn to the question of timing in the next section.

[132] See, e.g., id. at Appendix B (describing five pilot studies of the "BKT FMX Membrane Technology"); id. at Appendix I ("EPA has reviewed data for four onsite pilot-scale studies with KLeeNwater at steam electric power plants for FGD wastewater treatment"); id. at Appendix K (describing seven pilot studies of the "New Logic Membrane Technology" on FGD wastewater); id. at Appendix L (describing a pilot study of the "Oasys Forward Osmosis Technology" at Georgia Power's Plant Bowen Power Station); id. at Appendix M (identifying four pilot studies of the "Purestream Membrane Technology" at U.S. coal plants).
[133] *Kennecott v. EPA,* 780 F.2d 445, 448 (4th Cir. 1985) ("In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible."); *Am. Petroleum Inst. v. EPA*, 858 F.2d 261, 265 (5th Cir. 1988) (stating that under BAT, "a process is deemed 'available' even if it is not in use at all"); *FMC Corp. v. Train*, 539 F.2d 973, 983-84 (4th Cir. 1976) (finding EPA justified in setting BAT for chemical oxygen demand based on performance data from a single pilot plant).
[134] ERG, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367, at B-2, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019).
[135] Id. at K-12.
[136] Id. at M-3.
[137] 84 Fed. Reg. at 64,632.
[138] Email from Greg Johnson, New Logic Research, to Phillip Flanders, Ronald Jordan, and Elizabeth Gentile,

Docket ID No. EPA-HQ-OW-2009-0819-8179 (June 22, 2019).
[139] 84 Fed. Reg. at 64,633.
[140] Proposed TDD at 6-15, n.47.

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2. EPA incorrectly assumes that membrane technology cannot be fully implemented until 2028; in fact, membrane systems can be installed much sooner.

The record shows that membrane filtration systems can be installed within twenty-eight months, and in many cases more quickly than that. EPA's contractor ERG cites a "typical" timeline of twenty-eight months.[141] However, this is based on a single bid, and is in fact the longest timeline in the record. The New Logic VSEP system has a timeline of roughly twenty-five months from request for proposal to full operation.[142] The record contains a bid for a KLeeNwater membrane filtration system with a twelve-month timeline.[143] Purestream's AVARA system "can be built in 180 days and is deployable within two days of on-site delivery."[144] In sum, membrane filtration systems can be installed and operational in as little as six months, with twenty-eight months being an outside estimate. For a rule with an effective date of January 2021, compliance could be achieved by 2023. Yet EPA makes the highly dubious claim that membrane filtration will only be available in 2028.[145] None of EPA's arguments in support of this arbitrary compliance date withstand scrutiny.

EPA first argues that it is only aware of seven pilot studies, and no permanent installations, of membrane filtration systems for FGD wastewater.[146] However, as described above, the record actually includes many more pilot studies and at least one permanent installation.

EPA goes on to suggest that it does not have enough information to "analyz[e] the pollutant removal efficacy and effluent variability" associated with membrane filtration systems.[147] This statement is inconsistent, however, with what EPA actually did, which is analyze a set of data from membrane pilot tests and use the data to derive the limitations that it proposes to apply to the VIP plants.[148] At the same time, this argument is also a red herring. The rulemaking record assumes that membrane filtration systems will not have any effluent at all.[149] This directly contradicts EPA's decision to derive non-zero limits for the VIP plants – the BAT limits based on a membrane technology basis should be zero. Consistent with EPA's zero-discharge assumption for membrane systems, there is no need to analyze removal efficacy (if removal will be 100%), and there is no need to analyze effluent variability (if there will be no effluent).

Next, EPA suggests that the use of membrane filtration might interfere with the beneficial use of fly ash because owners will use fly ash to encapsulate the brine produced by the treatment membranes.[150] This is another red herring. To begin with, EPA claims that the median facility with a wet FGD system sells "approximately fifty percent" of its fly ash for beneficial use,[151] implying that it would have less fly ash to sell if it started using fly ash to encapsulate brine. However, EPA does not provide any evidence that brine encapsulation would require so much fly ash that owners would be forced to sell less. In other words, there may very well be enough fly ash in the industry to meet both needs. The record provides no reason to believe that the use of fly ash for encapsulation would have any impact on beneficial use.

Furthermore, encapsulation with fly ash is only one of several available methods for dealing with membrane filtration brine. EPA concedes as much in the preamble,[152] and the record repeatedly confirms the fact that membrane brine can be managed without fly ash. Brine can be crystallized, for example.[153] Or it can be solidified.[154] The record also provides examples of hybrid technological approaches that combine, for example, reverse osmosis and thermal treatment, with first-stage treatment significantly reducing the volume to be treated by a second stage. This approach is already in use for treating cooling tower blowdown in the United States,[155] and in use for treating FGD wastewater in China.[156]

Finally, EPA describes one emerging way of dealing with brine – a "forthcoming paste technology" – and then suggests that its nascent stage of development justifies a compliance date of 2028 for the VIP program.[157] EPA fails to identify this technology with any specificity, and completely fails to explain why it will only be ready in 2028. The record simply does not support EPA's conclusion. Even more problematic is the fact that EPA's conclusion rests on a premise that is obviously false, namely that the "forthcoming paste technology" is the only way of dealing with brine. As described above and in the record, there are many currently available ways of dealing with brine, and there is simply no basis for delayed implementation of membrane filtration.

In sum, membrane filtration is available now, and can be installed and operational within six to twenty-eight months. None of EPA's arguments in favor of delayed compliance withstand scrutiny, and none are supported by the record. EPA must require compliance with a zero-discharge limit on the basis of the availability of membrane filtration (or other technologies)[158] by 2023 at the latest.

[141] See, e.g., ERG, FGD and Bottom Ash Implementation Timing – DCN SE08480, at 3, Docket ID No. EPA-HQ-OW-2009-0819-8191 (Oct. 17, 2019) (showing a "typical timeline" for installing membrane filtration with brine encapsulation of twenty-eight months).
[142] Email from Greg Johnson, New Logic Research, to Phillip Flanders, Ronald Jordan, and Elizabeth Gentile, Docket ID No. EPA-HQ-OW-2009-0819-8179 (June 22, 2019).
[143] KLeeNwater, Budgetary Proposal – Wastewater Treatment & Water Reuse Systems – DCN SE07065A18, at 13, Docket ID No. EPA-HQ-OW-2009-0819-7617 (Nov. 16, 2017).
[144] ERG, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367, at M- 2, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019).
[145] 84 Fed. Reg. at 64,632-33, n.28.
[146] Id. at 64,632.
[147] Id. at 64,632-33.
[148] Proposed TDD at 8-12; 84 Fed. Reg. at 64,674.
[149] Proposed TDD at 6-15, n.47 ("Where the annualized cost for membrane filtration is less than the other regulatory options, the EPA assumed the plant will install membrane treatment <u>and estimated zero post-compliance loadings")</u> (emphasis added). See also ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019) (showing pollution loads of zero for all FGD wastestreams treated with membrane filtration).

[150] 84 Fed. Reg. at 64,633.
[151] Id.
[152] Id. ("[T]here are several alternative ways to treat or dispose of the brine generated by membrane filtration").
[153] See, e.g., ERG, Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367, at B-2, L-3, Docket ID No. EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019).
[154] See, e.g., id. at I-2, I-5, K-2.
[155] Id. at A-3 and I-2. See also id. at B-2 ("Treating FGD wastewater with the FMX system can also be used to achieve significant volume reduction upstream of thermal or solidification zero discharge technologies")
[156] Proposed TDD at 4-5 ("At this plant, the brine undergoes thermal treatment to produce a crystallized salt which is sold for industrial use").
[157] 84 Fed. Reg. at 64,637.
[158] EPA acknowledges that at least three plants are already operating evaporation systems capable of achieving zero discharge, and the Agency assumes that these plants will in fact achieve zero discharge under any regulatory option. ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090, tbls. 3-7, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019) (showing that the Mayo, Merrimack, and Petersburg plants are already using evaporation systems); id. at tbls. 13-17 (showing zero pollution load for these plants under all regulatory options).

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Comment Excerpt:

C. The Clean Water Act Requires EPA to Adopt a Zero-Discharge Standard for FGD Wastewater Because the Technology to do so is Available and Achievable.

According to EPA, membrane filtration systems have no pollution load.[162] The Proposed TDD states that "[p]lants installing membrane filtration are estimated to have zero post-compliance loadings because these plants are likely to reuse treatment system effluent (i.e., membrane permeate) within the FGD scrubber system, rather than discharge and monitor this effluent stream."[163] The fact that membrane filtration meets the definition of BAT and has no pollution load means that EPA can and must require the elimination of FGD wastewater.

[162] Proposed TDD at 6-15, n.47. ("Where the annualized cost for membrane filtration is less than the other regulatory options, the EPA assumed the plant will install membrane treatment <u>and estimated zero post-compliance loadings</u>") (emphasis added). See also ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019) (showing pollution loads of zero for all FGD wastestreams treated with membrane filtration).
[163] Proposed TDD at 6-10.

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
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The record shows that the Best Available Technology for FGD wastewater is membrane filtration.[414] There is no question that the technical "availability" of this technology is the same for the proposed subcategory as it is for the industry as a whole – since the availability of a technology can be demonstrated by showing that it is in use in another industry,[415] the fact that membrane filtration is available for some coal-fired power plants means that it is also available for EPA's proposed subcategory of power plants. The "economic achievability" of membrane filtration is also the same for the proposed subcategory as it is for the industry as a whole: Figures LU1 and LU2 above show that with Option 4, under which most plants would adopt membrane filtration, costs for low-utilization plants are not substantially higher than costs for other plants. If EPA looks at what it purports to be concerned about – capacity factor – there is even less of an issue. Costs for plants that run at a low capacity factor are no different than costs for other plants (Figures LU3 and LU4 above). EPA concedes that membrane filtration is economically achievable for the industry as a whole;[416] since the costs for low-utilization or low-capacity factor plants are not fundamentally different, membrane filtration is achievable for these plants as well.

In any case, EPA has simply failed to provide any evidence that membrane filtration costs for the low-utilization plants could not be "reasonably borne" by those entities, which means that EPA has failed to show that the costs are unachievable.[417] Since membrane filtration is available and achievable for the so-called "low-utilization" plants, it is the Best Available Technology, and there is no need for a subcategory.

[414] See Section VI – Zero Discharge FGD.
[415] *Kennecott,* 780 F.2d at 453 ("Progress would be slowed if EPA were invariably limited to treatment schemes already in force at the plants which are the subject of the rulemaking."); see also *Reynolds Metals Co. v. EPA*, 760 F.2d 549, 562 (4th Cir. 1985).
[416] 84 Fed. Reg. at 64,634 ("[C]osts do not make the membrane filtration option economically unachievable.").
[417] *Waterkeeper All., Inc. v. EPA,* 399 F.3d 489, 516 (2d Cir. 2005); *Rybachek v. EPA*, 904 F.2d 1276, 1290-91 (9th Cir. 1990) (discussing this standard).

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Comment Excerpt Number: 27

Comment Excerpt:

2.4.2 Membrane Technologies

I will now discuss membrane technologies, which EPA describes in its rulemaking record but then curiously backs away from in its proposal. EPA states that such technologies may become mature in 2028, roughly 8 years from today. The documentation provided in the docket directly refutes the idea that more time is needed for membrane technologies to treat FGD wastewater. It is my opinion that membrane technology is available today (and has been available for a few years now) and has been sufficiently demonstrated technically that it can and should also be the basis for a ZLD BAT standard. While thermal technologies and spray dryers can also achieve zero discharge, it is likely that in most applications, membrane-based solutions will be cheaper option to achieve zero discharge.

It is clear from EPA's own research and discussions with various vendors as reflected in the record that there are numerous versions of membrane technologies that can and have been applied to treat FGD purge waste water at coal plants. [64] As EPA has summarized in the TDD:

Membrane filtration has been piloted for FGD wastewater treatment at some plants in the steam electric power generating industry. The EPA spoke with several vendors that have tested the technology in the past and are actively pursuing additional testing. The EPA also identified three plants in China that have installed membrane filtration systems to treat FGD wastewater. Two of the plants employ pretreatment and a combination of RO and forward osmosis. The EPA does not have information on how the brine is handled at these two plants. The third plant operates pretreatment followed by nanofiltration and RO. At this plant, the brine undergoes thermal treatment to produce a crystallized salt which is sold for industrial use. [65]

I agree that membrane technologies cannot by themselves eliminate FGD wastewater. Rather, with reasonable pre-treatment (which may also reduce FGD wastewater volume) and posttreatment – including conversion of the reject "brine" into solid form,[66] there are many permutations and combinations that can lead to ZLD, depending on a plant's specific circumstances.

I should also note that membrane technologies create a reusable water stream (the permeate) that can often be directly reused in the FGD as make-up water or even in the steam cycle (i.e., in the boiler feedwater). In its cost analysis, EPA does not quantify this benefit for membrane technologies, which can be considerable.

EPA itself assumes that membranes, as part of a pre- and post-treatment train can be operated in a way that eliminates wastewater.[67] In short, even though membrane filters by themselves do not eliminate FGD wastewater, membrane systems can – and EPA assumes that they will – be operated in a way that results in zero discharge.

I have carefully reviewed the docket materials relating to membrane technology providers including all of the non-CBI materials relating to EPA's meetings with individual vendors and their presentations, data on pilot projects, etc. I have also carefully reviewed EPA's technology summary memorandum.[68] EPA conducted discussions with at least 4 membrane technology vendors.[69] These include, in no particular order:

(i) **KLeeNwater**, [70] which provided EPA information on at least four successful[71] pilot plant studies including at the Conemaugh power plant and two other unnamed power plants in South Carolina and Indiana, and various bench-scale studies.[72] KLeeNwater also conducted a robust solidification study demonstrating that its brine reject can be successfully solidified using fly ash, gypsum, and other materials – suitable for disposal in non-hazardous landfills.[73] KLeeNwater also provided EPA with several bids it had provided to power plant operators (via their engineering consultants) for installation of its modular systems (typically 250 gpm) at these plants – in 2017.74 Finally, KLeeNwater indicated to EPA that it could take approximately 12-14 months to fabricate and install full scale systems.

In short, KLeeNwater's membrane treatment systems, including solidification of reject brines – thereby achieving ZLD – were readily available in 2017 and could be fabricated and installed in 12-14 months. It is therefore puzzling to me that EPA has concluded that membrane technologies will not be available for many years into the future.

(ii) New Logic[75] is another technology provider of membrane-based wastewater treatment. Its VSEP system is a new generation membrane filtration system designed for wastewaters containing high total suspended solids (TSS) and total dissolved solids (TDS) and uses vibratory movement to reduce fouling on the membrane surface. The shear created by the rapid change in direction makes it difficult for foulants to attach to the membranes. However, clean water may still pass through the membrane pores.[76] New Logic produces VSEP with RO membranes, suitable for FGD wastewater treatment. The concentrate from the VSEP can be disposed of using a variety of onsite and offsite techniques, including thermal treatment, solidification, achieving ZLD. Various configurations of membranes can be used to achieve treatment. Like other membrane treatment technologies, pretreatment of the raw feed water prior to the VSEP/RO technology is necessary for FGD wastewater treatment applications. Specifically, the raw feed water should be strained to remove grit and large particles, and treated such that the influent TDS does not exceed 100,000 ppm. Another pretreatment step that needs to be considered is chemical addition to remove free chlorine and other oxidants. Dechlorination of the feed may be necessary because chlorine damages the polyamide membranes used in the VSEP system, which would result in a lower membrane rejection rate. Also, like other membrane systems, the VSEP membranes require periodic flushing and chemical cleanings.[77]

EPA reports 6 VSEP pilot studies involving FGD wastewater. With the exception of one pilot study where the wastewater was pretreated by softening with lime and soda ash, New Logic confirmed to EPA that there was no pretreatment prior to the VSEP system. New Logic also confirmed that all studies included spiral RO polishing in the treatment train. EPA states that:

[I]ndustry sources report that the VSEP tests…demonstrate that anti-fouling technology can enable the use of membrane filtration to treat FGD wastewater and that the VSEP/RO treatment train is effective at removing selenium, arsenic, mercury, and nitrate- nitrite to concentrations well below the ELG limitations. These sources also report that the onsite tests demonstrate that the anti-fouling properties of the VSEP system enable it to treat FGD wastewater without the need for extensive pretreatment. Additionally, the VSEP/RO treatment process has a relatively small footprint and obviates the need for the reaction tanks and much of the other equipment typically included as part of chemical-biological treatment trains. Treating FGD wastewater with the VSEP/RO system can achieve significant volume reduction upstream of thermal or solidification zero discharge technologies, thereby reducing the size and cost of the thermal/solidification equipment.[78]

In addition to the pilot studies discussed above, New Logic also reported to EPA in June 2019 that it had installed one full-scale system,[79] which EPA does not discuss in its summary of technologies. This full-scale system installation further establishes that membrane technologies are available today and should serve as the technology basis for FGD effluent limitations.

(iii) EPA also reports discussions with Oasys, [80] whose Forward Osmosis (FO) technology has been installed at two full-scale systems for the treatment of FGD wastewater internationally. At the time of EPA's discussions with Oasys, it had also conducted one pilot study in the U.S. The full scale installations were at the Changxing Power Station with two 660 MW units (the world's first FO-based ZLD, treating 160,000 GPD) and the Shanxi Lujin Wangqu Power Station (treating 79,000 GPD). The Changxing installation was in 2015. The treatment train included solids contact clarifier, filter press, multi-media filtration, and weak acid cation (WAC) ion exchange polishing as pretreatment, then into the Oasys ClearFlo Membrane Brine Concentrator (MBC) system (RO pre-concentration and the FO trains). The concentrated brine was then sent to a crystallizer. Product water was used as boiler makeup water. The Shanxi Lujin system was installed in mid-2017 and included pretreatment prior to entering the MBC system consisting of softening, multimedia filtration, and weak acid cation exchange. The final brine is combined with bottom ash and fly ash for landfill disposal but is not completely encapsulated.[81]

In addition to the two full-scale units above, Oasys also conducted a pilot study at the Southern Company's Water Research Center at Plant Bowen in 2016. For this pilot, the FO units operated as a single-pass operation and did not require cleaning throughout the duration of the study, which totaled more than 300 hours of continuous operation. Untreated FGD wastewater TDS concentrations ranged from 12,000 to 20,000 ppm and 90-95 percent of the raw water was recovered for potential reuse or discharge with a TDS concentration of less than 250 ppm. Brine concentrate had TDS concentrations of up to 300,000 ppm.[82]

Upon exiting the Oasys FO unit, the brine concentrate has a TDS concentration of 250,000 ppm or higher. Brine concentrate may then be fed into a crystallizer, a spray dryer, or mixed with fly ash and lime to manufacture a solid for disposal.[83]

The Oasys systems are designed as modular units that allow each system as an array, with multiple, parallel, trains to treat the capacity of wastewater required.

(iv) Finally, EPA reported some discussions with another vendor called Saltworks Technology (STI).[84] STI reported on pilot-scale and bench-scale testing of its system for successfully treating FGD wastewater. The pilot-scale demonstration in China, in 2017, operated for 90 days and treated 50 gallons of wastewater per day. The system included pretreatment to remove silica, transitional metals and ultra/microfiltration. The incoming FGD wastewater had a total dissolved solids concentration of 19,300 mg/l and the system achieved a RO recovery rate of approximately 91-92%; brine (combined flow of both streams) volume was around 8-9%. [85]

STI also conducted a second pilot study in collaboration with the United States Department of Energy, the Electric Power Research Institute, and Southern Company, treating FGD wastewater to selectively remove chlorides so the wastewater can be reused within the scrubber system.

As EPA notes, STI markets their SaltMaker technology as an alternative to traditional crystallizers or vapor compression systems. The SaltMaker technology uses humidification and dehumidification systems to evaporate the water. The technology can produce more concentrated brine streams or achieve true zero liquid discharge (ZLD) and generate solids.[86]

64 See TDD, Section 4.1.3 for a summary discussion on the various types of membrane technologies and an overview of how they work.
65 TDD at 4-5.
66 EPA briefly discusses such solidification options in the TDD, Section 4.1.5. Actual results from successful solidification (i.e., suitable for disposal in non-hazardous landfills) of reject brines using agents such as fly ash and gypsum (and others) are provided in the record. See KleeNwater, Concentrate Solidification Report (Mar. 27, 2019) (EPA-HQ-OW-2009-0819-7626). This report provides information on brine concentrate management using: fly ash wetting; gypsum wetting; hydrated lime encapsulation; and super absorbent polymer solidification. The study concluded that "[t]he KLeeNwater platform produces concentrates that can be solidified using various methods that achieve compliance with TCLP testing. The most effective solidification methods are fly ash wetting (method 3) and gypsum wetting; these methods resulted in the greatest consumption of concentrate while producing lower leached metals than compared to the other tested methods." Id. at 7.
67 TDD at 6-15 n.47. ("Where the annualized cost for membrane filtration is less than the other regulatory options, the EPA assumed the plant will install membrane treatment and estimated zero post-compliance loadings") (emphasis added). See also ERG Memorandum Re: Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090 (Sept. 25, 2019) (EPA-HQ-OW-2009-0819-8220). (showing pollution loads of zero for all FGD waste streams treated with membrane filtration).
68 See ERG Memorandum Re: Technologies for the Treatment of Flue Gas Desulfurization Wastewater – DCN SE07367 (Oct. 22, 2019) (EPA-HQ-OW-2009-0819-8155).
69 One of the vendors, Oasys, does not appear to be active in the marketplace today. However, its Forward Osmosis technology has likely been sold to others, so the technology itself is not defunct.
70 See Appendix I – KLeenWater Technology (EPA-HQ-OW-2009-0819-8155).
71 As KLeeNwater stated, "[t]he proprietary process has been tested and shown to be effective at reducing contaminants to levels within ELG regulations. Two plants with unique requirements and specifications have found the process to be effective and adaptable. Discharge was able to consistently meet ELG regulations even when feed water was concentrated to provide a worst case scenario. Both systems showed significant removal of bromides, chlorides and boron and can be manufactured to easily handle load cycling (easy shut off and re-start on demand). Permeate water was suitable for reuse or discharge within the State and Federal limits. The proprietary systems all ran consistently and predictably. In addition, the process was shown to be capable of replacing a boron specific ion exchange system, boron regenerate batch treatment system, primary biological system, and secondary biological system." KLeeNwater, Advanced Micro Filtration and Reverse Osmosis for ELG Compliance and ZLD, at IWC-17-03 (2017) (EPA-HQ-OW-2009-0819-7627).
72 Id. See also Katie Mcintyre, EES, Meeting Zero Liquid Discharge Through Reuse and Concentrate Management (EPA-HQ-OW-2009-0819-7647); ERG Memorandum Re: Notes from Meeting with KLeeNwater™ (Aug. 22, 2019) (EPA-HQ-OW-2009-0819-7617).
73 KleeNwater concluded that "Solidification is a viable and cost effective option for ZLD with the process. The tests performed during this trial demonstrated that several types of solidification byproducts could be generated, from slurries to solids using fly ash, lime and RO concentrate. Concentrate may also be managed by evaporation, brine crystallization or hauled off site, depending on the site and what option would be most economical." KleeNwater at IWC-17-03 (EPA-HQ-OW-2009-0819-7627).
74 See the following: DCN SE07065A16, May 2017 proposal for redacted client, through Black and Veatch. DCN SE07065A17, May 2017 proposal for redacted client, through Black and Veatch. DCN SE07065A18, November 2017 proposal for redacted client through Burns and McDonnell.
75 See Appendix K – New Logic Membrane Technology (EPA-HQ-OW-2009-0819-8155).
76 See id. at K-2.
77 Id. at K-4.
78 Id.at K-5.
79 Email Correspondence of Greg Johnson, New Logic Research, Inc. and Phillip Flanders, EPA, Re: Implementation Timelines for Membranes (June 2019) (EPA-HQ-OW-2009-0819-8179):
Regarding our system that was installed at the research center in Atlanta, I can confirm that it is b egin moved to the new location and that it will be a permanent installation to treat about 50 gpm of FGD effluent. This is the total flow that they have and this is not intended to be a pilot, it is a final treatment plant that will be permanent.

80 See Appendix L – Oasys Forward Osmosis Technology (EPA-HQ-OW-2009-0819-8155). See also ERG Memorandum Re: Notes from Meeting with Oasys Water™ (Feb. 16, 2018) (EPA-HQ-OW-2009-0819-7334).
81 See Appendix L – Oasys Forward Osmosis Technology, at L-3 – L-4.
82 Id. at L-4.
83 Id.
84 See Appendix N – Saltworks Technology (EPA-HQ-OW-2009-0819-8155). See also ERG Memorandum Re: Notes from Conference Call with Saltworks Technologies Inc. (May 8, 2019) (EPA-HQ-OW-2009-0819-7332). 85 See Appendix N – Saltworks Technology, at N-3.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 75

Comment Excerpt:

VI. BROMIDES

In this rulemaking, EPA proposes not to set membrane filtration technology—or any technology, for that matter—as BAT for bromide reduction. Instead, it proposes to impose no limits for bromide and instead rely entirely on plants' participation in the *Voluntary* Incentive Program to achieve the health benefits it credits to Option 2. EPA's approach is unacceptable for many reasons, not the least of which is that membrane filtration is available and economically achievable and therefore should be used as BAT, as explained above. It is also unacceptable because EPA's assumption that plants will voluntarily implement membrane filtration under VIP is completely speculative.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 78

Comment Excerpt:

As EPA admits,[267] membrane filtration, or equivalent zero-discharge technology, is the only technology that would adequately control bromide, and therefore, it should be used as BAT.

[267] See, e.g., Proposed TDD at 8-2 and 8-4 (stating that bromide is "not reliably removed" by chemical precipitation or "CP+LRTR"), and id. at 8-6 ("Based on data for thermal systems and process knowledge and performance data for membrane systems, all pollutants present in FGD wastewater would be effectively treated by membrane filtration").

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 90

Comment Excerpt:

Instead of placing the burden on downstream communities, EPA must establish an effluent limitation for bromide based on membrane filtration, which would filter out bromides and avoid public health effects downstream. Utilities are in the best position to shoulder the cost of bromides; not downstream communities.

EPA must fix these environmental injustices by following the mandate of the Clean Water Act and establishing increasingly stringent effluent limitations for power plants based on truly "best" available technology, without any carve-outs, as we explain above.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 42

Comment Excerpt:

B. Only Membrane Technology or Other Zero-Discharge Technologies Address Pollution from Bromides

Most of the environmental benefit that EPA assumes for the Proposed Rule comes from reduced bromide loads, with an associated decrease in bladder cancer incidence and mortality.[159] Of the technologies evaluated by EPA, only membrane filtration and thermal evaporation technologies can reduce bromide loads.[160] EPA has a legal obligation to require technology that will "result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants," and, if the technology is available, to eliminate the discharge.[161] For bromide – which dominates EPA's estimated environmental benefit – the only technologies that meet EPA's statutory mandate happen to be zero-discharge technologies (membrane filtration or thermal treatment).

[159] See, e.g., 84 Fed. Reg. at 64,660, tbl. XII-8. EPA predicts a mix of environmental benefits (e.g., "reduced cancer risk from DBPs in drinking water" associated with bromide reductions) and 'negative' or foregone environmental benefits (e.g., the cost of increased CO2 emissions). Of environmental benefits with a positive value, the reduced cancer risk from DBPs in drinking water – valued at $37.6 million for the mid-range Option 2 scenario – is by far the largest category. Without these assumed benefits, Option 2 would have a net environmental cost.
[160] See, e.g., Proposed TDD at 8-2 and 8-4 (stating that bromide is "not reliably removed" by chemical precipitation or "CP+LRTR"), and id. at 8-6 ("Based on data for thermal systems and process knowledge and performance data for membrane systems, all pollutants present in FGD wastewater would be effectively treated by membrane filtration").
[161] 33 U.S.C. § 1311(b)(2)(A).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 71

Comment Excerpt:

B. The Record Shows FGD Wastewater Limits Must Be Strengthened to Address Bromide Discharges.

As discussed in Section VI - Zero Discharge FGD of these comments, the EPA record demonstrates that membrane technology or its equivalent is BAT for FGD wastewater discharges. Only membranes or equivalent technology would adequately control bromide discharges, and the agency has a legal obligation to require technology to eliminate this pollution. According to EPA, requiring membranes for FGD at all plants would remove twenty-nine million pounds of bromide annually[261] and avoid 769 bladder cancer cases.[262] By contrast, if the eighteen plants that EPA predicts will participate in the Voluntary Incentives Program install membranes, only 343 bladder cancer cases would be avoided [263] and thirteen million pounds of bromide would be removed annually – and not until 2028.[264]

[261] ERG, Bromide Loadings for FGD Wastewater (MS Excel spreadsheet) – DCN SE07260A1, Docket ID No. EPA-HQ-OW-2009-0819-8242 (2019).
[262] Proposed BCA at 4-18, Tbl. 4-7.
[263] Id.
[264] ERG, Bromide Loadings for FGD Wastewater (MS Excel spreadsheet) – DCN SE07260A1, Docket ID No. EPA-HQ-OW-2009-0819-8242 (2019).

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 4

Comment Excerpt:

EPRI's annualized cost estimate for membrane-based treatment with encapsulation is more than 10 times EPA's estimate.

- EPA appears to have underestimated the cost of VIP treatment. EPA's membrane filtration cost curves do not include all of the pretreatment and disposal costs necessary for a complete membrane filtration treatment system.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 5

Comment Excerpt:

Costs for membrane treatment at some plants will be much higher and potentially not economically viable.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 6

Comment Excerpt:

EPA appears to have underestimated FGD wastewater VIP cost relative to the cost of FGD wastewater BAT (chemical precipitation plus biological).

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 27

Comment Excerpt:

4.1 **EPA appears to have underestimated the cost of VIP treatment. EPA's membrane filtration cost curves do not include a complete membrane filtration system with all the required unit operations necessary. EPRI's annualized cost estimate for membrane-based treatment with encapsulation is more than 10 times EPA's estimate.**

EPA's cost estimates are generally lower than would be expected taking into account pretreatment and membrane costs. EPRI compared (Table 4-1) EPA's cost estimates for a 300 gpm pretreatment and membrane system that uses onsite disposal, published as cost curve equations shown in the *Flue Gas Desulfurization Membrane Filtration Cost Methodology* memorandum (ERG, 2019b), with our estimates of the cost to comply using two potential membrane system design approaches:

- EPRI Case Study 1: Chemical Softening, Ultrafiltration (UF), Seawater Reverse Osmosis (SWRO) and Brine Solidification (BS) (e.g., encapsulation)

- EPRI Case Study 2: Chemical Precipitation, Advanced Membrane Filtration and Brine Solidification

Table 4-1
FGD VIP cost comparison for a case study plant designed for 300 gpm membrane system

Cost Element	EPA Pretreatment and Membrane [1]	EPRI Case Study 1: Chemical Softening, SWRO and Brine Solidification [2]	EPRI Case Study 2: Chemical Precipitation, Advanced Membrane Filtration and Brine Solidification [2]
Pretreatment	Microfiltration [3]	Chemical Softening/Clarifier	Chemical Precipitation /Clarifier
Membrane	Advanced Membrane Filtration (assumed recovery unknown)	UF + SWRO (81% recovery)	Advanced Membrane Filtration (70% recovery) [4]
Peak Design Flow (gpm) [5]	300	300	300

Table 4-1 (continued)
FGD VIP cost comparison for a case study plant designed for 300 gpm membrane system

Cost Element	EPA Pretreatment and Membrane, Onsite Disposal [2]	EPRI Case Study 1: Chemical Softening, SWRO and Brine Solidification [1]	EPRI Case Study 2: Chemical Precipitation, Advanced Membrane and Brine Solidification [1]
Capital Costs ($M)	***21***	***102***	***127***
Capital Cost Elements:			
Chemical Softening ($M)	--	57	--
Chemical Precipitation ($M)	--	--	35
Membrane Filtration + Brine Solidification ($M)	21	28	63
Brine Amendment Storage ($M)	--	17	29
O&M Flow basis (gpm) [5]	187.5	153	153
O&M Costs ($M/yr)	***2***	***30***	***49***
O&M Cost Elements:			
Chemical Pretreatment ($M/yr)	--	3.3	0.7
Membrane ($M/yr)	< 2	1.7	5.0
Brine Solidification and Disposal ($M/yr)	< 2	25	43
Total Annualized Cost ($M/yr)	**4**	**40**	**61**

Table 4-1 (continued)
FGD VIP cost comparison for a case study plant designed for 300 gpm membrane system

BS = Brine solidification
gpm = gallons per minute
RO = Reverse osmosis
UF = Ultrafiltration membrane
M = million
SWRO = Seawater reverse osmosis
$ = U.S. dollars, pre-tax in 2018 dollars
Assumes 7% interest rate and 20-year life for annualized cost.
[1] Costs were estimated based on EPA's cost curve for a "Pretreatment and Membrane" system with onsite disposal. [ERG, 2019d]
[2] EPRI Appendix D provides summary of case study descriptions, cost methodology and cost estimates.
[3] EPA defines pretreatment as microfiltration on page 5-4 of the *Supplemental Technical Development Document* [EPA, 2019a].
[4] EPRI's advanced membrane filtration system costs are based on the New Logic VSEP system. It is one of the advanced membrane technologies that EPA describes evaluating since the 2015 rule [ERG, 2019a]. EPRI estimated the cost for a 300 gpm VSEP + spiral wound RO polishing system, with 120% redundancy, based on cost information provided to EPA [EPA, 2019b] and previous VSEP cost estimates available to EPRI.
[5] Peak flow was used for sizing equipment and developing capital cost estimates. EPRI case studies assume a capacity factor of 0.51 (see Appendix D for basis). EPA O&M flow basis was calculated based EPA Equation 5-3 and median plant flow optimization factor equal to 0.375 [EPA, 2019a].

The major differences between these case study estimates made by EPA and EPRI include the following, each of which is discussed in more detail in the subsections below:

1. Solids settling and chemical precipitation pretreatment upstream of membrane filtration should be included. EPA is underestimating the costs of the case study plant by approximately $30 million to $60 million in capital cost and up to $3 million per year in O&M cost by not including pretreatment considerations.
2. EPA's Operations and Maintenance (O&M) cost underestimates waste solidification and disposal costs by approximately $20 million to $40 million per year and membrane cleaning and replacement costs by up to $5 million per year.
3. EPA's cost appears to be missing treatment support systems (backwash, solids storage, brine amendment storage, chemical storage, clean-in-place system).

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 31

Comment Excerpt:

4.2 **Costs for membrane treatment at some plants will be much higher and potentially not economically achievable.**

The costs presented in Table 4-1 above represent a typical power plant in terms of FGD wastewater composition and fly ash generation. However, there will be wide variation across the industry. Costs would be higher at plants that do not have sufficient fly ash to solidify the RO brine and therefore would have to buy additional amendments (such as fly ash, quicklime, or portland cement).

More significantly, EPRI's Case Study 1 assumed a maximum achievable 81 percent overall permeate recovery, which was limited by the FGD wastewater's salinity and the allowable SWRO membrane design pressure. Permeate recovery would be lower, and therefore costs would be much higher, for those plants who cannot achieve this high membrane recovery.

Lower recovery leads to a significant increase in the wastewater volume that must be encapsulated and disposed of resulting in higher capital costs for pugmill systems and brine amendment storage and higher O&M costs for brine amendments, lost fly ash sales and landfill disposal. Lower recovery could be due to several potential factors including high chloride and/or TDS in FGD wastewater, membrane scaling and/or fouling issues, pretreatment system upsets, or frequent membrane flushing. A system designed to achieve the low permeate limitations of the ELG VIP option would likely need to sacrifice recovery in order to comply with the limits, also leading to higher costs.

EPRI's evaluation of fly ash availability and RO system recovery and their associated effect on cost is reflected in a sensitivity analysis in Table 4-2. EPRI evaluated case studies achieving 81, 70 and 50 percent overall recovery. For comparison, the advanced membrane technologies that EPA has considered since the 2015 rule [ERG, 2019a] report a significant range in overall membrane recoveries that have been demonstrated. The most complete dataset was provided by New Logic VSEP (Appendix K, Table 1 of ERG document [2019a]), which shows a range of 55 to 83.2 percent overall recovery achieved in six different FGD wastewater pilots. The average overall recovery for these pilots was 72 percent.

Table 4-2
FGD membrane treatment sensitivity to varying fly ash availability and RO recovery—EPRI estimates

Cost Element	Case Study [1]	RO Recovery Analysis		Fly Ash Availability Analysis	
Overall membrane recovery (%)	81%	70%	50%	81%	81%
Fly Ash Available (tons/year) [2]	198,000	198,000	198,000	119,000	336,000
Capital Cost ($M)	102	120	155	111	90
Annualized Capital Cost ($M/year) [3]	9.6	11	15	10	8.5
O&M Costs ($M per year) [4]	30	49	84	36	22
Wastewater Treatment ($M/year) [5]	15	25	43	19	8.6
Disposal ($M/year)	14	23	39	16	12
Lost Fly Ash Sales ($M/year)	1.2	1.2	1.2	0.7	1/7
Total Annualized Costs ($M/year) [6]	**40**	**61**	**98**	**47**	**30**

[1] EPRI Appendix D provides summary of case study 1 description, cost methodology and cost estimates.
[2] EPRI estimated the fly ash available for an average site, and an approximate range of fly ash generated for 300 gpm plants in the industry, based on plant MW, heat rate, heat content in coal, and assumed 0.51 capacity factor.
[3] Annualized cost based on a 20-year equipment life and 7% interest rate.
[4] Total O&M cost including wastewater treatment costs, disposal costs and lost fly ash sales.
[5] Wastewater treatment O&M costs including electricity, chemicals, labor, membrane replacement, equipment maintenance, compliance monitoring, and miscellaneous unidentified cost.
[6] Total annualized cost, including annualized capital cost and total O&M cost. Assumes 7% interest rate and 20-year life for annualized cost.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 59

Comment Excerpt:

3. The Costs of Implementing Membrane and Paste Encapsulation Technologies Will Be Much Higher than EPA's Estimates.

In addition to the knowledge gaps associated with these emerging technologies, they are not economically achievable for the industry as a whole. To assess the potential costs of installing membrane filtration technologies, EPA apparently considered plant-specific costs for pretreatment, membrane filtration, brine management, and disposal of solids. According to ERG's FGD membrane filtration cost methodology, EPA collected data from membrane filtration vendors, who provided capital and O&M costs for FGD wastewater flows ranging from approximately 10,000 GPD to 5,000,000 GPD.[86] ERG then augmented the data it received from each vendor to estimate the full costs.[87] As a result, ERG established cost curves based on FGD purge flow rate. For example, for a facility with pretreatment and an FGD wastewater flow rate of 1,500,000 GPD, EPA estimated that its capital costs would be approximately $75 million and O&M costs would be approximately $10 million/year.[88] However, this analysis does not appear to take into consideration the full costs of pretreatment, the full costs associated with solidifying and disposing of the encapsulated waste, and critical elements of the FGD wastewater treatment system. Moreover, at some plants, costs would be so significant that this technology likely would not be feasible.

[86] ERG, *Memorandum re: Flue Gas Desulfurization Membrane Filtration Cost Methodology – DCN SE07096,* EPA-HQ-OW-2009-0819-7811 (Aug. 23, 2019) ("ERG, EPA-HQ-OW-2009-0819- 7811") at 1.
[87] Id. at 2, 4 (including: (i) purchased equipment costs (e.g., membrane filtration skids, pretreatment system, pumps, tanks, etc.), (ii) direct capital costs (e.g., installation, site preparation, instrumentation and controls, etc.), (iii) indirect capital costs (e.g., engineering and supervision, contractor's fees, etc.), and (iv) O&M costs (e.g., operating labor, maintenance materials, energy, sludge transportation and disposal, etc.).
[88] Id. at 3, 5.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 26

Comment Excerpt:

3. EPA has significantly underestimated the cost of membrane systems.

EPA has failed to account for all the costs associated with this treatment technology in assessing the feasibility of it. EPRI recently analyzed the true costs of these systems, among other things.[43]

EPRI determined that anticipated annualized costs for a membrane treatment system for FGD wastewater were more than ten times EPA's estimate.[44] A key difference in the estimates stems from EPA's failure to consider costs for pretreatment.[45] In fact, EPA's cost for membrane treatment does not appear to include cost considerations (including equipment, chemicals, and solids byproduct management) for any chemical precipitation pretreatment or upstream settling of solids that would be required to avoid fouling/scaling of the membrane treatment system.

EPA must consider the full spectrum of costs, including a complete membrane system, required support systems, O&M, and waste products management in the agency's statutorily mandated BAT evaluations. For membrane technologies, significant cost factors that require additional evaluation include feed water equalization, chemical softening, solids removal, biofouling mitigation and free-chlorine removal, oxidant reduction, pH adjustment and antiscalant, membrane chemical cleaning, membrane treatment systems, and balance-of-plant systems and equipment. This technology cannot be labeled BAT until the complete costs of it are fully comprehended.

43 ELEC. POWER RES. INST., CONSIDERATIONS FOR TREATING FLUE GAS DESULFURIZATION WASTEWATER USING MEMBRANE AND PASTE ENCAPSULATION TECHNOLOGIES 3-4 (2019).
44 Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 4-1 to 4-2.
45 Id. at 4-3 to 4-4.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 28

Comment Excerpt:

4.1.1 **Solids settling and chemical precipitation pretreatment upstream of membrane should be included. EPA is underestimating the costs of the case study plant by approximately $30 to $60 million in capital cost and up to $3 million per year in O&M cost.**

EPA's basis for membrane "pretreatment" costs warrants further clarification and evaluation. In developing a "pretreatment and membrane" cost curve, EPA appears to be assuming that the pretreatment costs include only a "Pretreatment system (microfiltration skid)" as noted on page 5-4 of the *Technical Development Document* [EPA, 2019a].

Therefore, it appears that the EPA cost for membrane treatment does not include any chemical precipitation pretreatment or upstream settling of solids that would be required to avoid overloading the membrane treatment system that EPA defines as microfiltration and reverse osmosis. Solids removal (using either gravity settling in ponds or tank-based pretreatment) is included in all of the pilot systems, where pretreatment is clearly described [ERG, 2019a]. Several examples include:

- FMX example process flow diagram assumes chemical pretreatment and clarification pretreatment (Appendix B, Figure B-1 of ERG document [2019a]).
- The KLeeNwater "pilot treatment system included physical/chemical treatment, I-MICRO, IPRO and B-PRO" (page I-3 of ERC document [2019a]).
- "Pretreatment of the raw feed water prior to the VSEP/RO technology is necessary for FGD wastewater treatment applications" (page K-4 of ERG document [2019a]).
- "The (Changxing Power station) treatment train consists of a solids contact clarifier, filter press, multi-media filtration, and weak acid cation (WAC) ion exchange polishing as pretreatment, then into the ClearFlo MBC system (RO pre-concentration and the FO trains)" (page L-3 of ERG document [2019a]).
- Satisfactory membrane pretreatment will provide protection of the membrane elements, help attain/maintain reliable performance and improve membrane system recovery. As noted, "Including pretreatment prior to the FMX system may increase overall process efficiency of the FMX system and help lower the capital and operations and maintenance costs of the FMX portion of the system" (page B-2 of ERG document [2019c]).

Pretreatment would also be required to avoid unacceptable scaling. It would be required to remove suspended solids and at least some scaling ions—such as calcium and magnesium. Based on industry practice, EPRI has assumed Case Study 1 (spiral-wound SWRO) would include lime and soda ash chemical softening upstream for removal of calcium and magnesium that would otherwise cause significant scaling issues on the surface of the membranes. For advanced membrane filtration (Case Study 2), EPRI has assumed chemical precipitation is required including partial removal (desaturation) of calcium by addition of lime. These processes are illustrated in Figure 4-1.

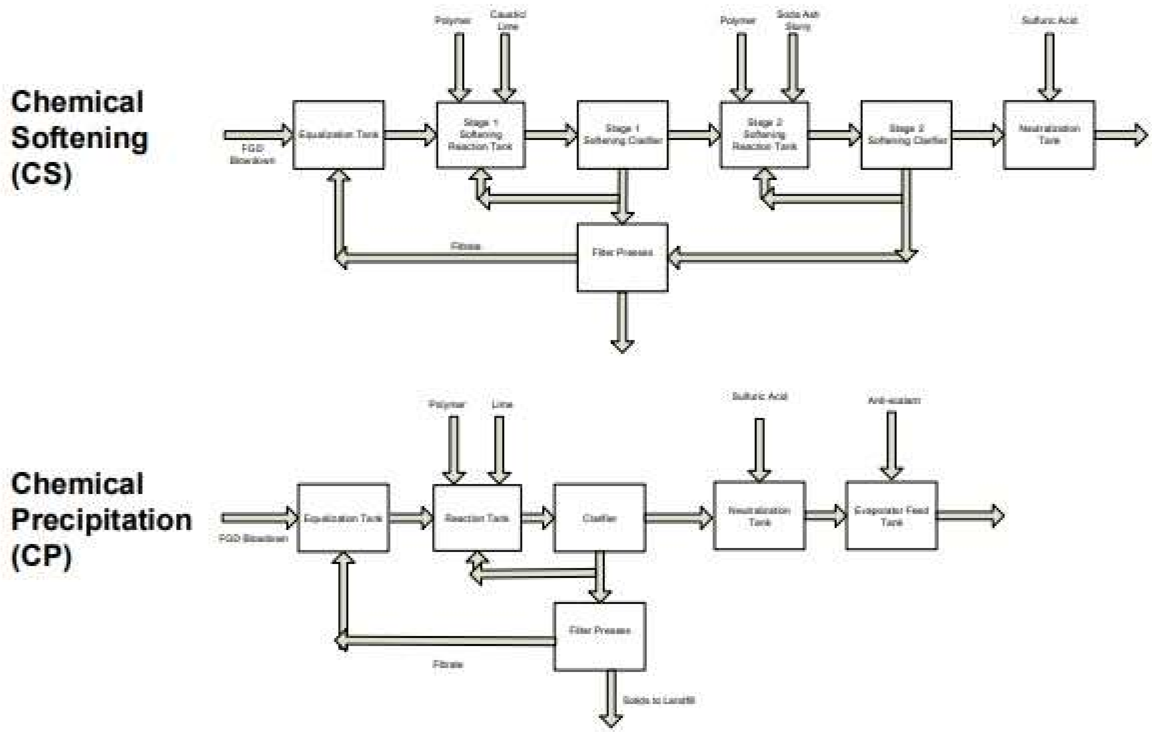

Figure 4-1
Pretreatment needed for successful membrane treatment of FGD wastewater

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 33

Comment Excerpt:

4.4 **EPA underestimated FGD wastewater VIP costs relative to cost of FGD wastewater BAT.**

The EPA cost estimates for the VIP option are lower than EPA's estimate of BAT (chemical precipitation plus biological) for some plants. EPA's cost curves from the 2019 ELG Technology Development Document Section 5 [EPA, 2019a] are overlain in Figures 4-2 and 4-3. EPRI estimates that the VIP option costs are significantly more than the BAT option, as shown in Table 4-4. A key difference between EPRI and EPA costs appear to be that EPA is not fully accounting for the chemical pretreatment that is required before membranes (as discussed in Comment 4.1.1). To illustrate this, EPRI is showing a new plot combining EPA's cost curves for chemical precipitation pretreatment (Figures 5-7 and 5-8 of EPA document [2019a]) and pretreatment (MF) and membrane (Figures 5-19 and 5-20 of EPA document [2019a]). Even though EPRI believes there are technical deficiencies in the calculation of each of those curves, at a minimum the curves for chemical precipitation and membrane treatment should be combined to incorporate a more realistic cost estimate for the VIP option. Once chemical pretreatment is fully accounted for in the costs, the costs of chemical precipitation with high nitrate LRTR biological treatment (BAT) are lower than the costs of chemical precipitation with membrane treatment in nearly all cases.

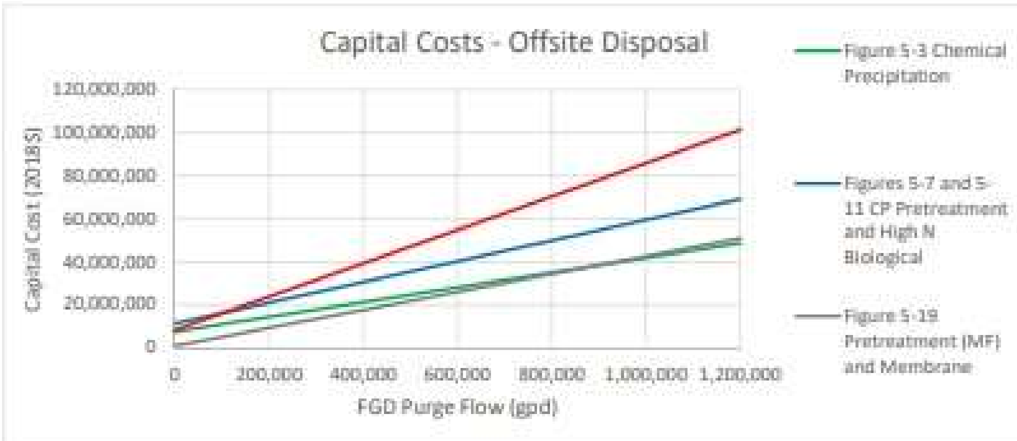

Figure 4-2
Comparison of EPA's capital cost curves (EPA, 2019a]

Figure 4-3
Comparison of EPA's O&M cost curves [EPA, 2019a]

Table 4-4
EPRI's and EPA's cost estimates of FGD BAT versus FGD VIP at a case study plant designed for 300 gpm

Cost Element	EPA BAT	EPRI BAT	EPA VIP	EPRI VIP	
Treatment System	Chemical Precipitation) + Biological [a]	Chemical Precipitation + Biological [b]	Pretreatment + Membrane [c]	Case Study 1: Chemical Softening, SWRO + Brine Solidification [d]	Case Study 2: Chemical Precipitation, Advanced Membrane Filtration + Brine Solidification [e]
Peak Design Flow (gpm) [f]	300	300	300	300	300
Capital Costs ($M)	32	47	19	102	127
O&M Flow Basis (gpm) [f]	187.5	153	187.5	153	153
O&M Costs ($M/yr)	2.3	2.0	3.8	30	49
Total Annualized ($M/yr)	5.4	6.5	5.6	40	61

BAT = Best Available Technology Economically Achievable
M = million
$M/yr = million dollars per year
$ = U.S. dollars, pre-tax in 2018 dollars
VIP = Voluntary Incentives Program
[a] Sum of costs using EPA's cost curves for chemical precipitation pretreatment and LRTR – high nitrates with offsite disposal [EPA, 2019a]
[b] EPRI estimated costs for a 2 x 60% chemical precipitation plus high-N LRTR biological system. EPRI has assumed a 0.51 online factor for the chemical precipitation system and 0.75 online factor for the biological system (Appendix B).
[c] Costs were estimated based on EPA's cost curve for a "Pretreatment and Membrane" system with offsite disposal. [ERG, 2019a]
[d] EPRI Case Study 1: 2 x 60% chemical softening, N + 1 UF, N+1 SWRO membrane and 2 x 100% pugmill systems (Appendix D)
[e] EPRI Case Study 2: 2 x 60% chemical precipitation, 120% VSEP + spiral wound RO polishing system and 2 x 100% pugmill systems (Appendix D).
[f] Peak flow was used for sizing equipment and developing capital cost estimates. EPRI case studies assume a capacity factor of 0.51 for estimating O&M costs (see Appendix D for basis). EPA O&M flow basis was calculated based EPA Equation 5-3 and median plant flow optimization factor equal to 0.375 [EPA, 2019a].
Technology abbreviations are consistent with other tables in this section.
Assumes 7% interest rate and 20-year life for annualized cost.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 35

Comment Excerpt:

5.1.1 **Pretreatment is critical for attaining/maintaining reliable operation of membrane-based systems and can represent a significant, majority portion of the total cost of a system.**

Pretreatment is critical for attaining/maintaining reliable operation of membrane-based filtration treatment systems. The type and extent of pretreatment will depend on the membrane process chosen, source water characteristics, and the treatment objectives (including the waste management plan). Pretreatment can represent a significant and majority portion of the total cost of a system.

The rejection of dissolved solids by membrane technologies is also impacted by the water composition in the feed stream and so inherently impacted by the performance of the pretreatment system and the site-specific source water characteristics. Removing the majority of foulants prior to reverse osmosis membranes (with pretreatment) will allow the system to operate at a higher flux and produce a higher percentage of permeate compared to lower flux values. Suboptimal pretreatment can lead to fouling, scaling, and general loss of performance, requiring frequent chemical cleaning and/or membrane replacement.

Membrane treatment technology selection and operations are highly dependent on source water characteristics, and membrane systems have limitations. Various conditions and characteristics affect membrane reliability, such as:

- **Concentrations of suspended solids/particles and dissolved solids.**
- **Scaling potential of the constituents,** which occurs when the concentration of the constituent is above the saturation limit at the membrane surface. Scale formation blocks water from passing through the membrane, which may lead to lower recovery, reduced salt rejection and reduced membrane life.
- **Presence of foulants,** which can lead to plugged areas on the membrane that might not be removed by flushing or chemical cleaning. Common foulants include suspended solids, metal precipitates, polymers used in upstream systems, and organic matter.
- **Presence of biofoulants,** which may be mitigated with pre-filtration and disinfection, however the free chlorine can also cause rapid deterioration of the membrane.
- **Presence of oxidizers,** whereby the highly oxidized nature of FGD wastewater could significantly reduce membrane life compared to other industrial applications.
- **Chemical properties (pH and oxidation-reduction potential),** which could lead to chemical attack of the membranes
- **Temperature,** which could impact membrane flux and performance

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 37

Comment Excerpt:

5.2 **EPA should use the same technology basis to develop membrane treatment costs and numerical effluent limitations.**

EPA’s costs for membrane filtration appear to include either: (1) pretreatment (MF) and membrane filtration or (2) membrane filtration alone where a plant’s treatment in place is more advanced than surface impoundments [EPA, 2019b; EPA, 2019d]. As noted in Comment 4.1, EPA appears to be underestimating the need and cost for tank-based chemical precipitation treatment and solids settling. However, in setting limits, EPA is establishing membrane permeate limits based on pilot sample datasets where optimized tank-based chemical precipitation systems were used for pretreatment upstream of the membrane system. The appropriate approach is to use the same technology basis to develop both membrane treatment costs and effluent limitations.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 60

Comment Excerpt:

a. EPA Omits Necessary Pretreatment Costs.

As noted above, pretreatment provides protection for elements of the membrane system, maintains its reliable operation, and improves system recovery by removing suspended solids, such as calcium and magnesium. Suboptimal pretreatment can lead to fouling or scaling and an overall loss of performance, requiring frequent chemical cleaning or replacement. In developing its cost curves, EPA appears to assume that only a "microfiltration skid" would be used during the pretreatment process.[89] To avoid overloading the membrane treatment system, however, chemical precipitation or chemical softening would be required as pretreatment and should be included in the cost estimates. EPRI estimates that, for a 432,000 GPD treatment system, the capital costs of pretreatment would range from approximately $35 million for chemical precipitation, to approximately $57 million for chemical softening, and up to $3 million per year in O&M costs for the pretreatment system alone.[90] Indeed, because EPA does not fully account for pretreatment, EPA's cost estimates for the voluntary incentive program ("VIP") option are lower than EPA's estimate of BAT (chemical precipitation plus biological) for some plants.[91]

[89] See Supplemental TDD at 5-4.
[90] EPRI 2020 Comments at Table 4-1.
[91] Id. at 4-9 – 4-10.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 29

Comment Excerpt:

4.1.2 **EPA appears to have underestimated the O&M cost of solidification/disposal (by approximately $20 million to $40 million per year) and membrane cleaning & replacement cost (by up to $5 million per year). EPRI's estimated annual O&M cost is more than 15 times the annual O&M cost estimated by EPA.**

EPA's estimated O&M cost of a 300-gpm system consisting of microfiltration (MF) pretreatment, membrane filtration and encapsulation with onsite landfill disposal is approximately $2.3 million per year and with offsite disposal is approximately $3.8 million per year [ERG, 2019b]. EPA's basis for calculating the capital and O&M cost differences for onsite and offsite disposal methods need to be further documented and clarified. Further, EPA has provided only a single cost curve for total capital and total O&M costs, which limits EPRI's ability to compare EPA's costs with its own cost estimates.

EPRI estimated the O&M costs for two 300-gpm membrane treatment systems and then compared the costs to EPA's estimated O&M cost. As seen in Table 4-1, EPRI's estimated costs for brine solidification and waste disposal are $25 million to $43 million per year for a single 300 gpm FGD wastewater plant, which is 10 to 20 times EPA's estimate of the total annual O&M cost for the same plant. Based on EPRI's analysis, EPA is significantly underestimating the cost to solidify and dispose of the encapsulated waste. EPRI assumed a residuals disposal unit cost of $54 per ton on a dry-weight basis, which is based on EPA's assumed unit costs for onsite and offsite disposal [EPA, 2013] and escalated the cost in 2013 dollars to June 2018 dollars (costs escalated to account for the change in price over time). EPRI developed a blended unit cost assuming that 25 percent of plants would use offsite landfills and 75 percent use onsite landfills.

Further, it appears that EPA is underestimating the O&M costs for the membrane system. EPRI's O&M cost estimate for the membrane filtration treatment subsystem alone is up to $5 million higher than EPA's total estimated annual O&M cost. EPA's basis for estimating these costs is confidential business information (CBI). However, EPA's costs appear to be underestimated knowing that the total O&M must also include several other significant cost items, including brine solidification, waste disposal, lost fly ash sales, and other costs.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 61

Comment Excerpt:

b. EPA Underestimates O&M Costs.

To dispose of the resulting waste stream (i.e., the brine), most facilities would employ a solidification process that would generate a non-pumpable solid waste stream that would be trucked and disposed of in a landfill. To accomplish this, many sites would need to forfeit sale of some or all of their fly ash for use in the brine solidification process. While paste encapulation technology may help improve disposal costs, as described above, this is not a mature technology. Thus, EPA must take into consideration the costs to solidify and dispose of the encapsulated brine. EPA's estimated O&M costs, however, do not appear to account for the disposal process. For a 432,000 GPD treatment system consisting of membrane filtration and encapsulation and onsite landfill disposal, EPA estimates approximately $3 million per year in total O&M costs. For offsite disposal, EPA estimates approximately $5 million per year.[92] These figures are substantially smaller than EPRI's estimated costs for brine solidification and waste disposal at $25-43 million per year.[93]

Furthermore, within the cost methodology memorandum, ERG claims to take into consideration the plant's method of transportation and disposal of the waste (onsite or offsite) but does not appear to calculate or consider the full costs associated with waste management. Based on the cost curves that appear in the memorandum and EPA's Supplemental TDD,[94] it somehow costs less to dispose waste offsite, when compared to onsite disposal (e.g., 1 million GPD = ~$50 million onsite, and 1 million GPD =~$40 million offsite). ERG and EPA do not explain why it costs more to dispose waste onsite.

Even if paste encapsulation could be deployed to transport and dispose of the brine, the scientific research indicates a facility's capital expenses and operating costs could be substantial, depending on site-specific factors. For example, the distance between the plant and landfill will determine what type of equipment and configurations may be needed. As viscosities and pumping distances increase, larger pumps with higher discharge pressures as well as the amount and strength of pipe required increase, which "will likely have the largest impact" on capital costs.[95] In terms of operating expenditures, the concentration of the wastewater will dictate the type and amount of chemical additives required, "the largest operating expenditure for paste systems." [96]

[92] ERG, EPA-HQ-OW-2009-0819-7811 at 5-6.
[93] EPRI 2020 Comments at Table 4-1.
[94] Supplemental TDD at 5-26 – 5-27.
[95] EPRI Membrane Report at 13.
[96] Id. at 14.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 30

Comment Excerpt:

4.1.3 **EPA cost appears to be missing support systems (backwash, solids storage, brine amendment storage, chemical storage, clean-in-place system).**

EPA's capital cost elements include the purchased equipment costs for "membrane filtration skids, tanks, pumps, pretreatment system (for reverse osmosis at applicable plants), and brine mixing skid for concentrate management." [ERG, 2019a]. Given this limited description, it appears that EPA's capital costs are missing several critical components of the total wastewater treatment system including:

- Backwash tanks and pumps to support the microfiltration system
- Storage for dewatered solids and backwash solids
- Storage and conveyance system for brine amendment materials (e.g., fly ash, quicklime, portland cement)
- Storage and pumps for membrane chemicals (e.g., antiscalant, acid, caustic)
- Clean-in-place (CIP) system to support cleaning of membrane filtration skids including chemical feed pumps and tanks for temporary storage of CIP waste and neutralization

As shown in Table 4-1, EPRI's capital cost estimate is higher than EPA's estimate for the membrane-only subsystem. One of the reasons EPRI's capital cost estimates are higher may be due to EPRI's inclusion of these required support systems.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 62

Comment Excerpt:

c. EPA Overlooked Important Components of a Membrane Treatment System in Its Capital Cost Estimate.

ERG considered the following capital cost elements in its membrane filtration cost methodology memorandum: purchased equipment, direct, and indirect costs.[97] The purchased equipment costs include membrane filtration skids, tanks, pumps, a pretreatment system (for reverse osmosis at applicable plants), and a brine mixing skid for concentrate management.[98] According to EPRI, this list appears to be missing several critical elements of a membrane filtration treatment system for FGD wastewater, including:

- backwash tanks and pumps to support the microfiltration system;
- storage for dewatered solids and backwash solids;
- storage and conveyance system for brine amendment materials (e.g., fly ash, quicklime, Portland cement);
- storage and pumps for membrane chemicals (e.g., antiscalant, acid, caustic); and
- clean-in-place ("CIP") system to support cleaning of membrane filtration skids including chemical feed pumps and tanks for temporary storage of CIP waste and neutralization.[99]

[97] ERG, EPA-HQ-OW-2009-0819-7811 at 2.
[98] Id.
[99] EPRI 2020 Comments at 4-6.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 47

Comment Excerpt:

6.2 **FGD VIP pollutant removals**

EPRI's estimate of pollution reduction for the FGD VIP option are roughly comparable to the EPA's, as shown in Table 6-2.

Table 6-2
Pollution reduction estimates by EPRI and EPA

Treatment	EPRI # of Plants	EPA Mass (lb/yr)	EPRI Mass [1]	EPRI Mass per plant (lb/yr per plant)	EPA TWPE/yr	EPRI TWPE/yr [1]	EPRI TWPE/yr per plant
Incremental VIP [2] Benefit vs CP alone	38	1,340,000,00 [3]	912,000,000	24,000,000	486,000 [4]	391,000	10,300

[1] EPRI mass and TWPE estimates based on calculations described in Appendix G
[2] EPA's incremental biological was calculated by subtracting Option 1 by Option 4. The difference in technology demonstrates incremental VIP with the exception of high FGD flow facilities as listed in Option 4. EPRI estimates that only 1 facility falls under that technology and that this facility only contributes to 14% of the total industry flow. Therefore Option 1 minus Option 4 can represent incremental biological.
[3] EPA's value is based on Option 1 minus Option 4 in Table 6-3 in EPA's Technical Development Document
[4] EPRI calculated EPA's VIP benefit by subtracting the different options. Specifically, this is the sum of the Baseline + Change in Loadings from Option 1 minus the sum of the Baseline + Change in Loadings from Option 4. (524,863 + 84,460) – (524,963 – 401,941). These values are found in ERG's Industry-Level Baseline document [ERG, 2019a]

EPRI's pollution reduction estimating approach is documented in Appendix G.

18 FGD Wastewater – Other Technologies

Commenter Name: Donald Shattuck
Commenter Affiliation:
Document Control Number: EPA-HQ-OW-2009-0819-8287-A1
Comment Excerpt Number: 1

Comment Excerpt:

This letter is to bring to the attention of the EPA another technology for consideration that is more effective, less complicated, and less expensive than the technologies considered in this regulation development. SMI-III®/SeleniumZero is a patented modified iron media developed to remove selenium and other contaminants from water. It is a granular media consisting of porous, solid grains that are used as a chemical adsorbent and/or reductant. SMI-III® removes both selenate and selenite forms of selenium from a variety of waters, to concentrations below the 2 micrograms / liter (µg/L) detection limit. The total adsorption capacity of SMI-III® for selenium will depend upon empty bed contact time, pH and other water quality parameters. SMI-III® will also remove contaminants such as arsenic, nitrate, copper, trichloroethylene (TCE), mercury, and hexavalent chromium.

Sulfur Modified Iron (SMI) is a patented modified iron media developed to remove selenium and other contaminants from water. It is a granular media consisting of porous, solid grains that are used as a chemical adsorbent and/or reductant. SMI removes both selenate and selenite forms of selenium from a variety of waters, to concentrations of less than 2 micrograms per liter detection limit. Pilot studies should be conducted for final determination/confirmation of design and removal capacity.

The water quality should meet the following conditions. The preferred pH should be between 5 – 9. The pH can be adjusted to meet these requirements. The dissolved oxygen should be as low as possible. Suspended solids (SS) should be below 1.0 NTU with no oxidants such as chlorine, hypochlorite, ozone, peroxide, ferric chloride, permanganate, chloramines, or other oxidants. The water cannot contain any organic chemicals.

The following table presents results from actual full-scale installations.

Table 1: SMI Treatment Systems

Item	Parameter	Plant 1	Plant 2	Plant 3	Plant 4
1	Scale of system	Full-scale	Full-scale	Full-scale	Full-scale
2	Year of construction	2013	2017	2018	2019
3	Location of system	WV	CA	VA	MD
4	System capacity	200 gpm	40 gpm	600 gpm	50-100 gpm
5	Influent Selenium Concentration (mg/L)	0.025	1.5	0.060	0.030
6	Influent Selenium Speciation	Selenate	Selenate, Selenite & Selenocyanate	Selenate	Selenate
7	Effluent Target Selenium Concentration (mg/L)[1]	0.0046	0.0046	0.0046	0.0046
8	Client	Coal mine	Refinery	Power plant	Power plant
9	Market sector	Mining	Oil & gas	Power generation	Power generation

[1] Presented in this row is the target effluent concentration. The actual measured concentrations were in the microgram/L level or non-detect.

The proposed regulation is requiring a BAT effluent limitation of 76 µg/L selenium. This is 15 times less stringent that what the SMI Water installations have been required to meet, which was 4.6 µg/L. All of the SMI Water installations performed at a level significantly less than the target effluent concentration.

Also, I am attaching some additional lab results that show the ability of this technology to meet and exceed the proposed requirements. This technology needs to be included in the final regulation as a possible solution for individuals affected by this regulation.

Commenter Name: Regina Rodriguez, Ph.D.
Commenter Affiliation: Carbonxt
Document Control Number: EPA-HQ-OW-2009-0819-8490-A1
Comment Excerpt Number: 1

Comment Excerpt:

On the basis of current technologies, costs associated with these technologies, and timeframe of implementation, Carbonxt believes that "Activated Carbon Adsorption" can be referred to by the EPA as a possible technology for use of treating mercury in wet flue gas desulfurization (WFGD) wastewater regulated by the ELGs. Activated carbon injected directly into the WFGD slurry has been shown by Carbonxt and others to effectively remove mercury from the WFGD wastewater as good as or better than chemical precipitation. Costs associated with activated carbon injection into the WFGD for mercury control are also typically much lower than chemical precipitation. Furthermore, this technology is currently being used and can be easily added or retrofitted to a utilities already existing system train with minimal capital costs and footprint. Because of the current use and ease of implementation, Carbonxt believes the additional two (2) years for implementation proposed by the EPA may also be unnecessary.

Commenter Name: Regina Rodriguez, Ph.D.
Commenter Affiliation: Carbonxt
Document Control Number: EPA-HQ-OW-2009-0819-8490-A1
Comment Excerpt Number: 4

Comment Excerpt:

Alternatively, Carbonxt, and other activated carbon companies, have shown that the injection of powdered activated carbon (PAC) into the WFGD, is effective at removing mercury and present significant cost savings as compared to chemical precipitation or other technologies. For the purpose of ELG compliance, Activated carbon can in some cases be very effective in the removal of mercury from WFGD wastewater. The long residence times of activated carbon in the WFGD, relatively lower temperatures, and the avoidance of competing air phase species, play a role in the efficiency of the material.

Carbonxt has successfully patented this method by two US Patents (US 9,089,816 B2 and US 9,849,420 B2) as well as two additional patents pending on sorbents and systems for direct implementation of activated carbon into the WFGD slurry. The basis of these patents lie in blending of engineered activated carbon and non-halogen additives to provide better performance. However, other activated carbon companies have marketed their products for this application as well and the market can shift from air phase injection to liquid phase. The Carbonxt process will hereafter be referred to as Cxt-WetJect™.

Cxt-WetJect™ relies on the injection of the activated carbon either directly into or upstream of the WFGD without particulate removal as seen in Figure 1. This allows for the particles to enter the WFGD slurry where adsorption of mercury occurs. The Carbonxt non-halogenated additive converts mercury from the air phase to the liquid phase where it enters the slurry water. This process is very similar to air phase halogen additives, without additional risks to accumulation and halogen discharge in the wastewater effluent. In the slurry water, the activated carbon is continuously recirculated providing long contact times and efficient removal of mercury to levels of non-detect. There have been minimal effects to byproduct sales (gypsum and fly ash) or other WFGD conditions such as pH or ORP observed in pilot and full scale testing done by Carbonxt.

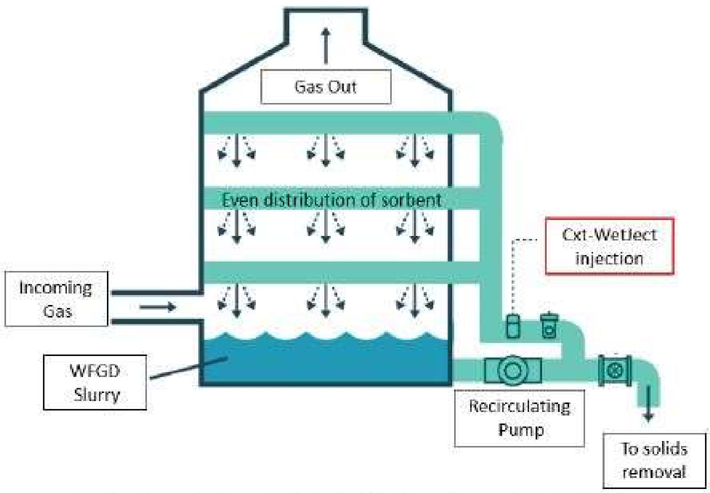

Figure 1. Implementation of Cxt-WetJect or other activated carbon injection systems. These require minimal capital and have shown minimal effect to plant operations.

In a full-scale demonstration, Cxt-WetJect™ both reduced mercury emissions in the air and liquid phase and allowed for flexibility in the unit operations, resulting in a potential cost savings upwards of $12 million annually (cost savings will be further discussed below). The conditions of the demonstration is summarized in Table 1. The WFGD slurry analysis post injection indicated lower dissolved mercury concentration in the WFGD slurry down to non-detect, despite an increase in mercury coal content as shown in Table 2.

Table 1. Cxt-WetJect™ Full-scale Demonstration

Case Study	
Configuration: • 3 units: 1600 MW total • Brominated coal additive • WFGD chemical precipitation	**Strategy before Carbonxt:** • High mercury variation in coal, constant monitoring • Concern: Low response time for chemical precipitation
Carbonxt Proposal	
• Inject oxidizing, non-halogenated Cxt-WetJect™, directly into the WFGD • Monitor response time, air and liquid phase mercury concentration, gypsum quality, water chemistry.	

Per the utility's feedback after the demonstration, Cxt-WetJect™:

- Reduced mercury air emissions within 30 minutes.
- Lowered mercury concentration in the WFGD wastewater to a level within ELG compliance.
- Steadily controlled air phase mercury emissions to meet air phase compliance.
- Reduced total costs compared to current chemical precipitation.
- Eliminated concerns regarding plant balance (i.e., pH and ORP changes).
- Generated potential cost savings of $12 million per year.

Table 2. WFGD Slurry Analysis

WFGD Slurry Analysis			
Collection Point	**Parameter**	**Day 1 Baseline**	**Day 3 Cxt-WetJect**
Coal	Hg Coal Content (ppb)	84	132
Slurry Bleed	Dissolved Hg (ng/L)	490	< 30 ng/L
	ORP (mV)	224	192
	pH	6.14	6.25

<u>Costs of Activated Carbon Technology (Cxt-WetJect™):</u>

Costs associated with Cxt-WetJect™ can be much lower than alternative technologies. Three factors that allow for lower costs include: 1) lower cost of the product use itself; 2) high efficiency and resilience allows for the use of lower cost coal (higher mercury/ sulfur content); and 3) potential sale of fly ash and gypsum.

Based on sourced bids from contractors and Carbonxt engineering, capital equipment costs associated with installation of a slurry injection system can range from $115,000 to $150,000 depending on sophistication of the equipment. These costs include fabrication of equipment and installation. Footprint of the equipment is comparatively small as Carbonxt equipment (Figure 2) is no larger than a standard shipping container and is mobile (mobility allows for intermittent injection of PAC to the WFGD and use of a single system across multiple units at a power station). Additionally, plants currently operating activated carbon injection in the air phase for mercury control can retrofit their current equipment to accommodate injection into the WFGD by changing the injection location.

Figure 2. Carbonxt pilot test equipment. The only plant requirements are a source of water, and electricity. Maintenance includes replacing the bag of activated carbon as needed. Typical change out rates are every 1-2 days.

Yearly operating costs associated with Cxt-WetJect™ can be lower than other technologies depending on usage requirements. Current market value for a system operating per year range from \$197,000 to \$854,000. While this is a rather large range, the assumption here is that the plant operates at full load, 24 hours a day, for 365 days in the year. Carbonxt has demonstrated that long residence times allows for the intermittent injection of Cxt-WetJect™ rather than continuous injection at maximum load. A more realistic approach would be 330 days operating at 12-16 hours per day; this could potentially reduce operating costs by 50% or more. In comparison, a chemical precipitation system along with the necessary bromine addition to coal can range from \$635,000 to \$931,000 for the same electric generating unit (EGU).

Cost savings associated to fuel use also contribute to very high cost savings. The effectiveness of Cxt-WetJect™ allows for EGUs to purchase and burn coals with higher mercury and sulfur content. These coals are significantly more economically favorable for EGUs and the effectiveness of the WFGD to remove sulfur along with activated carbon to remove mercury negates the increased load. Cost savings associated with the EGU in the full scale demonstration above, allowed for this fuel source change and lead to an estimated cost savings of \$12 million per year

<u>Market Strategy</u>

In order to enter the market and supply Cxt-WetJect™, Carbonxt has identified two target customers. While MATS compliance is currently being regulated, the introduction of ELGs will cause a shift in mercury emission routes (i.e., remove mercury from the air phase and discharge to the liquid phase). Pilot studies presented below at each of the target EGU configurations showed both MATS compliance and cost savings compared to presently used configurations, while full scale demonstration data presented in the sections above, show the effectiveness of Cxt-WetJect™ in liquid phase mercury capture.

Target 1: EGUs Utilizing Chemical Precipitation

Target EGUs utilizing chemical precipitation technologies for air phase Mercury and Air Toxic Standards (MATS) compliance. The goal is to turn off the chemical precipitation completely and demonstrate MATS compliance performance using Cxt-WetJect™ technology. Carbonxt was able to prove this approach during a 2016 testing opportunity at an eastern US utility.

At the time, the plant was burning a high mercury content coal and struggling to meet compliance with scrubber additive rates maxed out at 10 gph. WetJect™ was turned on at an initial rate of 100 lb/hr, to build a concentration of Cxt-WetJect™, for the first 3 hours then kept at a maintenance mode of 12 lbs/hr. Stack emissions immediately decreased by 60% as seen in Figure 3, meeting the plant's target limit of less than 1.0 ug/m^3. (Compared to typical activated carbon injection rates for air phase mercury that can exceed 500 lbs/hr.)

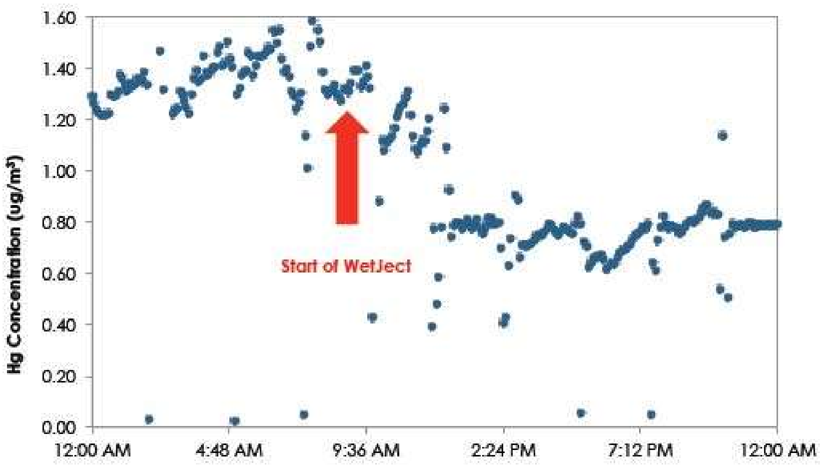

Figure 3. Cxt-WetJect™ effects on air phase mercury

Figure 3 above demonstrates Cxt-WetJect™'s ability to meet MATS compliance, as a direct comparison to chemical precipitation and provides an even broader market to enter as Cxt-WetJect™ is effective at both air phase and liquid phase mercury removal. This could allow Cxt-WetJect™ to be implemented at EGUs currently relying on chemical precipitation for MATS compliance.

Target 2: EGUs with $CaBr_2$ addition and air phase PAC injection

The second phase of our market entry strategy would involve targeting EGUs that utilize $CaBr_2$ on the coal and that employ air phase powdered activated carbon (PAC) injection. The goal would be to replace $CaBr_2$ and activated carbon injection with Cxt-WetJect™. This comparison of CxtWetJect™ to air phase PAC injection was demonstrated at 2017 test at a Midwestern USutility, however $CaBr_2$ addition was used in both.

This utility's approach to MATS compliance was to inject a highly brominated PAC at a preparticulate collection location at an average rate of 110 lb/hr. Occasionally, the EGU would increase the ACI rate to 300 lb/hr when there are significant mercury spikes. In this pilot test, Cxt-WetJect™ outperformed the air phase brominated activated carbon injection by approximately 30%.

Figure 4 highlights the cumulative potential cost savings associated with Cxt-WetJect™ in comparison to air phase injection of brominated PAC at this EGU. Due to the high injection rates of the PAC, the EGU does not qualify for fly ash sales. This analysis does not take into account the revenue from potential fly ash sales that the plant may have been able to realize (estimated around an additional $500,000 per year).

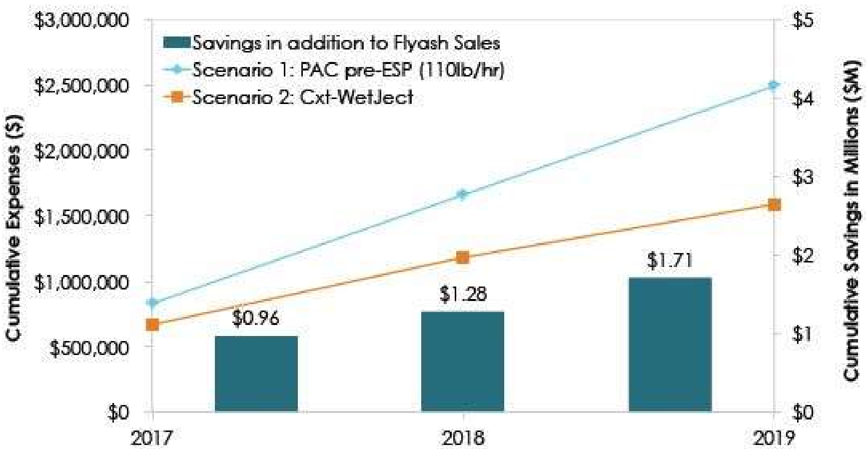

Figure 4. Expenses and savings associated with brominated activated carbon injection and Cxt-WetJect™

Overall, Carbonxt is confident that the Cxt-WetJect™ technology could be piloted and implemented at multiple power plants within the next 12 months should the product be licensed to an appropriate company and/or if Carbonxt devoted additional resources to the commercialization of this technology.

Commenter Name: Regina Rodriguez, Ph.D.
Commenter Affiliation: Carbonxt
Document Control Number: EPA-HQ-OW-2009-0819-8490-A1
Comment Excerpt Number: 5

Comment Excerpt:

Carbonxt believes that the above demonstrations and market strategy are enough basis for consideration of Activated Carbon Adsorption as a technology the EPA should deem adequate for mercury removal in the proposed ELG rulings. Carbonxt and others have been utilizing activated carbons in the industry for years and these results show its effectiveness for mercury removal in the WFGD wastewater. This would also provide EGUs with long term operational cost savings potentially in the millions of dollars per year range when compared to other technologies. As injection of activated carbon into the WFGD has both been piloted and implemented, the additional two years needed for compliance proposed may not be necessary with the guidance of the EPA.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 6

Comment Excerpt:

3. The EPA's technical evaluation should consider the efficiency and cost effectiveness of combining wastewater treatment technologies, specifically membrane filtration and thermal technologies.

Traditional systems of filtering water and treating with reverse osmosis are proven and cost effective up to concentration levels in the range of 80,000 ppm total dissolved solids. RO treatment cost increases rapidly and performance declines when the concentration target is increased. The cost of thermal technologies to distill or evaporate wastewater is significantly less sensitive to concentration targets up to about 300,000 ppm total dissolved solids and RO is less expensive than thermal technologies at lower concentration targets. (See table on page 3 above.) Because RO and thermal technologies have progressed to higher technology readiness levels for FGD wastewater since the 2016 ELGs publication, the combination of the technologies (and possibly others) should be favorably considered in the 2019 proposed ELGs.

Not all brine concentrators require a softening pretreatment step suggested on page 29 of the proposed rule. Concentrated wastewater is sometimes sent to a crystallizer as stated, but brine encapsulation is generally more cost effective.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 10

Comment Excerpt:

Thermal evaporation, on the other hand, has many operational issues that severely limit its application, as evidenced by the fact that very few facilities have chosen to invest in this technology. Nevertheless, EPA should retain the option of using thermal evaporation as a possible voluntary incentive program approach.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 64

Comment Excerpt:

B. Thermal Evaporation Technologies are Not BAT for FGD Wastewater Due to Significant Costs and Operational Challenges.

UWAG also agrees with EPA that thermal evaporation technologies are not BAT for FGD wastewater. The treatment process for FGD wastewater using thermal evaporation technologies involves three steps: chemical precipitation (using hydroxide precipitation, sulfide precipitation, and iron co-precipitation), softening, and a falling-film evaporator (also known as a brine concentrator). In the 2015 rule, EPA decided it would not be appropriate to use thermal evaporation as the BAT technology basis for FGD wastewater because of the high costs associated with meeting limits based on this technology. 80 Fed. Reg. at 67,852. Since the 2015 rule, costs have decreased to some degree, and EPA has collected information from approximately 10 pilot studies implementing five different thermal technologies and full-scale installations at six facilities. See 84 Fed. Reg. at 64,634. Although new thermal technologies have been tested and, in some cases, used at full-scale, EPA concludes that the costs are still three to five times higher than the other regulatory options. Id. Therefore, similar to its approach in 2015, EPA proposes not to establish BAT limitations based on evaporation technology.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 65

Comment Excerpt:

1. There are Numerous Challenges Associated with Operating Thermal Evaporation Technologies

While UWAG supports and agrees with EPA's proposal, in addition to the cost concerns, research on and experience with thermal evaporation systems demonstrate some significant operational issues and uncertainties when used to treat FGD wastewater. Much of the uncertainty is due to the high variability in FGD wastewater constituents. A research paper[102] notes:

Scrubber effluent chemistry is complex in that a large number of elements are present and the effluent composition constantly varies with coal and limestone composition. Important process liquid characteristics that affect corrosivity of typical ZLD materials include chloride concentration, pH, dissolved oxygen, and fluoride concentration.

Nebrig, et al. (2011) at 10. Because FGD wastewater is so corrosive, engineers evaluating thermal technologies have to either choose exotic (and expensive) metal components or plan for continual replacement of parts and the associated downtime for repairs. Corrosion will eventually occur even where the most corrosion-resistant (and costliest) metals are used. In its 2015 Response to Comments, EPA agreed with this characterization and noted that "exotic alloys are needed in the construction of an evaporation system due to the corrosive nature of the FGD wastewater."[103] As EPA acknowledged, "the system must be manufactured with titanium alloys to withstand high chloride concentrations in the concentrated FGD wastewater and these types of alloys can add capital expense to the system and also O&M costs associated with replacement parts needed for maintenance."[104] Thus, even when an evaporation system is operating without major upsets, it will require extensive and continual maintenance.

As UWAG outlined in its comments on the 2015 rule, there are a number of challenges associated with operating and maintaining a thermal evaporation treatment system, most of which EPA acknowledged in its 2015 Response to Comments.

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[102] Nebrig, H.A., X. Teng, and D. Downs, "Preliminary Assessment of a Thermal Zero Liquid Discharge Strategy for Coal-Fired Power Plants," presented at the International Water Conference, Nov. 13-17, 2011 ("Nebrig et al. (2011)").
[103] 2015 Response to Comments, at 6-41.
[104] Id.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 66

Comment Excerpt:

a. Maintaining Scrubber Blowdown Consistency is Difficult Under Some Conditions.

Depending on the type of coal being used, the salts created in the thermal evaporation process may require a blowdown to control the level of highly soluble, high boiling point salts. Brine concentrators and ultimately the crystallizers are very sensitive to chemistry. The release of higher than expected species, or changes in salts, may increase the equipment tube temperatures and foul the heat transfer surfaces of the brine concentrator. The brine concentrator must then be taken out of service and hydro-blasted to clean the scale from the heat transfer surfaces to avoid tube overheating and failure.

b. Maintaining Crystallizers is Also Difficult Due to Many Operational Variables.

Crystallizers take the brine blowdown from the brine concentrator, add heat via a heat exchanger using plant steam, and form crystals that are dewatered and sent to a landfill. Again, flow variations, chemical or constituent variation, the amount of heat added to the system, circulation rates, and numerous mechanical elements such as tank size, finish on the tank, internals, and the types of pumps that are used in the system can and will have serious impacts on the success of this final step. Thus, maintaining the crystallizer with the number of variables that change constantly is very challenging.[105]

c. Thermal Evaporation Systems Have a Large Parasitic Load.

The crystallizer is the largest user of energy in this process because it must evaporate the brine concentrate from a concentrated solution to produce a slurry that can be dewatered. Nebrig et al. (2011) at 3. A system designed to concentrate 60 gpm of wastewater with 95 percent recovery has been reported to require a 350 hp mechanical vapor compressor for operations. EPA has estimated, based on data obtained from vendors, that the energy requirements for an evaporation system are approximately 110 kW/100 gallons treated.[106]

d. Thermal Evaporation Systems Need Large Amounts of Chemicals.

As the FGD blowdown slurry stream reaches the first section of the physical/chemical (“P/C”) equipment, the system operators add large amounts of chemicals to begin chemical precipitation, conditioning, and concentration of the blowdown stream. This step is essential for reducing the levels of calcium, magnesium, and other hardness-producing ions and to lower the scaling potential of the wastewater prior to higher temperature processing.

Each reaction in the P/C portion of the treatment system is sensitive to the process parameters of the system. Changes in temperature, concentrations, and flow rate pose difficult challenges to P/C performance. This effect cascades through the P/C, changing the pH and the quantity of coagulants and polymers used to capture the metals.

The process to soften the FGD wastewater consumes a large amount of lime and soda ash. Nebrig et al. (2011) at 5. EPA agreed in its 2015 Response to Comments that an evaporation system capable of treating 410 gpm FGD wastewater with 40,000 ppm chlorine in the water would require as much as 40 tons of lime and 80 tons of soda ash per day.[107] This is equivalent to approximately five to six trucks of lime and soda ash per day, assuming 25 tons per truck load.

e. Thermal Evaporation Systems Produce Large Amounts of Sludge.

The addition of lime and soda ash to treat FGD wastewater produces a large amount of byproduct sludge to be dewatered and disposed of offsite. One UWAG member estimated that the amount of sludge produced by the de-saturation and softening process is 105 tons per day. They also estimated that the number of daily truck loads will exceed five truckloads per day at 20 tons per truck load. As EPA noted in its 2015 Response to Comments, handling as much as 105 tons per day of additional sludge “will increase manpower, transportation and disposal costs.”[108]

f. Some Equipment Is Difficult to Maintain.

The salts produced by the crystallizer are sent to a filter press and then to a landfill. There are many types of filter presses. Some use a vacuum to remove the final moisture, and others use centrifugal force to accomplish the drying. In either case, these pieces of equipment are in a harsh environment and have frequent maintenance issues. Also, many of the instruments that are generally used for automatic process control at other water or wastewater treatment systems are not reliable for use in the extremely corrosive environments of FGD wastewater treatment due to temperature variations and high amounts of corrosive materials. These performance and maintenance issues mean the operator must be very vigilant. Each operator must interpret data, make adjustments, and then process the changes to ensure the changes are correcting the operational issue.

[105] Id. at 6-42 (EPA "agrees … that maintaining the crystallizer can be 'challenging' based on the number of changing variables.").
[106] Id. at 6-99 – 6-100.
[107] Id. at 6-98.
[108] Id. at 6-98 – 6-99.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 67

Comment Excerpt:

2. Although Thermal Evaporation Systems May Be Cost-Competitive with Membrane Filtration Technologies, They Are Prone to Operational Difficulties.

In terms of EPA's proposed limitations for the voluntary incentive program, EPA proposes to establish "membrane filtration as the technology basis because it costs less than half the cost of thermal technology." 84 Fed. Reg. at 64,637. However, EPRI's cost estimates do not support this conclusion. According to EPRI, while the capital costs for thermal evaporation technologies are higher than capital costs for membranes, membrane technologies have significantly higher O&M costs, due to the management of a larger volume of brine.[109] The need to use expensive metals and alloys in the concentrators, evaporators, and crystallizers drives up the capital cost of thermal evaporation technologies. Materials such as titanium, CD4Mcu, and Hastelloy C help reduce scaling and plugging of vessel internals, as well as corrosion. Also, due to the expected frequent outages, process redundancy will also be required, which adds significantly to the overall capital costs.

EPRI has determined, however, that O&M costs are significantly higher for membrane technologies than thermal systems. For example, where EPRI determined brine solidification and disposal costs would be approximately $20 million per year for membrane technologies, with a thermal-based approach, EPRI estimated annual O&M costs would be closer to $5 million.[110]

Thus, according to EPRI, once EPA takes into consideration the full costs of implementing membrane technologies, the economic burden posed by membranes is similar to thermal evaporation technologies in terms of annualized costs. However, as UWAG outlines above, while the costs of thermal evaporation technologies may be somewhat competitive with membrane systems, significant operational issues still remain. Therefore, for engineering feasibility reasons, thermal evaporation technologies do not qualify as BAT, even though they may be a viable technology chosen for some facilities.

[109] EPRI 2020 Comments at 4-8.
[110] Id. at 4-9.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 80

Comment Excerpt:

8. The Technology-Based Requirements Proposed in the Drinking Water Utilities' June 2018 Letter Have Not Been Demonstrated.

AWWA has claimed that all power plants can achieve ZLD of FGD wastewater, because it is a relatively small waste stream and because some facilities have implemented ZLD. ZLD, however, is not feasible industry-wide. EPA already decided in the 2015 rule that ZLD is not the best available technology for FGD wastewater because it is not economically achievable. 80 Fed. Reg. at 67,852. While research continues into ZLD options, these are undemonstrated technologies at this point. For example, as noted above, much research remains to be done before membrane filtration and paste encapsulation could be considered demonstrated technologies for FGD wastewater.

Where ZLD is planned or has already been implemented for FGD wastewater, the methods employed at these plants are applicable only on a site-specific basis. For example, nine plants evaporate FGD wastewater in evaporation ponds.[135] Thus, this technology is only feasible in arid environments, such as in the southwest, where the water evaporates. Also, some plants use deep well injection for FGD wastewater.[136] However, it is very difficult in some states to secure a deep well injection permit, and the geology at the site location may not be suitable for such a process.

[135] 2015 TDD at 7-19.
[136] Id. at 7-20.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.

Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 44

Comment Excerpt:

EPA also assumes that at least three plants will continue to operate their existing evaporation systems, which achieve zero discharge using a different technology.[164] There can be no question that evaporation systems are "technologically and economically achievable" given that they are already being used at three plants. At the very least, even if they were shown to be more expensive or less cost-effective than membrane filtration systems, they are clearly achievable at these three plants. A third option for meeting a zero-discharge standard is spray dryer absorber technology.[165]

The record thus shows that "elimination [of FGD wastewater] is technologically and economically achievable" through the use of membrane filtration or other technologies.[166] In this circumstance, the Clean Water Act unambiguously requires EPA to impose a zero-discharge standard.

[164] ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019) (showing pollution loads of zero for all FGD wastestreams treated with membrane filtration).
[165] See Sahu Expert Report at 21, 24-25.
[166] 33 U.S.C. § 1311(b)(2)(A).

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 26

Comment Excerpt:

2.4 Achieving ZLD

2.4.1 Spray Dryer Absorbers

As I have mentioned above, ZLD can be easily achieved using spray dryer absorber (SDA) technology, which is not new. Spray dryer technology, developed in the 1970s, has been used in numerous applications since that time.[63] Simply, a stream of hot flue gases is used to evaporate the FGD wastewater, leaving behind residual salts which can be captured in air pollution control equipment. Obviously, the need for the hot flue gases is minimized if the FGD wastewater flow rate is minimized – i.e., by using pre-treatment steps to minimize flows. Thus, flow minimization is always a good idea.

63 See, for example, GEA, Emission Control Technology, Spray Dryer Absorber, available at https://www.gea.com/en/products/spray-dryer-absorber.jsp

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 7

Comment Excerpt:

The thermal evaporation approach to VIP has comparable, if not lower, annualized cost compared to a membrane approach.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 32

Comment Excerpt:

4.3 **EPRI's cost estimates indicate thermal evaporation has comparable, if not lower, annualized costs relative to a membrane approach.**

EPRI evaluated the cost of thermal evaporation as a potential alternative approach to complying with the FGD wastewater VIP option. We evaluated two types of thermal treatment systems: vapor compression evaporation (VCE) plus crystallization (similar to what EPA used as the FGD VIP option in 2015) and VCE plus brine solidification (i.e., encapsulation). The costs for these options are presented in Appendices C and D, respectively. EPRI estimated the total annualized cost of membrane filtration treatment to be as much or more than thermal-based treatment. The thermal-based treatment approaches had higher capital costs than membrane-based treatment. Conversely, the membrane filtration treatment approaches had significantly higher operating costs due to larger brine volume requiring solidification and disposal. The cost comparison is shown in Table 4-3.

Table 4-3
EPRI's cost estimates of FGD thermal treatment versus membrane filtration treatment at case study plant

	Membrane Filtration Treatment		Thermal Treatment	
	Case Study 1: Chemical Softening, SWRO and Brine Solidification [a]	**Case Study 2: Chemical Precipitation, Advanced Membrane Filtration and Brine Solidification** [b]	**Case Study 3: Chemical Softening, Vapor Compression Evaporation and Crystallization** [c]	**Case Study 4: Chemical Precipitation, Vapor Compression Evaporation and Brine Solidification** [d]
Pretreatment	Chemical Softening/Clarifier	Chemical Precipitation/Clarifier	Chemical Softening/Clarifier	Chemical Precipitation/Clarifier
Volume Reduction	UF + SWRO	AMF	VCE + CRX	VCE
Peak Design Flow (gpm)	300	300	300	300
Capital Cost ($M)	102	127	143	99
Annualized Capital Cost ($M/year) [e]	9.6	12	14	9.3
O&M Flow Basis (gpm)	153	153	153	153
O&M Costs ($M per year) [g]	30	49	7.6	12
Wastewater Treatment ($M/year) [h]	15	25	6.8	5.6
Disposal ($M/year)	14	22	1.0	5.6
Lost Fly Ash Sales ($M/year)	1.2	1.2	0	0.8
Total Annualized Costs ($M/year) [i]	**40**	**61**	**21**	**21**

AMF = Advanced Membrane Filtration (several vendors)
BS = Brine Solidification (i.e., encapsulation)
CRX = Crystallizer
gpm = gallons per minute
M = million
SWRO = Seawater Reverse Osmosis
UF = Ultrafiltration
VCE = Vapor Compression Evaporator
$ = U.S. dollars
[a] 2 x 60% chemical softening, N + 1 UF, N+1 SWRO membrane, and 2 x 100% pugmill systems (Appendix D)
[b] 2 x 60% chemical precipitation, 120% AMF System, 2 x 100% pugmill systems (Appendix D)

Table 4-3 (continued)
EPRI's cost estimates of FGD thermal treatment versus membrane filtration treatment at case study plant

[c] 2 x 60% chemical softening, 2 x 60% vapor compression evaporator, and 1 x 100% crystallizer systems based on Vendor B costs (Appendix D.1.5)
[d] 2 x 60% chemical precipitation, 2 x 60% vapor compression evaporator, and 2 x 100% pugmill systems (Appendix D)
[e] Annualized cost based on a 20-year equipment life and 7% interest rate.
[f] EPRI case studies assume a capacity factor of 0.51 (see Appendix D for basis).
[g] Total O&M cost including wastewater treatment costs, disposal costs and lost fly ash sales.
[h] Wastewater treatment O&M costs including electricity, chemicals, labor, equipment maintenance, compliance monitoring, steam, cooling water, and miscellaneous unidentified cost.
[i] Total annualized cost included annualized capital cost and total O&M cost.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)

Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 65

Comment Excerpt:

C — APPENDIX: FGD WASTEWATER TREATMENT COST METHODOLOGY—VAPOR-COMPRESSION EVAPORATION/CRYSTALLIZATION

C.1 Cost estimating summary for chemical softening with vapor compression evaporation/crystallization treatment of flue gas desulfurization wastewater

C.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the cost of chemical softening with vapor-compression evaporation/crystallization (CS + VCE/CRX) treatment of flue gas desulfurization (FGD) wastewater to the steam electric industry based on EPA's industry profile [ERG, 2019a]. This technical memorandum describes the method for calculation of cost of treatment for an individual plant, the assumptions associated with the cost calculations, and the estimated costs for treatment to the steam electric industry. Table C-1 outlines the cost to the current industry to install CS + VCE/CRX treatment of FGD wastewater.

Table C-1
Treatment costs to current industry for FGD wastewater, in June 2018 dollars[a]

Treatment Option	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Annualized Cost[b] ($M per year)
CS + VCE/CRX	$11,081	$563	$1,605

[a] The cost for the industry was estimated assuming that industry plants with operating capacity factors greater than 0.60 would install a 2 x 100% redundancy CS + VCE/CRX system and the remaining industry plants would install a 2 x 60% redundancy CS+VCE/CRX system, as described in this appendix

[b] Annualized cost based on a 20-year equipment life and 7% interest rate.

$ = U.S. dollars

M = million

C.1.2 Introduction

The U.S. Environmental Protection Agency (EPA) updated the Steam Electric Power Generating effluent limitation guidelines (ELGs) through a comprehensive information collection request (ICR) and sampling at FGD wastewater treatment systems. Following the ICR, the EPA published a draft ELG rule in 2013. EPRI previously provided estimated costs for FGD wastewater treatment technologies as part of commenting on the 2013 ELG rulemaking. The ELG rule was later finalized in 2015 but is now being reconsidered for FGD wastewater. Therefore, EPRI has prepared updated cost estimates of FGD wastewater treatment technologies for commenting on the revised draft ELG rule. The treatment technologies evaluated were (1) chemical precipitation, (2) biological, (3) chemical softening followed by vapor-compression evaporation/ crystallization (CS + VCE/CRX), (4) chemical precipitation followed by vaporcompression evaporation and brine solidification (CP+VCE/BS), (5) chemical softening followed by seawater reverse osmosis (SWRO) and brine solidification (CS + SWRO/BS), and

(6) chemical precipitation followed by advanced membrane filtration (AMF) and brine solidification (CP+AMF/BS). The technologies are discussed in separate Appendices A thru D, with Appendix D addressing all of the treatment technologies that use brine solidification. The cost evaluation results for chemical precipitation, biological and CS + VCE/CRX treatment were extrapolated industry-wide.

C.1.3 CS + VCE/CRX treatment overview

This evaluation focuses on a system that uses chemical softening, evaporation, and crystallization.

The softening pretreatment needed for crystallization requires large quantities of chemicals and produces a large amount of residual solids. It consists of cold lime (or caustic) and soda ash softening to remove calcium, magnesium, and silica from the FGD wastewater, followed by pH neutralization using sulfuric acid. Neutralization is required to degas the wastewater in a deaerator before reaching the VCE processes. For the EPRI evaluation, the pretreatment equipment selected included mix tanks, clarifiers, neutralization tanks, process pumps, and filter presses to remove the solids. Some recirculation of the softened water was used as make-up water for the lime and soda ash feed slurries.

For EPRI's design, the primary evaporative stage includes a vapor-compression, falling film evaporator (brine concentrator) to compress the vapor (distillate) mechanically and heat the brine. This type of evaporator is more energy efficient because the latent heat of evaporation energy is reused, thereby reducing energy requirements as compared to a steam-driven brine concentrator, which was not considered. The vapor-compression evaporator, however, cannot alone reach the crystallization temperature required. A vapor-compression crystallizer was assumed to be used downstream of the evaporator to further concentrate the evaporator brine and to meet the higher boiling requirements required as salinity increases. This combination of vapor-compression evaporator followed by crystallizer provides a favorable cost and energy efficient design solution.

This CS + VCE/CRX alternative does not produce liquid waste streams requiring discharge or landfilling, and results in a crystallizer salt cake. Since calcium chloride and magnesium chloride salts cannot crystallize at a temperature that is readily achieved, crystallization requires softening pretreatment to remove calcium and magnesium. This crystallization process produces a sodium chloride and sodium sulfate salt cake. Final residuals of the CS + VCE/CRX process consist of dewatered softener sludge and salt cake solids requiring disposal in a lined landfill.

A block flow diagram representing the configuration of the CS + VCE/CRX system assumed for cost estimating is shown in Figure C-1. The key aspects of this system are:

- **Treatment objective** – Elimination of wastewater discharge by means of thermal treatment and evaporation of water. Resulting solids from softening sludge and salt cake are disposed to a landfill. Softening pretreatment is required to reduce crystallizer operating temperature and corrosivity.

- **Key equipment** – Equalization tank, softening reaction tanks, softening clarifiers, neutralization tank, evaporator feed tank, chemical feed systems, vapor-compression evaporator system, vapor-compression crystallizer, temporary brine storage tank, distillate/reuse tank, and filter presses.
- **Wastes** – The final residuals are softener solids and salt cake solids, both requiring disposal in a lined landfill.

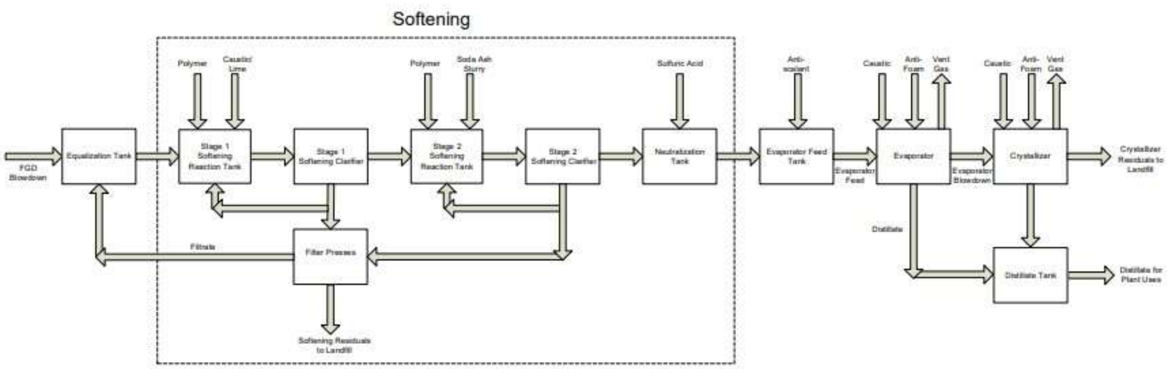


Figure C-1
Chemical softening with evaporation/crystallization system

C.1.4 Conceptual design basis

The design basis for the cost estimate is described in this section.

C.1.4.1 Flow rate basis

Flow capacity is a key factor in the cost of many treatment components. Peak flow rate is the main consideration in sizing equipment. Average flow rate has a large impact on operating cost elements such as chemical feed, waste disposal, and electricity.

Conceptual costs were estimated for two system sizes, a small model plant flow rate and a large model plant flow rate. These two sizes are:

- "Small flow rate" system = FGD blowdown flow rate of 300 gallons per minute (gpm)
- "Large flow rate" system = FGD blowdown flow rate of 600 gpm

Conceptual design cost estimates were prepared for these two flow capacities and for two different levels of equipment redundancy:

- "2 x 100%" = two identical trains at 100 percent capacity for all equipment, including the evaporator and crystallizer systems
- "2 x 60%" = two identical trains at 60 percent capacity for all equipment, except for the crystallizer which is sized for 100 percent capacity to service both trains.

Capital costs for the CS + VCE/CRX technology option were calculated for four theoretical case study plants based on FGD blowdown rate and assumed redundancy. A flow rate basis was chosen because the size of the power plant (in megawatts [MW]) does not capture cost of treatment, because factors such as coal chloride concentration and water recycling play a large role in determining FGD water flow rate.

Table C-2
Flow rate and redundancy options considered

Parameter	Small System		Large System	
Flow rate (gpm)	300	300	600	600
Flow rate (MGD)	0.43	0.43	0.86	0.86
Equipment Redundancy:				
CS System	2 x 100%	2 x 60%	2 x 100%	2 x 60%
VCE System	2 x 100%	2 x 60%	2 x 100%	2 x 60%
CRX System	2 x 100%	1 x 100%	2 x 100%	1 x 100%

The estimated capital and O&M costs for these case studies were used to develop industry-wide cost estimates as described in Section C.1.9.

C.1.4.2 Feed water quality characteristics

Feed water chemistry was assumed to be the same as EPA's reported "average pollutant concentrations in untreated FGD wastewater" [EPA, 2015]. This water quality is referred to as the original feed water chemistry in Table C-3. EPA's definition of untreated FGD wastewater appears to most closely align with FGD blowdown from a plant that burns eastern bituminous coal.

EPRI used OLI Studio: Stream Analyzer (a commercially available computer software program used to model aqueous systems) to evaluate the original water chemistry assumed by EPA. The total parameter concentrations for this water were input to the model. The reconciled feed water chemistry detailed below reflects the OLI Studio: Stream Analyzer adjusted water quality, which varies from the original feed water quality primarily in dissolved calcium and sulfate concentrations. Adjustment to the assumed water quality was necessary to reconcile the stream for electroneutrality (i.e., charge balance). The model makes minor adjustments to other ion concentrations if needed. EPRI assumed a default temperature value of 95 degrees Fahrenheit (°F) for the feed water. Based on the water chemistry input, the model calculated the pH of the feed water to be 6.4.

This evaluation assumes no pretreatment of FGD blowdown upstream of the CS + VCE/CRX system. A total suspended solids (TSS) loading value of 13,315 milligrams per liter (mg/L) was determined by the model for the reconciled feed water under equilibrium conditions. The assumed concentration of 13,315 mg/L TSS in this evaluation is slightly less than EPA's reported typical TSS concentration of 14,500 mg/L in FGD scrubber purge [EPA, 2015].

EPRI also used OLI Studio: Stream Analyzer to model complete lime and soda ash softening of the FGD feed water. The results of the simulated softening assumed a clarifier effluent of 30 mg/L TSS and neutralization to pH 5.5 suitable for deaerator feed.

Table C-3
Water chemistry

Parameter	Original Feed Water Chemistry [a]		Reconciled Feed Water Chemistry [b]	
Temperature (°F)	NR		95	
pH	NR		6.4	
Density (g/mL)	NR		1.02	
Total suspended solids	14,500		13,315	
Total dissolved solids	33,300		25,310	
Parameter Concentrations	**Total (mg/L)**	**Dissolved (mg/L)**	**Total (mg/L) [c]**	**Dissolved (mg/L)**
Calcium	3,290	2,050	3,290	667
Magnesium	3,250	3,370	3,250	3,250
Sodium	2,520	276	2,520	2,520
Barium	2.75	0.284	2.75	0.009
Iron	566	0.100	566	0.00005
Manganese	85.7	106	85.7	85.7

Table C-3 (continued)
Water chemistry

Parameter	Original Feed Water Chemistry [a]		Reconciled Feed Water Chemistry [b]	
Parameter Concentrations	**Total (mg/L)**	**Dissolved (mg/L)**	**Total (mg/L) [c]**	**Dissolved (mg/L)**
Aluminum	331	1.47	331	0.0003
Sulfate	13,300	NA	16,116	9,818
Chloride	7,180	NA	7,180	7,180
Nitrate as N	91.4	NA	91.4	94.1
Boron	242	266	242	242
Phosphorus	4.02	NA	4.02	4.02
Arsenic	0.507	0.0071	0.507	0.507
Cadmium	0.127	0.128	0.127	0.127
Chromium	1.27	0.00417	1.27	0.0041
Cobalt	0.245	0.206	0.250	0.250
Copper	0.673	0.0201	0.673	0.673
Cyanide	0.733	NA	0.733	0.733
Lead	0.315	0.001	0.315	0.315
Nickel	1.49	0.973	1.49	0.000015
Mercury	0.289	0.0072	0.289	0.289
Selenium	3.13	1.13	3.13	3.13
Silver	0.0082	0.001	0.0082	0.0082
Zinc	4.11	1.58	4.11	0.06
Bicarbonate	NR	NR	0	0
Fluoride	NR	NR	0	0
Silica	NR	NR	0	0

[a] Original feed chemistry for total and dissolved concentrations of analytes in untreated FGD wastewater as reported in EPA, 2015, Table 6-3.
NR = Not reported.
NA = EPA reported as "Not Applicable. Samples were not analyzed for this particular analyte." Antimony, beryllium, molybdenum and thallium were reported at low concentrations and were not included in the model input.
[b] When reconciling the water chemistry data using OLI Stream Analyzer, small adjustments to the concentrations might occur for things such as ion balancing and speciation of certain components. The software model also predicts the partitioning of ions in the dissolved and solid phases under equilibrium conditions.
[c] Total concentration is shown as the sum of aqueous and solid phase concentration values reported by the model.
°F = degrees Fahrenheit
g/mL = grams per milliliter
gpm = gallons per minute
mg/L = milligrams per liter
MGD = million gallons per day

C.1.5 Cost development methods

C.1.5.1 Equipment cost assumptions

Equipment costs were provided by two equipment vendors with experience providing systems for similar applications, Vendor A and Vendor B.

C.1.5.1.1 Vendor A

Using the feed chemistry provided in Table C-3, Vendor A provided quotations for the total installed capital cost for a system consisting of partial softening, seeded slurry brine concentration, and mixed salt crystallization for the flow options considered.

Upstream and downstream equipment from the evaporator and crystallizer system, including evaporator feed handling equipment, chemical feed equipment, softening process equipment, and solids dewatering equipment were part of the quotation. Vendor A estimated a packaged system cost that included all process and mechanical equipment, site work (with allowance for brownfield construction), concrete foundations, interconnect piping, electrical wiring to and including the motor control center (MCC), new electrical feeder to the MCC, instrumentation, controls, metals, finishes, and a process building to support all equipment. The total installed cost estimate also included equipment freight, general contractor general and administrative costs and profit, onsite consumables, construction equipment, engineering, services during construction, startup, commissioning and start-up spare parts, and a 10 percent contingency for all cost categories [2018/2019, personal communications].

EPRI separately estimated the costs for additional equipment outside the vendor's package which consisted of equalization tank storage upstream of the vendor system and distillate storage/reuse tank downstream of the vendor system. EPRI has also assumed that the mixed salt cake generated from the partial softening process will contain hygroscopic $CaCl_2$ and $MgCl_2$ salts, which would need to be stabilized. Correspondence with the vendor indicated that the mixed salt cake, which would be placed in supersacks, would leach. Therefore, when developing total costs for this vendor, EPRI has included the equipment costs to amend the crystallizer salt with stabilization material (fly ash and quicklime) prior to deposition in the landfill.

Because the quoted evaporator/crystallizer system was provided as a total installed cost, EPRI considered the known cost factors assumed by the vendor in quoting the total installed cost and professional best judgment in order to estimate the total equipment cost of the vendor's quoted system. Most system-wide cost factors used in the EPRI estimates (see Table A-31) were not applied to Vendor A's costs; however, the estimated total equipment cost was used to develop these additional cost factors if required. For example, general contractor bonding and insurance, permitting and owner's administrative costs were not included in the quotation, so these cost factors were applied. A cost factor of 20 percent was applied for engineering the entire treatment system to account for the higher costs of engineering for electrical infrastructure and coordination with the vendor's design package.

Further, the cost factor for miscellaneous unidentified costs (i.e., contingency) was increased from the vendor's assumption of 10 percent to 20 percent to remain consistent with other treatment technologies evaluated (chemical precipitation and biological). A detailed explanation of the cost factors used for developing capital cost estimates is provided in subsection C.1.6.2 below.

C.1.5.1.2 Vendor B

Using the softened water chemistry for the reconciled FGD water, Vendor B provided package costs for a system consisting of seeded slurry brine concentration and crystallization for the flow options considered.

Vendor B estimated costs for a “turnkey” system that included all costs within battery limits of the vendor’s equipment package. This included all process and mechanical equipment, concrete foundations, interconnect piping, instrumentation, controls, and electrical wiring to and including the motor control center (MCC). The turnkey estimate also included all labor required to install, test, and commission the evaporator/crystallizer system [2019, personal communication].

Upstream and downstream equipment from the evaporator and crystallizer system, including equalization equipment, chemical feed equipment, softening process equipment, solids dewatering equipment, and distillate storage system were not part of the turnkey design. Therefore, EPRI estimated the costs for this additional equipment. EPRI has not included equipment costs for amending the crystallizer salt with stabilization material (fly ash and quicklime) in development of Vendor B costs, since the basis for this vendor’s costs assumed complete softening (i.e., removal of calcium and magnesium) upstream of the evaporator/crystallizer system.

Because the quoted evaporator/crystallizer system is turnkey, most system-wide cost factors used in the EPRI estimates (see Table C-4) were not applied to the evaporator/crystallizer package installed equipment costs, with a few exceptions. Site work was not included in the turnkey quotation, so a cost factor was applied to the vendor package. Since only electrical wiring within the battery limits and to the MCC was provided with the vendor quotation, an industry average electrical cost factor of 22 percent was applied for the entire wastewater treatment system to account for new electrical supply infrastructure costs upstream of the MCC. Similarly, a cost factor of 20 percent was applied for engineering the entire treatment system to account for the higher costs of engineering for electrical infrastructure and coordination with the vendor’s design package.

System-wide cost factors (Table C-4) were applied to all equipment outside of the battery limits of the vendor’s provided evaporator/crystallizer system.

General contractor bonding and insurance, permitting and owner’s administrative costs were not included in the vendor’s quotation, so these cost factors were also applied to the vendor package.

A cost factor of 20 percent was applied for miscellaneous unidentified costs consistent with other treatment technologies evaluated (chemical precipitation and biological). A detailed explanation of the cost factors used for developing capital cost estimates is provided in subsection A.4.6.2 below.

C.1.6 Capital cost assumptions

C.1.6.1 Classification of estimate

This memorandum presents Class 4 cost estimates, generally defined as study- or feasibility level estimates, for total installed costs (+50 percent to -30 percent accuracy). A definition of cost estimate classifications is presented in Appendix A. Vendor-developed costs were used for the major unit process systems (for example, evaporator and crystallizer systems), considering the assumptions indicated by the vendor quote. Support equipment items (not included with major systems) were estimated based on costs supplied from other equipment vendors, internal databases, and chemical suppliers. Vendor-developed costs and support equipment costs were summed to calculate a purchased equipment cost (PEC).

C.1.6.2 Cost model factors

System-wide cost factors were applied to develop the cost estimate (Table C-4). Values within the suggested ranges in Table C-4 are typically used in estimating costs of wastewater treatment plants. The mid-point of the suggested range for each cost factor was used to estimate costs for this evaluation; however, a 25 percent factor was applied for piping assuming high-grade alloy would be installed (typical range of 6 to 8 percent is for conveyance piping), and a 15 percent factor was applied for miscellaneous metals and finishes assuming fiberglass materials would be installed due to the corrosive environment. A 7 percent factor was chosen for client administrative and overhead assuming that these costs include early engineering and geotechnical

Table C-4
Cost factors

Additional Cost Items	Typical Suggested Range (%)		Value Used (%)	Rationale for Selected Value
Site work	3.0	5.0	4.0	Mid-point of range
Concrete	15.0	20.0	17.5	Mid-point of range
Piping	6.0	8.0	25.0	Higher than range; assumes installation of high-grade alloy
Miscellaneous metals, finishes	5.0	15.0	15.0	Maximum of range; assumes high corrosion environment and installation of fiberglass materials
Mechanical, heating/ventilation/air conditioning	5.0	10.0	7.5	Mid-point of range
Electrical	14.0	30.0	22.0	Mid-point of range
Instrumentation and control	10.0	20.0	15.0	Mid-point of range
General contractor general conditions	11.0	14.0	12.5	Mid-point of range
Bonding and insurance	2.7	3.0	2.9	Mid-point of range, rounded up
General contractor overhead and profit	14.1	14.4	14.3	Mid-point of range, rounded up
Miscellaneous unidentified cost	10.0	30.0	20.0	Mid-point of range

Table C-4
Cost factors

Additional Cost Items	Typical Suggested Range (%)		Value Used (%)	Rationale for Selected Value
Site work	3.0	5.0	4.0	Mid-point of range
Concrete	15.0	20.0	17.5	Mid-point of range
Piping	6.0	8.0	25.0	Higher than range; assumes installation of high-grade alloy
Miscellaneous metals, finishes	5.0	15.0	15.0	Maximum of range; assumes high corrosion environment and installation of fiberglass materials
Mechanical, heating/ventilation/air conditioning	5.0	10.0	7.5	Mid-point of range
Electrical	14.0	30.0	22.0	Mid-point of range
Instrumentation and control	10.0	20.0	15.0	Mid-point of range
General contractor general conditions	11.0	14.0	12.5	Mid-point of range
Bonding and insurance	2.7	3.0	2.9	Mid-point of range, rounded up
General contractor overhead and profit	14.1	14.4	14.3	Mid-point of range, rounded up
Miscellaneous unidentified cost	10.0	30.0	20.0	Mid-point of range

Table C-4 (continued)
Cost Factors

Additional Cost Items	Typical Suggested Range (%)	Value Used (%)	Rationale for Selected Value	Additional Cost Items
Engineering	15.0	25.0	20.0	Mid-point of range, (assumes 15% for design, 4% for services during construction, and 1% for start-up and operator training)
Client Administrative and Overhead	3.5	3.5	7.0	Higher than range, assumes it also includes early engineering and geotechnical investigation.

C.1.6.2 Major assumptions

Major cost assumptions used to develop estimates are presented in Appendix A.

In addition, the following major assumptions for this capital cost evaluation include:

- Costs are presented in June 2018 dollars. Construction Cost Index values, as published by Engineering News Record (ENR) as of March 2019, were used to escalate costs to June 2018 pricing.
- Wastewater tie-in piping of 1,000 linear feet will be installed above grade.
- The power plant has no existing pretreatment system for the FGD wastewater.
- The basis for Vendor A's costs are partial caustic and soda ash softening, whereas the basis for Vendor B's cost are full lime and soda ash softening.
- The conceptual design includes evaporator brine storage tanks and mixers, which would be used to provide intermittent brine storage ahead of the crystallizer system.
    - Equipment for the 2 x 100 percent redundancy conceptual designs includes two 24-hour evaporator brine storage tanks and mixers. o
    - The 2 x 60 percent redundancy conceptual designs, which include only a single 100 percent capacity crystallizer, include equipment sized for two weeks of storage capacity. This allows for intermittent evaporator brine storage when the crystallizer is not operating. This conceptual design also includes an allowance for crystallizer critical spare parts.

C.1.7 Operations and maintenance costs assumptions

C.1.7.1 Cost elements

Operations and maintenance (O&M) requirements for this estimate include the following cost elements:

- Chemicals
- Utilities (electricity, steam, cooling water)
- Residuals disposal (softening solids, crystallizer solids)
- Evaporator and crystallizer cleaning
- Labor
- Equipment maintenance
- Compliance monitoring and mercury analyzer
- Miscellaneous unidentified costs (i.e., contingency)

C.1.7.2 Major assumptions

Major cost assumptions used to develop estimates are presented in Appendix A.

In addition, the following major assumptions for this O&M cost evaluation include:

- All unit costs presented in June 2018 dollars
- O&M costs are based on the Vendor B conceptual design approach, which assumed full chemical softening using lime and soda ash, followed by sodium chloride salt crystallization. Chemical costs are not included for fly ash, quicklime or Portland cement to amend the crystallizer salt slurry.
- EPRI assumed that the FGD system will operate and generate wastewater 51 percent of the time. The assumed 51 percent is based on the median gross capacity factor reported

for 2015, 2016 and 2017 at the plants listed in EPA's 2013 cost estimates. Therefore, EPRI used a plant capacity factor equal to 0.51 which was applied to the O&M quantities.

- Labor: a total of 10 full-time equivalent (FTE) operators at $49/hour, one supervisor at $76/hour, and one chemical engineer at $90/hour were assumed to staff the facility. It is assumed that the facility will be staffed five days per week.
- Chemical dosage rates based on modeling results or typical values. (Actual dosage rates could vary depending on FGD wastewater chemistry.) Chemical supply costs were assumed to be (actual costs will vary by geography, delivery method, and chemical supplier):
    - Sulfuric acid (93%) - $1.50/gallon (gal)
    - Caustic (50%) - $3.41/gal
    - Hydrated Lime - $0.09/pound (lb)
    - Soda Ash - $0.16/lb
    - Antiscalant - $17/gal o Antifoam - $17/gal
    - Polymer - $36/gal
- Chemical dosages were based on full softening pre-treatment using hydrated lime and soda ash. Either caustic or lime could be used along with soda ash for softening. The advantage of using caustic softening is the generation of less softening solids, however the unit cost of caustic is considerably higher than that of lime. Therefore, the chemical costs associated with caustic-soda ash softening are estimated to be higher than lime-soda ash softening. EPRI considered both options for chemical softening and the analysis showed that lime-soda ash softening would be the more cost-effective softening method for this assumed FGD water quality considering both chemical supply and disposal costs.
- Electricity cost of $0.0523 per kilowatt hour
- Cooling water demand was calculated assuming the water vapor mass flow rate from the evaporator deaerator is 1.5 percent of evaporator feed flow rate. Cooling water demand for the crystallizer was calculated assuming a cooling water temperature rise of 40 °F. The assumed cost for cooling water is $1.78 per 1,000 gallons.
- The mechanical vapor compression crystallizer would only require steam during startup. Steam demand was provided by one of the vendors assuming an estimated cold startup of one day per month. The cost of steam is assumed to be $10.06 per 1,000 pounds. One pound of steam was assumed to be equal to 970 British thermal units.
- EPRI has assumed that the evaporator/crystallizer system would only typically be run when the power units are operating and generating steam and FGD wastewater. Therefore, steam for startup should be available at the plant. EPRI has not included a cost for a backup secondary steam supply.
- Residuals disposal unit cost of $54/ton on a dry-weight basis, which is based on EPA's disposal costs [EPA, 2013]and escalated to June 2018 dollars. EPRI developed the unit cost assuming that 25 percent of plants would use offsite landfills and 75 percent use onsite landfills.
- All wastes were assumed to be RCRA nonhazardous solids. All landfills assumed to be lined and monitored.
- Falling-film evaporator tube cleanings and crystallizer cleanings will occur twice per year per equipment system.
- Annual equipment maintenance cost equal to 3 percent of total equipment cost.

- Compliance monitoring costs equal to the sum of chemical precipitation monitoring ($60,000) plus evaporation monitoring ($60,000).
- A 20-percent markup was applied to each O&M cost estimate for miscellaneous unidentified costs.

C.1.8 Cost estimates summary

Example cost estimates for the CS + VCE/CRX case studies are provided in the following subsections

C.1.8.1 Capital costs

Total estimated capital costs were developed for the four case study plants, based on the two design flowrates and the two equipment redundancy cases, and are provided in Table C-5. The total estimated capital cost for the 300 gpm flowrate and 2 x 60% redundancy design case were developed by calculating the average cost of the Vendor A and Vendor B case studies. The equipment costs are based on cost quotes provided by the equipment vendors. The cost model factors shown in Table C-4 were added to the installed equipment costs to obtain the total estimated capital costs for the system.

Table C-5
Summary of estimated treatment capital costs, in June 2018 dollars

	300 gpm Flow		600 gpm Flow	
Cost Element ($ thousand)	**2 x 60%**	**2 x 100%**	**2 x 60%**	**2 x 100%**
Evaporator/Crystallizer vendor package [a,b]	$20,878	$43,431	$39,000	$57,250
Support equipment				
Equalization system	$1,389	$2,353	$2,763	$4,569
Evaporator feed handling equipment	$76	$175	$183	$234
Chemical feed equipment (other than softening)	$126	$282	$277	$306
Softening equipment	$1,777	$4,055	$5,037	$7,120
Softening solids dewatering	$2,986	$6,444	$10,043	$10,936
Brine handling and storage equipment	$3,667	$0	$6,206	$0
Fly ash/lime/cement handling and mixing equipment for stabilization	$127	$0	$0	$0
Cold distillate handling and storage equipment	$366	$493	$559	$825
Freight (4%) and taxes (0%)	$1,256	$2,289	$2,563	$3,249
Subtotal – Purchased Support Equipment Cost as Delivered	**$10,936**	**$14,354**	**$26,070**	**$24,949**
Subtotal – Purchased Equipment Cost as Delivered	**$32,650**	**$59,521**	**$66,632**	**$84,489**
Additional cost items [d]				
Pre-engineered building [c]	$9,428	$9,428	$12,570	$12,570
Critical Spare Parts	$197	$0	$197	$0
Tie-in allowance [f]	$88	$88	$88	$88
Site work [g]	$1,306	$2,381	$2,665	$3,380
Piping [c]	$2,734	$3,589	$6,518	$6,237
Mechanical/HVAC [c]	$821	$1,076	$1,956	$1,872
I&C [c]	$1,640	$2,153	$3,911	$3,742
Electrical	$7,183	$13,094	$14,659	$18,587
Concrete [c]	$1,914	$2,512	$4,563	$4,366
Miscellaneous metals, finishes [c]	$1,640	$2,153	$3,911	$3,742
Subtotal – Direct Costs	**$59,601**	**$95,994**	**$117,669**	**$139,073**

Table C-5 (continued)
Summary of estimated treatment capital costs, in June 2018 dollars

	300 gpm Flow		600 gpm Flow	
Cost Element ($ thousand)	**2 x 60%**	**2 x 100%**	**2 x 60%**	**2 x 100%**
General contractor general conditions [c,d]	$4,736	$6,353	$9,639	$9,942
Bonding and insurance [d]	$1,698	$2,735	$3,354	$3,963
General contractor profit [c,d]	$5,399	$7,243	$10,988	$11,333
Subtotal – Direct and Indirect Costs	**$71,435**	**$112,325**	**$141,649**	**$164,312**
Miscellaneous unidentified cost [d]	$14,287	$22,465	$28,329	$32,862
Subtotal – Estimated Construction Cost	**$85,722**	**$134,791**	**$169,978**	**$197,174**
Engineering (design, SDC, startup, and operator training) [d]	$17,144	$26,958	$33,996	$39,435
Client administrative and overhead [d]	$6,001	$9,435	$11,899	$13,802
Permitting	$57	$57	$57	$57
Total Estimated Capital Cost ($ million)	**$109**	**$171**	**$216**	**$251**
Total Estimated Capital Cost ($ million) +50%	**$163**	**$257**	**$324**	**$376**
Total Estimated Capital Cost ($ million) –30%	**$76**	**$120**	**$151**	**$175**

[a] Vendor A provided a total installed capital cost quotation in November 2018 for a softening, seeded slurry brine concentration and mixed salt crystallization system. EPRI estimated a total cost for the vendor equipment package based on the vendor's input on their assumed direct and indirect costs, and EPRI's professional best judgment. EPRI has adjusted the vendor's quote to June 2018 dollars

[b] Vendor B provided a cost quotation for a turnkey process island (total installed cost) in June 2018, consisting of the evaporator and crystallizer systems only

[c] Included in vendor package, therefore was applied to support equipment only

[d] See Table C-4 for factors used to estimate these additional cost items.

[e] Pre-engineered building was estimated at 30,000 square feet and 40,000 square feet for the 300 gpm and 600 gpm case studies, respectively. Building was assumed to include two floors and accommodate an office, motor control center (MCC), chemicals storage, dewatering equipment and evaporator/crystallizer system.

[f] Assumes wastewater tie-in piping of 1,000 linear feet installed above grade.

[g] Includes fencing, grading, roads, sidewalks, and similar items.

$ = U.S. dollars
M = million
HVAC = heating, ventilation, and air conditioning
I&C = instrumentation and controls
SDC = services during construction

C.1.8.2 Operations and maintenance costs and quantities

The total estimated O&M costs for the system are provided in Table C-6. O&M unit quantities, and therefore costs, are based on average feed flow, water chemistry and solids loading. Therefore, the O&M costs estimated by EPRI are similar for the 2 x 60% and 2 x 100% design options. O&M costs are based on the conceptual design approach using full chemical softening with hydrated lime and soda ash. Since this concept would lead to formation of a sodium-based salt, EPRI has not included the costs for amendments (e.g., quicklime) to be mixed with the C-15 crystallizer salt. Unit costs used to develop the annual O&M cost estimates were previously presented in Section C.1.7.2.

Table C-6
Summary of treatment annual O&M costs, in June 2018 dollars

Cost Element ($ thousand per year)	300 gpm		600 gpm	
	2 x 60%	2 x 100%	2 x 60%	2 x 100%
Chemicals [a]				
Antiscalant	$11	$11	$21	$21
Antifoam	$11	$11	$23	$23
Sulfuric acid (93%)	$70	$70	$140	$140
Caustic (50%)	$24	$24	$47	$47
Polymer	$233	$233	$466	$466
Hydrated lime	$639	$639	$1,278	$1,278
Soda ash	$841	$841	$1,682	$1,682
Subtotal – Chemicals	**$1,830**	**$1,830**	**$3,659**	**$3,659**
Electricity	$505	$529	$985	$1,045
Steam	$1	$1	$1	$1
Cooling water	$334	$336	$670	$670
Residuals disposal, non-hazardous onsite landfill	$973	$974	$1,947	$1,947
Maintenance	$600	$942	$1,187	$1,378
Labor	$1,368	$1,368	$1,368	$1,368
Evaporator/Crystallizer Cleanings	$576	$970	$1,150	$1,941
Compliance Monitoring	$151	$151	$151	$151
Miscellaneous unidentified cost	$1,268	$1,420	$2,224	$2,432
Total Estimated O&M Cost ($ million/yr)	**$7,605**	**$8,521**	**$13,342**	**$14,591**

[a] Chemical costs are industry average and include an assumed national average freight. Chemicals costs will vary depending on plant location and local chemical distributors.
$ = U.S. dollars
M = million
O&M = operations and maintenance
RCRA = Resource Conservation and Recovery Act

Annual estimates for O&M quantities are presented in Table C-7. Annual estimates for O&M quantities assumed a 51 percent online factor.

Table C-7
Summary of estimated annual O&M quantities

	300 gpm		600 gpm	
Cost Element	**2 x 60%**	**2 x 100%**	**2 x 60%**	**2 x 100%**
Major Chemicals				
Sulfuric acid (93%) (gallons)	47,000	47,000	94,000	94,000
Caustic (50%) (gallons)	6,900	6,900	14,000	14,000
Hydrated lime (tons)	3,600	3,600	7,200	7,200
Soda ash (tons)	2,600	2,600	5,300	5,300
Electricity (megawatt hours)	9,700	10,000	19,000	20,000
Steam (million British thermal units)	14	14	14	14
Cooling water (million gallons)	200	200	400	400
Residual – softening and blowdown solids (dry tons solids)	15,000	15,000	30,000	30,000
Residual – crystallizer solids (dry tons solids)	3,300	3,300	6,700	6,700
Full time employee – operator	10	10	10	10
Full time employee – supervisor	1	1	1	1
Full time employee – chemical engineer	1	1	1	1
Full time employee – total	12	12	12	12

Table C-7
Summary of estimated annual O&M quantities

	300 gpm		600 gpm	
Cost Element	**2 x 60%**	**2 x 100%**	**2 x 60%**	**2 x 100%**
Major Chemicals				
Sulfuric acid (93%) (gallons)	47,000	47,000	94,000	94,000
Caustic (50%) (gallons)	6,900	6,900	14,000	14,000
Hydrated lime (tons)	3,600	3,600	7,200	7,200
Soda ash (tons)	2,600	2,600	5,300	5,300
Electricity (megawatt hours)	9,700	10,000	19,000	20,000
Steam (million British thermal units)	14	14	14	14
Cooling water (million gallons)	200	200	400	400
Residual – softening and blowdown solids (dry tons solids)	15,000	15,000	30,000	30,000
Residual – crystallizer solids (dry tons solids)	3,300	3,300	6,700	6,700
Full time employee – operator	10	10	10	10
Full time employee – supervisor	1	1	1	1
Full time employee – chemical engineer	1	1	1	1
Full time employee – total	12	12	12	12

Table C-7
Summary of estimated annual O&M quantities

	300 gpm		600 gpm	
Cost Element	**2 x 60%**	**2 x 100%**	**2 x 60%**	**2 x 100%**
Major Chemicals				
Sulfuric acid (93%) (gallons)	47,000	47,000	94,000	94,000
Caustic (50%) (gallons)	6,900	6,900	14,000	14,000
Hydrated lime (tons)	3,600	3,600	7,200	7,200
Soda ash (tons)	2,600	2,600	5,300	5,300
Electricity (megawatt hours)	9,700	10,000	19,000	20,000
Steam (million British thermal units)	14	14	14	14
Cooling water (million gallons)	200	200	400	400
Residual – softening and blowdown solids (dry tons solids)	15,000	15,000	30,000	30,000
Residual – crystallizer solids (dry tons solids)	3,300	3,300	6,700	6,700
Full time employee – operator	10	10	10	10
Full time employee – supervisor	1	1	1	1
Full time employee – chemical engineer	1	1	1	1
Full time employee – total	12	12	12	12

C.1.8.3 Annualized costs

Capital cost estimates (Table C-5) and O&M cost estimates (Table C-6) were used to calculate total annualized costs for the system. Capital costs were annualized assuming an equipment lifetime of 20 years and 7 percent interest rate. Annualized costs are presented in Table C-8.

Table C-8
Treatment annualized costs, in June 2018 dollars

	300 gpm	300 gpm	600 gpm	600 gpm
Cost Element	**2 x 60%**	**2 x 100%**	**2 x 60%**	**2 x 100%**
Capital costs ($M)	109	171	216	251
Annualized Capital costs ($M per year) [a]	10	16	20	24
Annual O&M costs ($M per year)	8	9	13	15
Total annualized costs ($M per year)	18	25	34	38

[a] Capital costs are annualized by assuming a lifetime of 20 years and 7 percent interest rate. Annualized costs shown are for Year 1.
$ = U.S. dollars
M = million
O&M = operations and maintenance

C.1.9 Industry cost extrapolation

Industry costs were estimated for the current industry. Assumptions used to develop the list of plants for industry extrapolation are presented in Appendix A.1.9. As described, EPRI used EPA's list of 70 plants with FGD flows [ERG, 2019] for the industry extrapolation.

C.1.9.1 Flow rate basis

EPA provided updated FGD purge flows for all plants in Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings – DCN SE07091 [ERG, 2019]. EPRI reviewed the flows reported by EPA and used best professional judgement to resolve flow changes from the 2009 ICR response. Then EPRI estimated a peak flow for each plant in one of four ways:

- If EPA's 2019 FGD purge flow matched the plant's reported typical purge flow (ICR response B5-2) or if it appeared that EPA made reasonable adjustments to the plant's reported typical purge flow based on units added/retired since the ICR response, then EPRI used EPA's assumed FGD purge flow. To determine peak flow, EPRI multiplied EPA's FGD purge flow by a peaking factor of 1.5.
- For two plants, there was insufficient information to understand why EPA had reduced the plant's reported purge flow since the ICR response. For these plants EPRI used the plant's original ICR response for FGD purge flow (ICR response B5-2) and then applied a peaking factor of 1.5 to determine the plant's peak flow.
- EPRI used the plant's reported peak wastewater treatment system (WWTS) design flow (ICR response D5-3), where it was more suitable in EPRI's best professional judgment. No peaking factor was applied where EPRI used the plant's reported peak WWTS design flow.
- For two plants, EPRI used a peak flow basis derived from the original FGD WWTS design flow (ICR response D5-3), which was adjusted based on units added/retired since the ICR response.

The peak flow rate was used to size all equipment to determine the capital cost of the system.

EPRI estimated an average flow for each plant in one of three ways:

- If EPA's 2019 FGD purge flow matched the plant's reported typical purge flow (ICR response B5-2) or if it appeared that EPA made reasonable adjustments to the plant's reported typical purge flow based on units added/retired since the ICR response, then EPRI used EPA's assumed FGD purge flow.
- For two plants, EPRI developed an assumed average flow by dividing the assumed peak flow by a peaking factor of 1.5.
- For one plant, EPRI used the original ICR response for FGD purge flow (ICR response B5- 2), where there was insufficient information to understand why EPA had reduced the plant's reported purge flow since the ICR response.

The average flow rate was used to calculate the operations and maintenance (O&M) cost of operating the treatment system.

C.1.9.2 Solids loading

The TSS assumptions for each power plant used to develop the industry cost extrapolation are presented in Appendix A. The TSS concentration of 13,315 mg/L assumed in the case study evaluation was adjusted for each plant's estimated solids loading to size solids dewatering equipment and estimate solids disposal costs.

C.1.9.3 Capacity factor basis

EPRI used the net generation rates from 2017 to estimate a capacity factor for each plant. The site-specific capacity factor was used in place of the 0.51 capacity factor (which was used in EPRI's case study cost estimates). Further, the site-specific capacity factor was used to predict the equipment redundancy assumptions for each plant, as discussed in Section C.1.9.4.

C.1.9.4 CS + VCE/CRX capital costs

EPRI calculated estimated CS + VCE/CRX capital costs for each of the 70 plants based on the conceptual case studies developed for two different flows (300 and 600 gpm), two different redundancies (2x60% and 2x100%), and two different vendor quotations (Vendor A and Vendor B). The costs for the evaporator/crystallizer vendor package and support equipment were scaled from the conceptual design cases (Table C-5) based on each plant's design flow rate basis. The following methodology was used to develop capital costs for each of the 70 plants:

- EPRI used a site-specific capacity factor for each of the 70 plants.
- The total cost for the industry was estimated assuming that industry plants with a reported capacity factor greater than 0.60 (26 percent of industry plants) would install a 2 x 100 percent redundancy CS + VCE/CRX system. The remaining plants with reported lower capacity factors (74 percent of industry plants) would install a 2 x 60 percent redundancy CS+VCE/CRX system.
- EPRI used the 300 gpm case study costs for estimating the costs for plants with design flows less than 600 gpm. EPRI used the 600 gpm case study costs for estimating the costs for plants with design flows greater than 600 gpm.
- For plants with design flows less than 600 gpm, EPRI assumed an average of Vendor A and Vendor B costs for only the 2 x 60% redundancy case. Because of limitations on information available from Vendor A, estimated costs for the other three design cases were developed using only costs provided by Vendor B.

After scaling equipment costs, the following cost adjustments were made:

- Dewatering equipment costs were adjusted from the conceptual design case of 13,315 mg/L feed TSS based on each plant's actual solids loading.
- Support equipment costs were adjusted based on the assumed treatment in place for each plant:
    - If a facility had an existing chemical precipitation plant (consisting of equalization, clarifiers, and dewatering processes), a capital cost credit was

applied, assuming this infrastructure could be repurposed. Twenty-four plants had some type of credit applied.
    - If a facility only had an existing equalization system and dewatering process, a lesser capital cost credit was applied, assuming the equalization tanks and dewatering system could also be reused. Thirteen plants had this credit applied.
- Three plants had an existing thermal evaporation system; therefore, EPRI assigned no cost for additional capital expenditure.

C.1.9.5 CS + VCE/CRX O&M costs

EPRI calculated estimated O&M costs for each of the 70 plants by scaling from the conceptual design cases (Table C-6) based on each plant's design flow rate and solids loading basis. After scaling O&M costs, the following cost adjustments were made:

- If a facility had an existing pond, it was assumed that the pond would be replaced by a treatment system similar to that shown in Figure A-1. A total of 27 plants had FGD ponds, and an O&M credit was applied for ceasing operation of the pond. The cost of pond closure was not included in this estimate.
- Six facilities had existing biological treatment systems for FGD wastewater. Similarly, an O&M credit was applied for ceasing operation of the biological treatment system.
- Thirty-eight facilities had some type of existing chemical precipitation treatment in place. Similarly, an O&M credit was applied for the existing chemical precipitation operating costs incurred by these facilities.
- Three plants had an existing thermal evaporation system; therefore, EPRI assigned no cost for additional O&M expenditures.

C.1.9.6 Landfill leachate costs

Plants installing a CS + VCE/CRX system would generate additional solid waste (softener solids and salt cake solids) that would require disposal in a lined landfill. Further, deposition of this waste in the landfill would likely lead to generation of additional landfill leachate. EPA's unit costs for landfill disposal [EPA, 2013] appear to include costs for landfill development/expansion and leachate collection, but do not include the costs for additional landfill leachate treatment. Therefore, EPRI has estimated the additional landfill leachate volume that may be generated as a result of installing the CS + VCE/CRX system and then estimated capital and O&M costs for landfill leachate treatment system improvements. The following assumptions were used in development of costs for leachate treatment:

- The quantity of landfill leachate generated will be highly site-specific and will be based on the site's landfill operations, leachate collection system, and other factors. For this analysis, EPRI has assumed that additional leachate generation per plant would be an average of 20 gpm. EPRI has developed this design flow assumption based on case study data shared at the 2019 World of Coal Ash Conference [Ruhl, 2019]. EPRI assumed installation of a new equalization pond would be required given the small treatment system design flow basis.

- Similarly, the quality of landfill leachate is unknown, highly variable and would require sitespecific analysis. For the purposes of cost estimation, EPRI has assumed that the composition of leachate generated would be similar to existing site leachate. Chemical precipitation treatment systems were the basis for cost analysis. C-20
- 75 percent of industry plants will use onsite landfills and 25 percent of industry plants will use offsite landfills.
- EPRI used professional best judgment in assuming that 50 percent of sites may require improvements for landfill leachate treatment, while the rest of the industry was assumed to have adequate treatment in place already. Therefore, 50 percent of plants would incur additional capital and O&M costs related to leachate treatment improvements and the other 50 percent of plants would incur no additional cost for leachate treatment.
- Half of the plants requiring onsite treatment improvements would be able to co-treat the additional landfill leachate in their FGD wastewater treatment system, leading to an increase in the size of the CS+VCE/CRX treatment system. EPRI estimated the incremental capital and O&M cost for installing a CS + VCE/CRX treatment system with a higher design flowrate using the same cost methodology presented in this appendix.
- The remaining plants requiring onsite leachate treatment would require a new stand-alone chemical precipitation (CP) treatment system. EPRI estimated the capital and O&M cost for CP treatment based on previous work evaluating landfill leachate treatment options and costs [EPRI, 2018].
- Costs for plants requiring offsite leachate treatment system improvements were also based on stand-alone CP treatment and EPRI's previous work [EPRI, 2018].
- Costs include installation of a 1,000,000-gallon leachate equalization pond for those sites that EPRI assumed would require landfill leachate treatment system improvements.

Table C-9 summarizes landfill leachate treatment costs to the current industry.

Table C-9
Leachate treatment costs to current industry for FGD wastewater, in June 2018 dollars [a]

Treatment Option	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Annualized Cost [a] ($M per year)
Landfill Leachate System [b]	$279	$14	$40

[a] Annualized cost based on a 20-year equipment life and 7% interest rate.
[b] Landfill leachate costs were estimated assuming that half of the industry would require leachate treatment system upgrades
$ = U.S. dollars
M = million

19 <u>BATW – General</u>

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 2

Comment Excerpt:

2. EPA's proposed changes for regulating Bottom Ash Transport Water (BATW) are warranted.

The ELGs are established by EPA regulation for categories of industrial dischargers and are based on the degree of control that can be achieved by performance of well-designed and well-operated best available technologies[1]. The 2019 proposal clarifies some critical issues regarding BATW from the 2015 Rule.

[1]Fed. Reg. Vol 84, p. 64623

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 3

Comment Excerpt:

A. EPA correctly re-establishes the Best Available Technology (BAT) for BATW from the 2015 Rule.

For establishment of BAT within the ELGs, the CWA requires EPA to consider not only the technological availability of BAT, but also the economic achievability of such technology[2]. BAT is intended to reflect the highest performance of a technology in an industry, but in such an economical way that is effective and achievable. Therefore, a technology may have the highest performance, but if it is not economically achievable across the industry, it should not be considered as BAT. In the 2019 proposal, EPA appropriately proposes to base the BATW BAT limits on the use of dry handling or high recycle rate systems instead of the closed loop systems identified in the 2015 Rule. In the 2019 proposal, EPA writes "In light of the foregoing process changes (and associated engineering challenges) that facilities would need to make to implement a true zero discharge BA transport water limitation . . . the EPA proposes to base the BA transport water BAT limitations on the use of dry handling or high recycle rate systems rather than dry handling or closed-loop systems.[3]" Therefore, as stated by the EPA, The change of BAT model technology is supported by operational challenges that have been identified with closed-loop systems, which causes them to not be the best available technology and supports the finding that a high recycle rate system is more achievable. Additionally, the cost associated with completely closing a "closed-loop" system has been demonstrated by the industry to be high compared to minimal amount of pollutant loading that would be discharged to the environment[4].

[2] Fed. Reg. Vol 84, p. 64624
[3] Fed. Reg. Vol 84, p. 64635
[4] Comments of UWAG in EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 1

Comment Excerpt:

Specifically, EPA should:

- Finalize the revised best available technology (BAT) limits for BA TW while including essential compliance flexibilities like rolling average provisions, blowdown allowances and an allowance for additional discharges where necessary to account for large scale natural disasters that overwhelm current BATW systems because of heavy and prolonged precipitation. EPA also should allow permit writers to extend the applicability dates for BATW compliance beyond December 31, 2023;

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 7

Comment Excerpt:

EPA also should allow permit writers to extend the applicability dates for BATW compliance beyond December 31, 2023 given the time-consuming and resource-intensive process that permit writers must engage in once EPA finalizes the rule.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 6

Comment Excerpt:

1.1 Introduction

In its November 22, 2019 proposed revisions to the 2015 ELG Rule,[2] EPA has proposed the following changes to the Best Available Technology (BAT)[3] standard for the disposal of bottom ash transport water (BATW).

"For bottom ash transport water, there are two sets of proposed BAT limitations. The first set of BAT limitations is a numeric effluent limitation on TSS in the discharge of these wastewaters. The second set of BAT limitations is a not-too-exceed 10 percent volumetric purge limitation."[4]

I will be addressing the second of the two proposed changes, namely the "not-to-exceed 10 percent volumetric purge limitation." EPA has also referred to this as the "high recycle rate" system in contrast to the 2015 Rule's requirement for zero discharge of BATW to receiving waters, with limited exceptions for disposal as a plant's flue gas desulfurization (FGD) makeup water.

It is my opinion, based on a careful review of all of the BATW-related documents in the docket for the rule that are publicly available, and supported by the technical discussion in this report, that EPA's 10% purge allowance is unnecessary. As EPA itself recognizes, almost three quarters of the coal-fired power plants in the U.S. already have some form of closed-loop BATW or dry bottom ash handling systems in place.[5] Table 3-3 from the proposed rule's Technical Development Document (TDD), reproduced below, shows the number of plants and generating units with various types of bottom ash handling systems.

Table 3-3. Bottom Ash Handling Systems for Coal-Fired Generating Units[6]

Bottom Ash Handling System	Number of Plants	Number of Generating Units	Nameplate Capacity (MW)
Wet Sluicing System with Limited or No Recycle	62	126	54,800
Wet Sluicing Closed-Loop/High Recycle Rate System	56	140	75,000
Dry Bottom Ash Handling System	173	284	101,000
Total	**284**	**550**	**230,000**

Only a minority of operating plants (roughly 90 or so) have not installed such systems prior to this proposed rule change.[7] EPA's proposal would reward these laggard plants and their operators with additional "flexibility" and compliance time. This is plainly unfair to the majority of plants and operators who have already installed systems to achieve compliance with the 2015 Rule. To the extent that plants that have wet handling of bottom ash, have installed BATW closed loop systems, and are faced with dealing with purge water from these systems, the 2015 Rule provides sufficient flexibility (i.e., disposal of such purge waters as make-up water to flue gas desulfurization (FGD) units if present (which many such plants have). For others, fairly simple engineering changes (use of non-leaking components such as seal-less pumps and/or storage followed by reuse in the BATW system) can avoid the discharge of such purge waters.

Based on my review of the record, it is my opinion that the current (i.e., 2015 ELG Rule) zero discharge limitation for BATW is feasible and there is no need to provide the 10% system volume purge on a 30-day rolling average basis which EPA has proposed.

[2] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Proposed Rule, 84 Fed. Reg. 64,620 (Nov. 22, 2019) (EPA-HQ-OW-2009-0819-7106).
[3] It is my understanding that the BAT standard should reflect what is being done at the best-performing plants (and not at the average and certainly not at the less-than-average plants) including a consideration of both long-term and short-term performance.
[4] 84 Fed. Reg. at 64,622.
[5] "The EPA estimates that more than 75 percent of generating units operate either dry, closed-loop recycle, or high recycle rate bottom ash handling systems." Supplemental Technical Development Document ("TDD") for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, at 3-8 (Nov. 2019) (EPA-HQ-OW-2009-0819-8211).
[6] TDD at 3-9.
[7] See Table 5-10 of the TDD at 5-60, which cites to 94 plants. I note that Table 3-1 in the preamble states that 138 units at 61 plants have, since August 2014, installed or converted to dry, closed-loop recycle, or high recycle bottom ash handling systems. Thus, these plants have taken at least some actions under the 2015 rule. In Section 6.2 of the TDD EPA states that it "…identified 71 coal-fired power plants that operate wet bottom ash handling systems and discharge the bottom ash transport water to surface water or to a POTW." TDD at 6-11.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 7

Comment Excerpt:

1.2 BATW Contains Numerous Toxic Contaminants

Unsurprisingly, BATW is not benign water. Water that comes into contact with bottom ash in a coal-fired power plant becomes contaminated. EPA's own prior analysis of the composition of BATW supplemented by at least two additional analyses[8] from operating companies proves this beyond any doubt.[9] Thus, directly allowing its discharge will increase the loading of contaminants to receiving waters as confirmed by EPA's own loading analyses[10] accompanying this proposed rule. The list of contaminants in BATW as provided in EPA's TDD, Table 6-2 is shown below.

Table 6-2. Pollutants Present in Bottom Ash Transport Water Effluent

Pollutant	Unit	Average Concentration
Conventional Pollutants		
Chemical Oxygen Demand (COD)	µg/L	20,800
Total Suspended Solids (TSS)	µg/L	13,400
Priority Pollutants		
Antimony	µg/L	17.3
Arsenic	µg/L	9.32
Cadmium	µg/L	0.721
Chromium	µg/L	5.08
Copper	µg/L	3.95
Lead	µg/L	10.4
Mercury	µg/L	0.102
Nickel	µg/L	17.5
Selenium	µg/L	12.3
Thallium	µg/L	1.13
Zinc	µg/L	33.8
Nonconventional Pollutants [a]		
Aluminum	µg/L	854
Barium	µg/L	106
Boron	µg/L	5,310

Table 6-2. Pollutants Present in Bottom Ash Transport Water Effluent

Pollutant	Unit	Average Concentration
Bromide	µg/L	5,100
Calcium	µg/L	154,00
Chloride	µg/L	321,000
Cobalt	µg/L	9.19
Iron	µg/L	676
Magnesium	µg/L	55,700
Manganese	µg/L	153
Molybdenum	µg/L	28.3
Nitrate-Nitrite (as N)	µg/L	1,670
Phosphorus	µg/L	222
Potassium	µg/L	19,600
Silica	µg/L	8,160
Sodium	µg/L	119,000
Strontium	µg/L	1,430
Sulfate	µg/L	504,000
Sulfite	µg/L	3,920
Titanium	µg/L	35.9
Total Dissolved Solids (TDS)	µg/L	1,290,000
Total Kjeldahl Nitrogen (TKN)	µg/L	968
Vanadium	µg/L	10.1

Source: U.S. EPA, 2015; ERG, 2019e.

Note: Loadings are rounded to three significant figures. The EPA did not generate an average pollutant concentration for pollutants where all sample results are less than the quantitation limit.

a – The EPA identified ammonia (as N) as a pollutant present in bottom ash transport water; however, the EPA excluded this parameter from the calculation of pollutant loadings to avoid double-counting of nitrogen compounds.

However, while BATW as generated is contaminated, it can be treated to make it suitable for reuse not only for its intended purpose – i.e., continued removal of bottom ash from below the boiler – but also in other parts of a coal-fired power plant such as any FGDs in place[11] or even as make-up water for the steam cycle itself.

[8] See TDD 6-11 n.44. The only two plants that chose to provide additional BATW data to the EPA per its voluntary request are the CPS J.T. Deely and the TEC Big Bend power plants.
[9] TDD 6-11 – 6-13.
[10] See generally TDD Section 6.
[11] The vast majority of operating U.S. coal-fired power plants have either wet or dry FGD systems. And, even for the subset of plants which is the focus of EPA's BATW relief via the 10% purge allowance, most such plants have FGDs with wastewater treatment systems. See ERG Memorandum Re: Flue Gas Desulfurization Wastewater Treatment in Place at Steam Electric Power Plants – DCN SE07092 (July 8, 2019) (EPA-HQ-OW-2009-0819-7807).

Commenter Name: Tara A. Rocque, Washington University Interdisciplinary Environmental Clinic
Commenter Affiliation: Labadie Environmental Organization ("LEO"), Missouri Chapter of the Sierra Club
Document Control Number: EPA-HQ-OW-2009-0819-8303-A1
Comment Excerpt Number: 2

Comment Excerpt:

The 2015 ELG rule established for the first time best available technology economically achievable (BAT) for bottom ash and fly ash transport water.[2] EPA determined that BAT for bottom ash and fly ash transport water is no-discharge.[3] Thus, utilities must cease discharging bottom ash and fly ash transport water. Bottom ash and fly ash transport water are frequently comingled along with other waste streams such as coal pile runoff. Establishing no-discharge as BAT would significantly reduce these waste streams discharges since CCR ponds are designed to discharge tens of millions of gallons of wastewater per day. This wastewater contains dangerous metals such as selenium, arsenic and boron as well as bromide which poses a significant risk to drinking water treatment systems. EPA also projected that without the 2015 ELG rule, steam electric power plant discharges would comprise 30 percent of all toxic pollutants from industrial discharges.[4] In fact, EPA stated that "recent studies indicate that steam electric power plant discharges can adversely affect surface waters used as drinking water supplies."[5] Given the magnitude of toxic pollutants and threat to drinking water sources, EPA appropriately determined no-discharge to be BAT for bottom ash and fly ash wastewater.

Unfortunately, EPA has proposed to significantly weaken the 2015 ELG rule by allowing utilities to continue to discharge bottom ash transport water.[6] EPA proposes to allow up to 10% of the system volume per day on a 30-day rolling average to account for "challenges" that utilities allegedly face in meeting the 2015 ELG Rule requirements for bottom ash transport water.[7] This rollback could significantly increase bottom ash transport water in Missouri.

[2] 40 CFR 423.13.
[3] 40 CFR 423.13(h)(1)(i) states "[e]xcept for those discharges to which paragraph ((h)(2) of this section applies, or when the fly ash transport water is used in the FGD scrubber, there shall be no discharge of pollutants in fly ash transport water" and (k)(1)(i) states "[e]xcept for those discharges to which paragraph (k)(2) of this section applies, or when the bottom ash transport water is used in the FGD scrubber, there shall be not discharge of pollutants in bottom ash transport water."
[4] 80 FR 67840, footnote 2.
[5] 80 FR 67840.
[6] 84 FR 64635.
[7] 84 FR 64635.

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 13

Comment Excerpt:

IV. EPA must clarify in the regulatory text that quench bath water is low volume waste, not BA transport water.

Quench bath water from under-boiler mechanical drag systems (MDS) is identified as a component of a dry bottom ash handling system, which does not generate BA transport water.[5] EPA also acknowledged quench bath water as part of remote mechanical drag systems (rMDS), which do generate bottom ash transport water. The distinguishing feature between MDS and rMDS is the ash transport mechanism – in an MDS, the drag chain transports bottom ash out of the boiler for dry handling and disposal; in an rMDS, *water* transports bottom ash to the remote drag chain for handling and dry disposal. The purpose of an MDS quench bath is to reduce the temperature of bottom ash as it exits the boiler to allow for safe handling.

EPA recognized these distinctions and characterized MDS quench bath water as low volume waste in the proposed rule's supplemental technical development document.[6] EPA should go one step further and clarify in the final rule that MDS quench bath water is low volume waste, not bottom ash transport water. A mechanical drag system need not operate as a closed-loop system because the quench bath water is not BA transport water. Such clarity is needed for permitting authorities to develop appropriate permit limits.

[5] Id. at 64,628
[6] Supplemental Technical Development Documentation for the Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 4-9. EPA-821-R-19-009. November 2019.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 61

Comment Excerpt:

8.5 **Bottom ash pollutant removals**

EPRI compared bottom ash water quality from our data with EPA's. It appears that EPA's pollutant loading estimate, expressed as pounds per gallon, is greater than EPRI's estimate as listed in Table 8-4. EPRI believes this is an over estimation of the pollutant loading.

It appears that EPA does not net source water from their BATW characterization and that only ash pond effluent data were used. Because pollutant loading is a measure of *net* addition of pollutants, EPRI subtracts source water from the BATW. As shown in Table 8-4, EPRI estimates that the source water contribution of pollutants makes up about 79 percent of BATW on a pound per unit gallon basis.

Table 8-4
Pollution reduction estimates by EPRI and EPA

	EPA pounds/million gallon	EPRI – Subtracting out Source Water pounds/million gallon [1]	EPRI – Not Subtracting out Source Water pounds/million gallon [1]
Bottom ash—concentration characterization	10,900 [2]	607	2,900

[1] EPRI's estimate is based on single pass BATW concentrations as described in Appendix G
[2] EPA's value estimated by adding the TSS and TDS values as listed in ERG's Bottom Ash Transportation Water Pollutant Loadings Model Effluent Concentration 10 - Average Pond Concentrations Query [ERG, 2019b] and converting to pounds per gallon

Our pollution reduction estimating approach is documented in Appendix G.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 70

Comment Excerpt:

H —APPENDIX: BOTTOM ASH HANDLING POLLUTANT LOADING REDUCTION METHODOLOGY

H.1 EPRI's calculations of bottom ash transport water treatment pollutant reductions

In this appendix, pollutant reductions are expressed in toxic-weighted pounds-equivalent (TWPE) and in pounds. The overall cost-effectiveness of pollutant reduction reflects the total annualized cost per TWPE removed and pounds removed per year.

H.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the reduction of pollutants of eliminating discharge of bottom ash transport water from the steam electric industry based on EPA's industry profile [ERG, 2019]. This appendix describes the method for calculation of pollutant reductions, the assumptions associated with the calculations, and the estimated incremental pollutant reductions of changing from single-pass bottom ash transport water to high-rate recycle systems with a 10% allowable purge in the steam electric industry.

Table H-1 summarizes the pollutant reductions of bottom ash treatment to the industry. The calculations of these pollutant reductions are provided below.

Table H-1
Annualized industry* reduction of pollutants from single-pass bottom ash handling (high-rate recycle with a 10% allowable purge)

EPRI (TWPE per year)	EPRI (pounds per year)
63,117	23,492,710

MW = megawatt
TWPE = toxic-weighted pounds-equivalent
*To be consistent with EPA, this analysis includes only units greater than 50 MW.

H.1.2 Calculation methodology

H.1.2.1 Pollutant reduction calculation overview

For this analysis, the pollutant reductions were defined as the incremental amount of pollutants removed from bottom ash transport water. For each pollutant, the net bottom ash discharge was calculated by subtracting out the source water concentration from the bottom ash transport water concentration. The incremental pollutant reductions of high-rate recycle system with a 10% allowable purge were calculated as toxic-weighted pound equivalents (TWPE) and pounds. TWPE factors are used by EPA to express the relative toxicity of pollutants. Use of TWPE provides a relative measure comparing the potential toxicity of different pollutants. EPRI used the average net bottom ash discharge from its dataset, estimated bottom ash transport water flow rate, and toxic weighting factors (TWF) published by EPA to calculate total TWPE per year removed. The TWFs used in this evaluation were published in *Technical Support Document for the Annual Review of Existing Effluent Guidelines and Identification of Potential New Point Source Categories* [EPA, 2009] with updated factors for arsenic, cadmium, copper, manganese, mercury, thallium, and vanadium as published in *Review of Toxic Weighting Factors in Support of the final Steam Electric Effluent Limitations Guidelines and Standards* [ERG, 2015].

H.1.2.2 Defined Terms

Terms used in this evaluation include:

Source water – Water that will be used to transport the bottom ash (before it is in contact with bottom ash).

Bottom ash transport water – Water used to transport bottom ash (during contact with bottom ash).

Incremental pollutant reduction – The incremental amount removed is estimated by subtracting out the source water pollutants loading from bottom ash transport water pollutants loading.

H.1.2.3 Summary of data used for the pollutant reductions evaluation

As part of the effort to estimate the pollutant reductions of going from single-pass to a 10% allowable purge, EPRI used two sets of water quality data. For the 10 % allowable purge loading, EPRI used the water quality data as described in EPRI's *Guidance Document for Management of Closed-Loop Bottom Ash Handling Water in Compliance with the 2015 Effluent Limitations Guidelines* [EPRI, 2016].

For the single-pass water quality data, EPRI used bottom ash transport water and source water data from the voluntary submission of data by 20 power plants to the Utility Water Act Group (UWAG), and a set of data from 5 power plants representing samples that EPRI had previously collected for the PISCES project in the 1990s. In addition, 2014 sample data that UWAG had obtained from 6 plants (Kammer, Kyger Creek, Tanners Creek, Daniel, Stanton, and Ratts) were included from the following source:

- Letter to EPA, UWAG Additional Bottom Ash Transport Water Data, EPA-HQ-OW-2009- 0819-5672, DCN SE05597A1

The samples were analyzed for metals[2], nutrients, and major ions. However, not all samples included all analytes.

When data were reported below the method detection limit (MDL) or were not detected, EPRI used one-half the method detection limit to calculate pollutant reduction.

In some cases, the concentration of certain pollutants in the source water was higher than the concentration in the bottom ash transport water. For example, the aluminum concentration for plant #7 decreased from 180 µg/L in source water to 85 µg/L in bottom ash settled water. For the purposes of this estimate, EPRI assumed zero removal rather than "negative removals."

The data used to represent bottom ash transport water appears to not include bromide. To account for bromide in the bottom ash transport water, EPA's value was used. EPRI conservatively assumed there was zero bromide in the source water.

H.1.3 Reduction of pollutants calculation

H.1.3.1 Water flow rate

EPRI calculated the industry single-pass flowrate as 48 billion gallons per year and the 10% purge flow rate as 3 billion gallons per year. This is the same flow-rate that EPRI used in the bottom ash transport water cost calculations (Appendix F).

H.1.3.2 Water quality characterization

The pollutant concentrations of source water and bottom ash transport water from each power plant to characterize the single pass pollutant loading are summarized in Table H-3 (at end of appendix). For each pollutant, the net bottom ash discharge (that is, incremental pollutant reduction of single-pass and for the 10% purge respective to the water quality dataset) was calculated by subtracting out the source water concentration from bottom ash transport water concentration. The mean and median concentration of each parameter was calculated.

H.1.3.3 Pollutant reductions

EPRI estimated pollutant reduction (TWPE and pounds per year removed) by multiplying the mean and median concentration of each parameter by the assumed flow rate for the industry (48 billion gallons for the single-pass and 3 billion gallons for the 10% purge), and 8.36 conversion factor (1,000,000,000 gallons per billion gallons multiplied by 3.79 liters per gallon divided by 453.6 grams per pound multiplied by 1x10-6 grams to microgram) to convert flow rate* concentration to mass flow rate. The pollutant reductions are summarized at the end of Table H-4 (at end of appendix). Estimates for both mean and median are provided. The pounds per year total represents the sum of all analyte data excluding TSS and TDS to avoid double counting. The average (mean) single purge loadings were subtracted by the median 10 % purge to calculate the pollutant reduction estimates. Based on the 10% purge water quality dataset the median more appropriately characterizes the dataset compared to the mean. The pollutant reduction estimates in TWPE and pounds per year removed as well as unit pounds per million gallons are summarized in Table H-2. These are the values EPRI is presenting in our comments.

Table H-2
EPRI estimate of pollutant reduction from bottom ash handling (single-pass closed looped with a 10% allowable purge)

Category	Pollutant Reduction (TWPE per year)	Pollutant Reduction (pounds per year)	Unit Pollutant Reduction (pounds per million gallons)
All Plants (subtracting out source water) [1]	63,117	23,492,710	607
All Plants (Bottom ash water, not subtracting out source water)	150,955	128,623,144	2,914

MW = megawatt
TWPE = toxic-weighted pounds-equivalent BG = billion gallons
[1] To account for bromide in the single-pass loadings EPA's average concentration for bromide was included. The source water was assumed to have no bromide.
* To be consistent with EPA, this analysis includes only units greater than 50 MW.

H.1.3.4 Pollutant reduction comparison of the current industry practices and Option 2.

EPRI's analysis confirms that Option 2 is highly effective at reducing BATW TWPEs. EPA's proposed Option 2 includes dry handling or high recycle rates for most units, surface impoundments for units retiring by 2028 and surface impoundments and BMP for low utilization units.

EPRI calculated BATW loadings assuming current industry practices and Option 2 BATW loadings and TWPEs as follows:

Flow in Gallons Per Day (either Ash Sluice flow or 10% Purge EPA Estimated Flow) x Online Capacity Factor x 365 Days Per Year x Pollutant Factor.

The Pollutant Factors for the ash sluice flow were calculated by EPRI as a constant of 1.51E-06 TWPE per gallon and 6.07E-04 pounds pollutants per gallon. This was the average based on bottom ash sluice water subtracted by source water. Plant data included in this average are: Daniel, Mississippi, Kammer Plant, Kyger Creek Station, PISCES Site A, PISCES Site B, PISCES Site C, PISCES Site D, PISCES Site E, Frank E. Ratts Generating Station, Stanton, Great River Energy, Tanners Creek, Indiana Michigan Power, UWAG Plant #1, UWAG Plant #2, UWAG Plant #3, UWAG Plant #4, UWAG Plant #5, UWAG Plant #6, UWAG Plant #7, UWAG Plant #9, UWAG Plant #10, UWAG Plant #11, UWAG Plant #12, UWAG Plant #13, UWAG Plant #14, UWAG Plant #15, UWAG Plant #16, UWAG Plant #17, UWAG Plant #18, UWAG Plant #19, UWAG Plant #20, UWAG Plant #21.

The Pollutant Factors for the 10% Purge were calculated by EPRI as 3.06E-06 TWPE per gallon or 1.84E-03 pounds per gallon. This value is based on the median concentration data from a limited set of partially closed-loop systems' bottom ash transport water after subtracting out the service water contributions. Data were pulled from Appendix A of *Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges - 2019 Update* [EPRI, 2019].

EPRI calculates the current industry practice loading as 29,000,000 pounds per year or 72,000 TWPE per year. EPRI calculates Option 2 loading as 3,540,000 or 7,800 TWPE per year.

Based on its calculations, EPRI shows that Option 2 decreases TWPE due to BATW by about 89% over the Current Industry Practice case. Similarly, loadings decrease by 88%.

Table H-3
Bottom ash water quality characterization data

		Daniel, Mississippi		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.0646691216	872	2,340	1,468
Antimony	0.01225	0.611	0.606	0
Arsenic	3.469133333	4.84	5.97	1.13
Barium	0.001990757	185	341	156
Beryllium	1.056603774	0.050	0.099	0.049
Boron	0.008341667	1,930	1,850	0
Cadmium	22.7584	0.013	0.076	0.063
Calcium	0.000028	22,200	27,000	4,800
Chromium	0.0750696709	1.79	4.08	2.29
Cobalt	0.114285714	0.142	0.299	0.157
Copper	0.6234822222	2.29	26.0	23.7
Iron	0.0056	166	574	408
Lead	2.24	0.238	0.899	0.661
Magnesium	0.000865533	3,000	3,020	20
Manganese	0.1026666667	3.10	8.32	5.22
Mercury	110.6327273	1.37E-03	1.89E-03	5.20E-04
Molybdenum	0.201430849	47	41	0.00
Nickel	0.108914308	0.460	1.42	0.960
Selenium	1.121344	1.39	1.34	0
Silver	16.47072824	0.028	0.019	0
Sodium	0.00000549	45,200	42,200	0
Thallium	2.854901961	0.0255	0.0255	0
Tin	0.301075269	0.05	0.05	0
Titanium	0.029319372	16.2	97.9	81.7
Vanadium	0.28	18.9	29.0	10.1
Zinc	0.046886	2.40	2.70	0.30
Chloride	0.0000243	14,400	13,600	0
Sulfate	0.0000056	48,000	52,000	4,000
Nitrate/Nitrite	0.0032	100	100	0
Total Phosphorus	0	213	249	36
Ammonia-N	0.00111	25	25	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0	200	230	30
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0	223,000	243,000	20,000
Total Suspended Solids	0	4,000	28,000	24,000
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228	340	290	0
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		Daniel, Mississippi		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		Kammer Plant		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	282	1,770	1,488
Antimony	0.01225	0.0285	0.0285	0
Arsenic	3.469133333	0.83	0.81	0
Barium	0.001990757	40.5	61.0	20.5
Beryllium	1.058603774	0.019	0.168	0.149
Boron	0.008341667	26.6	34.1	7.5
Cadmium	22.7584	0.042	0.042	0
Calcium	0.000028	28,900	29,400	500
Chromium	0.075606709	0.34	4.20	3.86
Cobalt	0.114285714	1.35	1.47	0.12
Copper	0.623482222	1.29	1.84	0.55
Iron	0.0056	589	2,140	1,551
Lead	2.24	0.888	0.812	0
Magnesium	0.000865533	7,560	7,880	320
Manganese	0.102666667	147	115	0
Mercury	110.0127273	4.01E-03	5.74E-03	1.73E-03
Molybdenum	0.201438849	1.12	1.18	0.06
Nickel	0.108914308	3.74	5.55	1.81
Selenium	1.121544	0.125	0.125	0
Silver	16.47072824	0.010	0.010	0
Sodium	0.00000549	23,100	23,900	800
Thallium	2.854901961	0.0085	0.0370	0.0285
Tin	0.301075269	0.15	0.15	0
Titanium	0.029319372	4.19	83.1	78.9
Vanadium	0.28	0.28	4.05	3.78
Zinc	0.046886	8.90	9.20	0.30
Chloride	0.0000243	35,200	34,600	0
Sulfate	0.0000056	55,000	58,400	3,400
Nitrate/Nitrite	0.0032	840	860	20
Total Phosphorus	0	30	60	30
Ammonia-N	0.00111	180	150	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0	400	530	130
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0	193,000	195,000	2,000
Total Suspended Solids	0	16,000	21,000	5,000
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228	1,280	1,390	110
Oil and Grease	0			

		Kammer Plant		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		Kyger Creek Station		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	6,470	6,850	380
Antimony	0.01225	0.096	0.114	0.018
Arsenic	3.469333333	1.66	8.91	7.25
Barium	0.001990737	81.5	70.7	0
Beryllium	1.056603774	0.276	0.494	0.218
Boron	0.008341667	34.4	79.2	44.8
Cadmium	22.7584	0.088	0.126	0.038
Calcium	0.000028	26,800	27,500	700
Chromium	0.075696709	5.46	13.2	7.74
Cobalt	0.114285714	2.31	3.90	1.59
Copper	0.623482222	4.80	6.18	1.38
Iron	0.0056	4,270	8,240	3,970
Lead	2.24	3.13	3.37	0.24
Magnesium	0.000865533	7,860	7,410	0
Manganese	0.102666667	174	114	0
Mercury	110.0327273	8.99E-03	6.55E-03	0.00E+00
Molybdenum	0.201430049	0.81	3.12	2.31
Nickel	0.108914308	6.54	14.6	8.06
Selenium	1.121344	0.125	0.860	0.735
Silver	16.47872624	0.022	0.022	0
Sodium	0.00000549	18,600	19,500	900
Thallium	2.854901961	0.06	0.50	0.44
Tin	0.300075269	0.51	0.34	0
Titanium	0.029319372	77	243	166
Vanadium	0.28	8.61	12.0	3.39
Zinc	0.046906	20.1	14.8	0
Chloride	0.0000243	28,000	27,800	0
Sulfate	0.0000056	46,200	69,000	22,800
Nitrate/Nitrite	0.0032	830	800	0
Total Phosphorus	0	40	70	30
Ammonia-N	0.00111	120	70	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0	400	620	220
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.800446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0	205,000	191,000	0
Total Suspended Solids	0	79,000	94,000	15,000
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228	1,230	1,420	190
Oil and Grease	0			

		Kyger Creek Station		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		PISCES Site A		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	267	2,697	2,430
Antimony	0.01225	2.10	3.62	1.53
Arsenic	3.469333333	0.94	7.42	6.47
Barium	0.001990757	18.4	82.3	63.9
Beryllium	1.056603774	0.013	0.477	0.464
Boron	0.008341667	80	120	40
Cadmium	22.7584	0.35	0.32	0
Calcium	0.000028	2,865	4,902	2,037
Chromium	0.075696709	0.83	7.10	6.27
Cobalt	0.114285714			
Copper	0.623482222	3.56	13.25	9.68
Iron	0.0056	438	1,854	1,415
Lead	2.24	1.01	4.56	3.55
Magnesium	0.000865533	1,299	1,505	207
Manganese	0.102666667	276	119	0
Mercury	110.0327273	1.70E-02	5.03E-02	3.33E-02
Molybdenum	0.201438849			
Nickel	0.108914308	0.4	14.6	14.2
Selenium	1.121344	1.11	4.96	3.85
Silver	16.47072824	0.012	0.153	0.141
Sodium	0.00000549	5,409	5,612	203
Thallium	2.854901961	0.418	0.140	0
Tin	0.301075269			
Titanium	0.029319372		62	
Vanadium	0.28	1.4	25.2	23.8
Zinc	0.046886	9.4	33.6	24.2
Chloride	0.0000243	5,738	7,980	2,243
Sulfate	0.0000056	4,293	27,860	23,568
Nitrate/Nitrite	0.0032	225	234	9
Total Phosphorus	0			
Ammonia-N	0.00111	800	214	0
Fluoride	0.035	100		
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		PISCES Site A		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		PISCES Site B		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	872	2,787	1,915
Antimony	0.01225	0.19	5.50	5.31
Arsenic	3.469333333	0.2	20.0	19.8
Barium	0.001990757			
Beryllium	1.056603774	0.03	0.87	0.83
Boron	0.008341667	45.6	72.0	26.4
Cadmium	22.7584	0.012	0.290	0.278
Calcium	0.000028	2,843	6,168	3,325
Chromium	0.075696709	0.86	5.07	4.21
Cobalt	0.114285714			
Copper	0.623482222	0.8	32.5	31.7
Iron	0.0056	1,142	2,211	1,070
Lead	2.24	0.71	5.47	4.76
Magnesium	0.000865533	1,013	1,673	660
Manganese	0.102666667	43.4	51.9	8.5
Mercury	110.0327273	3.93E-03	3.69E-02	3.30E-02
Molybdenum	0.201438849			
Nickel	0.108914308	0.47	7.82	7.35
Selenium	1.121344	0.44	1.62	1.18
Silver	16.47072824	0.023	0	0
Sodium	0.00000549	2,484	4,762	2,278
Thallium	2.854901961	0.31	1.96	1.65
Tin	0.301075269			
Titanium	0.029319372		24	
Vanadium	0.28	2.0	22	20
Zinc	0.046886	4	63	59
Chloride	0.0000243	1,888	5,344	3,457
Sulfate	0.0000056	2,050	13,144	11,094
Nitrate/Nitrite	0.0032	191	198	6
Total Phosphorus	0			
Ammonia-N	0.00111	100	200	100
Fluoride	0.035	118	120	3
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		PISCES Site B		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		PISCES Site C		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	90	1,554	1,464
Antimony	0.01225	2.05	1.67	0
Arsenic	3.469333333	1	22	21
Barium	0.001990757		129	
Beryllium	1.056603774	0.019	0.404	0.385
Boron	0.008341667	156	148	0
Cadmium	22.7584	0.257	0.236	0
Calcium	0.000028	5,974	8,789	2,816
Chromium	0.075696709	1	7	6
Cobalt	0.114285714			
Copper	0.623482222	4.66	10.37	5.71
Iron	0.0056	107	919	812
Lead	2.24	4.14	3.35	0
Magnesium	0.000865533	3,054	3,357	303
Manganese	0.102666667	18.4	22.7	4.4
Mercury	110.0327273	2.81E-02	2.89E-02	7.88E-04
Molybdenum	0.201438849			
Nickel	0.108914308	0.82	8.04	7.22
Selenium	1.121344	0.91	3.06	2.15
Silver	16.47072824	0.083	0.165	0.082
Sodium	0.00000549	7,908	8,324	416
Thallium	2.854901961	0.948	0.206	0
Tin	0.301075269			
Titanium	0.029319372	42.2	54.3	12.1
Vanadium	0.28	0.4	18.2	17.8
Zinc	0.046886	14.1	36.7	22.5
Chloride	0.0000243	8,562	10,475	1,913
Sulfate	0.0000056	9,750	29,663	19,913
Nitrate/Nitrite	0.0032	114	131	17
Total Phosphorus	0			
Ammonia-N	0.00111	141	667	526
Fluoride	0.035	194	292	98
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		PISCES Site C		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		PISCES Site D		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	547	1,057	510
Antimony	0.01225	0.41	0.56	0.15
Arsenic	3.469333333	2.75	5.71	2.96
Barium	0.001990757	23.7	73.6	49.9
Beryllium	1.056603774	0.41	1.20	0.79
Boron	0.008341667	92	81	0
Cadmium	22.7584	0.024	0.143	0.119
Calcium	0.000028	22,787	29,997	7,210
Chromium	0.075696709	1.17	3.13	1.96
Cobalt	0.114285714			
Copper	0.623482222	10.9	4.1	0
Iron	0.0056	329	1,165	836
Lead	2.24	0.66	1.17	0.51
Magnesium	0.000865533	4,992	4,734	0
Manganese	0.102666667	27	26	0
Mercury	110.0327273	5.01E-02	7.71E-02	2.70E-02
Molybdenum	0.201438849			
Nickel	0.108914308	2	14	12
Selenium	1.121344	0.95	1.19	0.23
Silver	16.47072824	0.40	0.43	0.03
Sodium	0.00000549	5,838	6,171	334
Thallium	2.854901961	0.045	0.086	0.041
Tin	0.301075269			
Titanium	0.029319372	5	53	48
Vanadium	0.28	3.16	11.64	8.48
Zinc	0.046886	3.81	2.83	0
Chloride	0.0000243	6,600	6,714	114
Sulfate	0.0000056	28,200	30,286	2,086
Nitrate/Nitrite	0.0032	339	345	6
Total Phosphorus	0			
Ammonia-N	0.00111	108	114	6
Fluoride	0.035	125	143	18
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		PISCES Site D		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		PISCES Site E		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	282	519	237
Antimony	0.01225	12.0	14.1	2.1
Arsenic	3.469333333	18.8	21.2	2.4
Barium	0.001990757	90	85	0
Beryllium	1.056603774	0.021	0.068	0.048
Boron	0.008341667	4,695	5,051	357
Cadmium	22.7584	0.330	0.027	0
Calcium	0.000028	100,435	103,720	3,285
Chromium	0.075696709	0.69	1.38	0.69
Cobalt	0.114285714	0.74	0.25	0
Copper	0.623482222	2.27	2.67	0.40
Iron	0.0056	255	545	290
Lead	2.24	0.38	1.98	1.59
Magnesium	0.000865533	49,983	50,130	146
Manganese	0.102666667	29	18	0
Mercury	110.0327273	3.50E-03	3.75E-02	3.40E-02
Molybdenum	0.201438849			
Nickel	0.108914308	3.46	6.12	2.66
Selenium	1.121344	7.49	7.14	0
Silver	16.47072824	0.0024	0.41	0.41
Sodium	0.00000549	50,110	53,678	3,568
Thallium	2.854901961	0.175	0.002	0
Tin	0.301075269			
Titanium	0.029319372	5	76	71
Vanadium	0.28	8.55	12.79	4.24
Zinc	0.046886	3.08	3.55	0.47
Chloride	0.0000243	66,300	69,033	2,733
Sulfate	0.0000056	376,333	389,833	13,500
Nitrate/Nitrite	0.0032	50	50	0
Total Phosphorus	0			
Ammonia-N	0.00111	93	87	0
Fluoride	0.035	790	750	0
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		PISCES Site E		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		Frank E. Ratts Generating Station		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	6,010	1,860	0
Antimony	0.01225	0.70	5.54	4.85
Arsenic	3.469333333	3	24	21
Barium	0.001990757	100	78	0
Beryllium	1.056603774	0.240	0.463	0.223
Boron	0.008341667	166	1,450	1,284
Cadmium	22.7584	0.096	0.125	0.029
Calcium	0.000028	55,500	73,800	18,300
Chromium	0.075696709	7	3	0
Cobalt	0.114285714	2.05	2.40	0.35
Copper	0.623482222	172	2	0
Iron	0.0056	5,080	1,600	0
Lead	2.24	32	5	0
Magnesium	0.000865533	17,900	19,800	1,900
Manganese	0.102666667	192	302	110
Mercury	110.0327273	9.77E-03	2.80E-03	0.00E+00
Molybdenum	0.201438849	5	64	59
Nickel	0.108914308	18	12	0
Selenium	1.121344	0.84	1.14	0.30
Silver	16.47072824	0.051	0.022	0
Sodium	0.00000549	32,900	29,800	0
Thallium	2.854901961	0.08	0.35	0.27
Tin	0.301075269	5.89	0.11	0
Titanium	0.029319372	94.4	97.6	3.2
Vanadium	0.28	12	9	0
Zinc	0.046886	29	10	0
Chloride	0.0000243	41,700	40,800	0
Sulfate	0.0000056	49,300	115,000	65,700
Nitrate/Nitrite	0.0032	1,080	699	0
Total Phosphorus	0	330	30	0
Ammonia-N	0.00111	18	468	451
Fluoride	0.035			
Total Kjeldahl Nitrogen	0	3,600	1,800	0
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0	350,000	600,000	250,000
Total Suspended Solids	0	147,000	41,000	0
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228	3,600	2,270	0
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		Frank E. Ratts Generating Station		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		Stanton, Great River Energy		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	943	6,150	5,207
Antimony	0.01225	0.40	0.80	0.40
Arsenic	3.469333333	2.15	9.79	7.64
Barium	0.001990757	66	993	927
Beryllium	1.056603774	0.0285	0.0940	0.0655
Boron	0.008341667	168	289	121
Cadmium	22.7584	0.04	0.15	0.11
Calcium	0.000028	63,300	85,100	21,800
Chromium	0.075696709	1.1	5.2	4.1
Cobalt	0.114285714	0.313	0.595	0.282
Copper	0.623482222	2.27	6.84	4.57
Iron	0.0056	738	1,190	452
Lead	2.24	0.47	1.17	0.70
Magnesium	0.000865533	30,900	28,500	0
Manganese	0.102666667	50	31	0
Mercury	110.0327273	2.20E-03	1.63E-03	0.00E+00
Molybdenum	0.201438849	3	21	18
Nickel	0.108914308	2.58	2.88	0.30
Selenium	1.121344	0.74	1.71	0.97
Silver	16.47072824	0.01	0.02	0.01
Sodium	0.00000549	96,700	115,000	18,300
Thallium	2.854901961	0.020	0.176	0.156
Tin	0.301075269	0.055	0.190	0.135
Titanium	0.029319372	22	172	151
Vanadium	0.28	3.2	39.5	36.3
Zinc	0.046886	3.55	8.40	4.85
Chloride	0.0000243	10,200	10,400	200
Sulfate	0.0000056	274,000	368,000	94,000
Nitrate/Nitrite	0.0032	130	140	10
Total Phosphorus	0	50	100	50
Ammonia-N	0.00111	50	50	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0	2,500	2,500	0
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0	617,000	757,000	140,000
Total Suspended Solids	0	17,800	42,000	24,200
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			

		Stanton, Great River Energy		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		Tanners Creek, Indiana Michigan Power		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	607	5,540	4,933
Antimony	0.01225	0.165	0.873	0.708
Arsenic	3.469333333	1	5	4
Barium	0.001990757	47	424	377
Beryllium	1.056603774	0.08	1.96	1.88
Boron	0.008341667	40	65	25
Cadmium	22.7584	0.0285	0.0670	0.0385
Calcium	0.000028	38,100	38,500	400
Chromium	0.075696709	0.43	18.10	17.68
Cobalt	0.114285714	0.35	6.00	5.65
Copper	0.623482222	2	16	14
Iron	0.0056	514	2,190	1,676
Lead	2.24	0.56	5.16	4.60
Magnesium	0.000865533	12,800	12,600	0
Manganese	0.102666667	48.1	49.2	1.1
Mercury	110.0327273	1.98E-03	3.31E-03	1.33E-03
Molybdenum	0.201438849	1.82	6.73	4.91
Nickel	0.108914308	1.4	14.8	13.4
Selenium	1.121344	0.58	1.20	0.62
Silver	16.47072824	0.01	0.03	0.02
Sodium	0.00000549	18,100	18,400	300
Thallium	2.854901961	0.02	0.22	0.20
Tin	0.301075269	0.14	0.82	0.68
Titanium	0.029319372	9	496	487
Vanadium	0.28	1	26	25
Zinc	0.046886	3.1	10.2	7.1
Chloride	0.0000243	26,300	26,000	0
Sulfate	0.0000056	45,700	46,100	400
Nitrate/Nitrite	0.0032	1,360	1,380	20
Total Phosphorus	0	70	70	0
Ammonia-N	0.00111	130	90	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0	400	200	0
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0	241,000	234,000	0
Total Suspended Solids	0	8,000	148,000	140,000
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228	1,810	1,530	0
Oil and Grease	0			

		Tanners Creek, Indiana Michigan Power		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #1		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	170	2,900	2,730
Antimony	0.01225	0.5	1.2	0.7
Arsenic	3.469333333	1.6	6.9	5.3
Barium	0.001990757	32	190	158
Beryllium	1.056603774	0.5	1.1	0.6
Boron	0.008341667	100	405	305
Cadmium	22.7584	0.25	0.51	0.26
Calcium	0.000028	24,000	35,500	11,500
Chromium	0.075696709	0.5	9.6	9.1
Cobalt	0.114285714	0.5	1.0	0.5
Copper	0.623482222	2.8	11.0	8.2
Iron	0.0056	110	3,200	3,090
Lead	2.24	0.50	2.25	1.75
Magnesium	0.000865533	6,600	6,250	0
Manganese	0.102666667	33	60	27
Mercury	110.0327273			
Molybdenum	0.201438849	7	31	24
Nickel	0.108914308	0.5	14.0	13.5
Selenium	1.121344	1	3.5	2.5
Silver	16.47072824	0.25	0.25	0
Sodium	0.00000549	8,200	8,000	0
Thallium	2.854901961	0.5	0.5	0
Tin	0.301075269	0.5	0.5	0
Titanium	0.029319372			
Vanadium	0.28	2	42	40
Zinc	0.046886	5	27	22
Chloride	0.0000243	9,100	10,800	1,700
Sulfate	0.0000056	21,000	58,500	37,500
Nitrate/Nitrite	0.0032	190	190	0
Total Phosphorus	0	160	430	270
Ammonia-N	0.00111	50	50	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #1		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #2		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	320	1,200	880
Antimony	0.01225			
Arsenic	3.469333333	0.5	5.2	4.7
Barium	0.001990757			
Beryllium	1.056603774	1.0	1.0	0
Boron	0.008341667	100	100	0
Cadmium	22.7584	0.25	0.25	0
Calcium	0.000028	36,000	44,000	8,000
Chromium	0.075696709	0.5	1.3	0.8
Cobalt	0.114285714			
Copper	0.623482222	3.9	3.5	0
Iron	0.0056	310	450	140
Lead	2.24			
Magnesium	0.000865533	11,000	11,000	0
Manganese	0.102666667	90	110	20
Mercury	110.0327273			
Molybdenum	0.201438849	2.5	8.0	5.5
Nickel	0.108914308	1.3	3.6	2.3
Selenium	1.121344	0.5	10.0	9.5
Silver	16.47072824			
Sodium	0.00000549			
Thallium	2.854901961	0.5	0.5	0
Tin	0.301075269			
Titanium	0.029319372			
Vanadium	0.28	1	28	27
Zinc	0.046886	5	5	0
Chloride	0.0000243	5,100	6,200	1,100
Sulfate	0.0000056	23,000	76,000	53,000
Nitrate/Nitrite	0.0032	520	390	0
Total Phosphorus	0	50	50	0
Ammonia-N	0.00111	50	130	80
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #2		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #3		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	182	3,220	3,038
Antimony	0.01225	1.0	6.4	5.4
Arsenic	3.469333333	1	20	19
Barium	0.001990757	18.4	110	91.6
Beryllium	1.056603774	0.05	1.50	1.45
Boron	0.008341667	66	99	33
Cadmium	22.7584	0.1	0.1	0
Calcium	0.000028	10,600	14,000	3,400
Chromium	0.075696709	0.33	7.10	6.77
Cobalt	0.114285714	0.36	3.42	3.06
Copper	0.623482222	3.03	15.40	12.37
Iron	0.0056	663	1,870	1,207
Lead	2.24	0.6	7.2	6.6
Magnesium	0.000865533	2,250	2,650	400
Manganese	0.102666667	82	109	27
Mercury	110.0327273	1.59E-03	6.05E-03	4.46E-03
Molybdenum	0.201438849	1.2	7.5	6.2
Nickel	0.108914308	1.0	7.9	6.9
Selenium	1.121344	0.10	5.57	5.47
Silver	16.47072824	0.1	0.1	0
Sodium	0.00000549	13,000	14,000	1,000
Thallium	2.854901961	0.10	0.54	0.44
Tin	0.301075269	1.0	1.0	0
Titanium	0.029319372	8	221	213
Vanadium	0.28	0.7	26.4	25.7
Zinc	0.046886	7	17	10
Chloride	0.0000243	13,300	14,300	1,000
Sulfate	0.0000056	10,500	56,700	46,200
Nitrate/Nitrite	0.0032	2,660	2,490	0
Total Phosphorus	0	40	110	70
Ammonia-N	0.00111	60	80	20
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #3		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #4		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216			
Antimony	0.01225			
Arsenic	3.469333333	1.2	19.7	18.5
Barium	0.001990757			
Beryllium	1.056603774			
Boron	0.008341667	297	3,440	3,143
Cadmium	22.7584	0.14	0.20	0.06
Calcium	0.000028			
Chromium	0.075696709	0.9	5.0	4.1
Cobalt	0.114285714			
Copper	0.623482222	3	14	11
Iron	0.0056	176	2,130	1,954
Lead	2.24	0.25	1.39	1.14
Magnesium	0.000865533			
Manganese	0.102666667	43	78	36
Mercury	110.0327273	2.21E-03	1.41E-02	1.19E-02
Molybdenum	0.201438849			
Nickel	0.108914308			
Selenium	1.121344	0.2	6.2	6.0
Silver	16.47072824			
Sodium	0.00000549			
Thallium	2.854901961			
Tin	0.301075269			
Titanium	0.029319372			
Vanadium	0.28			
Zinc	0.046886	14	19	5
Chloride	0.0000243	5,010	6,110	1,100
Sulfate	0.0000056			
Nitrate/Nitrite	0.0032			
Total Phosphorus	0	50	130	80
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #4		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #5		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216			
Antimony	0.01225			
Arsenic	3.469333333	0.78	6.19	5.41
Barium	0.001990757			
Beryllium	1.056603774			
Boron	0.008341667			
Cadmium	22.7584			
Calcium	0.000028			
Chromium	0.075696709	1.16	1.72	0.56
Cobalt	0.114285714			
Copper	0.623482222	1.55	2.77	1.22
Iron	0.0056	517	189	0
Lead	2.24	0.28	0.11	0
Magnesium	0.000865533			
Manganese	0.102666667	85	54	0
Mercury	110.0327273	2.61E-03	2.47E-03	0.00E+00
Molybdenum	0.201438849			
Nickel	0.108914308			
Selenium	1.121344			
Silver	16.47072824			
Sodium	0.00000549			
Thallium	2.854901961			
Tin	0.301075269			
Titanium	0.029319372			
Vanadium	0.28			
Zinc	0.046886	8	5	0
Chloride	0.0000243	3,300	3,900	600
Sulfate	0.0000056			
Nitrate/Nitrite	0.0032			
Total Phosphorus	0	50	30	0
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			

		UWAG Plant #5		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #6		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216			
Antimony	0.01225			
Arsenic	3.469333333	0.6	25.7	25.1
Barium	0.001990757			
Beryllium	1.056603774			
Boron	0.008341667	345	1,122	777
Cadmium	22.7584	0.08	0.21	0.13
Calcium	0.000028			
Chromium	0.075696709	1.14	1.52	0.38
Cobalt	0.114285714			
Copper	0.623482222	1.01	3.56	2.55
Iron	0.0056	246	45	0
Lead	2.24	0.24	0.19	0
Magnesium	0.000865533			
Manganese	0.102666667	35	8	0
Mercury	110.0327273	8.00E-04	4.03E-03	3.23E-03
Molybdenum	0.201438849			
Nickel	0.108914308			
Selenium	1.121344	0.15	2.10	1.95
Silver	16.47072824			
Sodium	0.00000549			
Thallium	2.854901961			
Tin	0.301075269			
Titanium	0.029319372			
Vanadium	0.28			
Zinc	0.046886	5	4	0
Chloride	0.0000243	20,900	26,000	5,100
Sulfate	0.0000056			
Nitrate/Nitrite	0.0032			
Total Phosphorus	0	30	70	40
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #6		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #7		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	180	85	0
Antimony	0.01225	5	5	0
Arsenic	3.469333333	1	1	0
Barium	0.001990757	29	311	282
Beryllium	1.056603774	0.5	0.5	0
Boron	0.008341667	952	1,300	348
Cadmium	22.7584	0.5	0.5	0
Calcium	0.000028	94,300	266,000	171,700
Chromium	0.075696709	1	1	0
Cobalt	0.114285714	0.5	0.5	0
Copper	0.623482222	0.5	0.5	0
Iron	0.0056	1,040	988	0
Lead	2.24	0.50	2.88	2.38
Magnesium	0.000865533	207,000	27,600	0
Manganese	0.102666667	148	8	0
Mercury	110.0327273	3.87E-03	1.00E-04	0.00E+00
Molybdenum	0.201438849	2	60	58
Nickel	0.108914308	0.5	0.5	0
Selenium	1.121344	1.0	5.8	4.8
Silver	16.47072824	2.0	2.0	0
Sodium	0.00000549	2,630,000	923,000	0
Thallium	2.854901961	0.5	0.5	0
Tin	0.301075269			
Titanium	0.029319372	1	1	0
Vanadium	0.28	1.00	6.55	5.55
Zinc	0.046886	1	1	0
Chloride	0.0000243	4,310,000	1,830,000	0
Sulfate	0.0000056	619,000	395,000	0
Nitrate/Nitrite	0.0032	290	90	0
Total Phosphorus	0	40	20	0
Ammonia-N	0.00111	25	25	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #7		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #9		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	35	148	113
Antimony	0.01225	0.5	0.5	0
Arsenic	3.469333333	0.50	3.03	2.53
Barium	0.001990757	18	40	22
Beryllium	1.056603774	0.5	0.5	0
Boron	0.008341667	72	67	0
Cadmium	22.7584	0.5	0.5	0
Calcium	0.000028	8,260	8,140	0
Chromium	0.075696709	0.5	0.5	0
Cobalt	0.114285714	0.5	0.5	0
Copper	0.623482222	1.4	7.9	6.6
Iron	0.0056	49	101	52
Lead	2.24	0.5	0.5	0
Magnesium	0.000865533	3,550	3,470	0
Manganese	0.102666667	13	13	0
Mercury	110.0327273	2.80E-04	3.80E-04	1.00E-04
Molybdenum	0.201438849	2.10	3.09	0.99
Nickel	0.108914308	0.50	1.59	1.09
Selenium	1.121344	0.5	0.5	0
Silver	16.47072824	0.5	0.5	0
Sodium	0.00000549	6,620	6,420	0
Thallium	2.854901961	0.5	0.5	0
Tin	0.301075269	5	5	0
Titanium	0.029319372			
Vanadium	0.28			
Zinc	0.046886	34	5	0
Chloride	0.0000243			
Sulfate	0.0000056			
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #9		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #10		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	64	596	532
Antimony	0.01225	0.5	0.5	0
Arsenic	3.469333333	0.5	4.4	3.9
Barium	0.001990757	23	35	12
Beryllium	1.056603774	0.5	0.5	0
Boron	0.008341667	86	97	11
Cadmium	22.7584	0.5	0.5	0
Calcium	0.000028	5,160	6,830	1,670
Chromium	0.075696709	0.50	1.71	1.21
Cobalt	0.114285714	0.5	0.5	0
Copper	0.623482222	1.26	3.62	2.36
Iron	0.0056	245	598	353
Lead	2.24	0.5	0.5	0.0
Magnesium	0.000865533	2,200	2,340	140
Manganese	0.102666667	680	615	0
Mercury	110.0327273	7.50E-05	8.00E-04	7.25E-04
Molybdenum	0.201438849	0.50	1.79	1.29
Nickel	0.108914308	0.50	1.67	1.17
Selenium	1.121344	0.50	1.16	0.66
Silver	16.47072824	0.5	0.5	0
Sodium	0.00000549	4,230	4,480	250
Thallium	2.854901961	0.5	0.5	0
Tin	0.301075269	5	5	0
Titanium	0.029319372			
Vanadium	0.28			
Zinc	0.046886	0.50	1.45	0.95
Chloride	0.0000243			
Sulfate	0.0000056			
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #10		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #11		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	133	1,608	1,475
Antimony	0.01225	0.09	0.21	0.12
Arsenic	3.469333333	0.59	2.79	2.20
Barium	0.001990757	18	84	67
Beryllium	1.056603774	0.01	0.14	0.13
Boron	0.008341667	27	66	39
Cadmium	22.7584	0.13	0.13	0
Calcium	0.000028	37,000	40,900	3,900
Chromium	0.075696709	2.65	2.90	0.25
Cobalt	0.114285714	0.05	0.40	0.35
Copper	0.623482222	9.56	11.37	1.81
Iron	0.0056	129	567	438
Lead	2.24	0.32	0.88	0.56
Magnesium	0.000865533	10,500	10,500	0
Manganese	0.102666667	4.30	4.83	0.53
Mercury	110.0327273	1.56E-03	2.81E-03	1.25E-03
Molybdenum	0.201438849	0.97	3.29	2.32
Nickel	0.108914308	2.03	2.33	0.30
Selenium	1.121344	0.31	0.59	0.28
Silver	16.47072824	0.01	0.01	0
Sodium	0.00000549	8,100	8,060	0
Thallium	2.854901961	0.80	0.32	0
Tin	0.301075269	3.22	3.25	0.03
Titanium	0.029319372	2	60	58
Vanadium	0.28	0.6	8.8	8.2
Zinc	0.046886	21	16	0
Chloride	0.0000243			
Sulfate	0.0000056			
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3
Bottom ash water quality characterization data (continued)

		UWAG Plant #12		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216			
Antimony	0.01225			
Arsenic	3.469333333	4	42	39
Barium	0.001990757			
Beryllium	1.056603774			
Boron	0.008341667			
Cadmium	22.7584	1	1	0
Calcium	0.000028			
Chromium	0.075696709	4	4	0
Cobalt	0.114285714			
Copper	0.623482222	5	4	0
Iron	0.0056			
Lead	2.24	2	1	0
Magnesium	0.000865533			
Manganese	0.102666667			
Mercury	110.0327273	1.00E-02	1.66E-03	0.00E+00
Molybdenum	0.201438849			
Nickel	0.108914308	15	21	6
Selenium	1.121344	3.5	8.0	4.5
Silver	16.47072824			
Sodium	0.00000549			
Thallium	2.854901961			
Tin	0.301075269			
Titanium	0.029319372			
Vanadium	0.28			
Zinc	0.046886	41	36	0
Chloride	0.0000243			
Sulfate	0.0000056	78,000	139,000	61,000
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #12		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #13		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	240	1,220	980
Antimony	0.01225	1	1	0
Arsenic	3.469333333	0.5	7.5	7.0
Barium	0.001990757	21	260	239
Beryllium	1.056603774	2.5	2.5	0
Boron	0.008341667	50	320	270
Cadmium	22.7584	0.1	0.1	0
Calcium	0.000028			
Chromium	0.075696709	5	5	0
Cobalt	0.114285714	5	5	0
Copper	0.623482222	1.3	3.8	2.5
Iron	0.0056	470	260	0
Lead	2.24	1.2	1.4	0.2
Magnesium	0.000865533	9,200	10,000	800
Manganese	0.102666667	12	5	0
Mercury	110.0327273			
Molybdenum	0.201438849	50	50	0
Nickel	0.108914308	0.5	2.0	1.5
Selenium	1.121344	1	5	4
Silver	16.47072824	0.1	0.1	0
Sodium	0.00000549			
Thallium	2.854901961	1	1	0
Tin	0.301075269	500	500	0
Titanium	0.029319372	50	50	0
Vanadium	0.28			
Zinc	0.046886	10	10	0
Chloride	0.0000243			
Sulfate	0.0000056	22,000	57,000	35,000
Nitrate/Nitrite	0.0032	450	520	70
Total Phosphorus	0	30	80	50
Ammonia-N	0.00111	80	210	130
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #13		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

		UWAG Plant #13		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #14		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	190	390	200
Antimony	0.01225	10	10	0
Arsenic	3.469333333	10	10	0
Barium	0.001990757	64	110	46
Beryllium	1.056603774	3	3	0
Boron	0.008341667	50	100	50
Cadmium	22.7584	1	1	0
Calcium	0.000028			
Chromium	0.075696709	2	2	0
Cobalt	0.114285714	2.5	6.0	3.5
Copper	0.623482222	5	5	0
Iron	0.0056	210	140	0
Lead	2.24	5	5	0
Magnesium	0.000865533	28,000	30,000	2,000
Manganese	0.102666667	28	180	152
Mercury	110.0327273	3.20E-03	1.30E-03	0.00E+00
Molybdenum	0.201438849	5	5	0
Nickel	0.108914308	5	5	0
Selenium	1.121344	5	5	0
Silver	16.47072824	5	5	0
Sodium	0.00000549			
Thallium	2.854901961	5	5	0
Tin	0.301075269	30	30	0
Titanium	0.029319372	2.5	6.0	3.5
Vanadium	0.28			
Zinc	0.046886	5	5	0
Chloride	0.0000243			
Sulfate	0.0000056			
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #14		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #15		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	4,700	2,800	0
Antimony	0.01225	2.5	2.5	0
Arsenic	3.469333333	2.5	2.5	0
Barium	0.001990757	100	100	0
Beryllium	1.056603774	2.5	2.5	0
Boron	0.008341667	300	700	400
Cadmium	22.7584	2.5	2.5	0
Calcium	0.000028			
Chromium	0.075696709	8	2.5	0
Cobalt	0.114285714	2.5	2.5	0
Copper	0.623482222	11	5	0
Iron	0.0056	4,400	2,500	0
Lead	2.24	5	5	0
Magnesium	0.000865533	15,200	13,600	0
Manganese	0.102666667	220	80	0
Mercury	110.0327273			
Molybdenum	0.201438849	2.5	40.0	37.5
Nickel	0.108914308	16	12	0
Selenium	1.121344	11	5	0
Silver	16.47072824	2.5	12.0	9.5
Sodium	0.00000549			
Thallium	2.854901961	4	6	2
Tin	0.301075269	2.5	2.5	0
Titanium	0.029319372	110	100	0
Vanadium	0.28			
Zinc	0.046886	35	44	9
Chloride	0.0000243			
Sulfate	0.0000056			
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			

		UWAG Plant #15		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #16		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	1,120	1,960	840
Antimony	0.01225	50	50	0
Arsenic	3.469333333	2.5	2.5	0
Barium	0.001990757	69	195	127
Beryllium	1.056603774	0.5	0.5	0
Boron	0.008341667	50	179	129
Cadmium	22.7584	0.13	0.20	0.07
Calcium	0.000028			
Chromium	0.075696709	3.49	4.62	1.13
Cobalt	0.114285714			
Copper	0.623482222	2.5	2.5	0
Iron	0.0056	1,910	2,580	670
Lead	2.24	2.79	3.74	0.95
Magnesium	0.000865533	20,300	24,600	4,300
Manganese	0.102666667	172	113	0
Mercury	110.0327273			
Molybdenum	0.201438849	25	25	0
Nickel	0.108914308	5	5	0
Selenium	1.121344	2.5	2.5	0
Silver	16.47072824	0.5	0.5	0
Sodium	0.00000549			
Thallium	2.854901961	1	1	0
Tin	0.301075269	50	50	0
Titanium	0.029319372	25		
Vanadium	0.28			
Zinc	0.046886	10	30	20
Chloride	0.0000243	17,300	27,500	10,200
Sulfate	0.0000056	39,400	60,600	21,200
Nitrate/Nitrite	0.0032	2,010	754	0
Total Phosphorus	0	193	182	0
Ammonia-N	0.00111	2,500	225	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			

		UWAG Plant #16		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #17		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	50	2,200	2,150
Antimony	0.01225	50	50	0
Arsenic	3.469333333	40	40	0
Barium	0.001990757	44	200	156
Beryllium	1.056603774	5	5	0
Boron	0.008341667	50	476	426
Cadmium	22.7584	10	10	0
Calcium	0.000028			
Chromium	0.075696709	10	10	0
Cobalt	0.114285714	10	10	0
Copper	0.623482222	10	10	0
Iron	0.0056	717	253	0
Lead	2.24	50	50	0
Magnesium	0.000865533	20,200	17,500	0
Manganese	0.102666667	54	13	0
Mercury	110.0327273			
Molybdenum	0.201438849			
Nickel	0.108914308	25	25	0
Selenium	1.121344	75	75	0
Silver	16.47072824	10	10	0
Sodium	0.00000549			
Thallium	2.854901961	500	500	0
Tin	0.301075269			
Titanium	0.029319372		25	
Vanadium	0.28			
Zinc	0.046886	10	10	0
Chloride	0.0000243	25,600	31,500	5,900
Sulfate	0.0000056	41,600	87,800	46,200
Nitrate/Nitrite	0.0032	2,080	2,240	160
Total Phosphorus	0	50	50	0
Ammonia-N	0.00111	250	250	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			

		UWAG Plant #17		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data (continued)

		UWAG Plant #18		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	480	550	70
Antimony	0.01225	0.5	0.5	0
Arsenic	3.469333333	2.10	1.85	0
Barium	0.001990757	42	39	0
Beryllium	1.056603774	1	1	0
Boron	0.008341667	100	100	0
Cadmium	22.7584	0.25	0.25	0
Calcium	0.000028	30,000	31,000	1,000
Chromium	0.075696709	0.5	0.5	0
Cobalt	0.114285714	0.5	0.5	0
Copper	0.623482222	2	5	4
Iron	0.0056	300	350	50
Lead	2.24	1	1	0
Magnesium	0.000865533	8,900	9,200	300
Manganese	0.102666667	50	51	1
Mercury	110.0327273			
Molybdenum	0.201438849	2.5	2.5	0
Nickel	0.108914308	0.5	1.0	0.5
Selenium	1.121344	0.5	0.5	0
Silver	16.47072824	0.25	0.25	0
Sodium	0.00000549	6,000	6,250	250
Thallium	2.854901961	0.50	0.50	0
Tin	0.301075269	0.50	0.50	0
Titanium	0.029319372			
Vanadium	0.28	3.4	3.2	0
Zinc	0.046886	5	5	0
Chloride	0.0000243	5,200	5,400	200
Sulfate	0.0000056	22,000	22,500	500
Nitrate/Nitrite	0.0032	380	415	35
Total Phosphorus	0	130	100	0
Ammonia-N	0.00111	50	50	0
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			

		UWAG Plant #18		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data (continued)

		UWAG Plant #19		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216			
Antimony	0.01225			
Arsenic	3.469333333	5	5	0
Barium	0.001990757			
Beryllium	1.056603774			
Boron	0.008341667	100	700	600
Cadmium	22.7584			
Calcium	0.000028	48,000	140,000	92,000
Chromium	0.075696709			
Cobalt	0.114285714			
Copper	0.623482222			
Iron	0.0056	705	3,535	2,830
Lead	2.24			
Magnesium	0.000865533	17,000	24,500	7,500
Manganese	0.102666667	82	73	0
Mercury	110.0327273	1.80E-03	3.25E-02	3.07E-02
Molybdenum	0.201438849			
Nickel	0.108914308			
Selenium	1.121344	2.5	2.5	0
Silver	16.47072824			
Sodium	0.00000549	35,000	70,500	35,500
Thallium	2.854901961			
Tin	0.301075269			
Titanium	0.029319372			
Vanadium	0.28			
Zinc	0.046886			
Chloride	0.0000243	45,000	101,000	56,000
Sulfate	0.0000056	120,000	435,000	315,000
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #20		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	291	4,149	3,858
Antimony	0.01225	1.8	4.5	2.8
Arsenic	3.469333333	3	113	110
Barium	0.001990757	20	71	51
Beryllium	1.056603774	0.55	1.40	0.85
Boron	0.008341667	184	247	63
Cadmium	22.7584	0.81	0.72	0
Calcium	0.000028	4,273	16,129	11,856
Chromium	0.075696709	2.5	6.7	4.2
Cobalt	0.114285714	1.0	4.7	3.7
Copper	0.623482222	1.0	27.7	26.7
Iron	0.0056	847	2,594	1,747
Lead	2.24	2.5	8.1	5.6
Magnesium	0.000865533	992	1,632	640
Manganese	0.102666667	48	43	0
Mercury	110.0327273	6.45E-03	2.79E-02	2.14E-02
Molybdenum	0.201438849	1	19	18
Nickel	0.108914308	4	6	2
Selenium	1.121344	60	43	0
Silver	16.47072824	3.5	3.5	0
Sodium	0.00000549	10,020	17,773	7,753
Thallium	2.854901961	1.75	3.90	2.15
Tin	0.301075269	2.9	2.6	0
Titanium	0.029319372	10	178	168
Vanadium	0.28	1	59	58
Zinc	0.046886	15	34	19
Chloride	0.0000243	11,600	19,200	7,600
Sulfate	0.0000056	16,100	26,000	9,900
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		UWAG Plant #21		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Aluminum	0.064691216	674	2,669	1,995
Antimony	0.01225	1.9	3.3	1.4
Arsenic	3.469333333	4	34	31
Barium	0.001990757	28	179	151
Beryllium	1.056603774	0.9	1.0	0.1
Boron	0.008341667	75	182	107
Cadmium	22.7584	1.15	1.50	0.35
Calcium	0.000028	7,100	11,907	4,807
Chromium	0.075696709	3	15	13
Cobalt	0.114285714	1.25	3.30	2.05
Copper	0.623482222	5	62	57
Iron	0.0056	669	1,834	1,165
Lead	2.24	3	7	4
Magnesium	0.000865533	3,156	3,379	223
Manganese	0.102666667	87	144	57
Mercury	110.0327273	1.66E-03	5.78E-03	4.12E-03
Molybdenum	0.201438849	2.7	5.8	3.1
Nickel	0.108914308	5	16	11
Selenium	1.121344	2.5	8.2	5.7
Silver	16.47072824	3.0	2.2	0
Sodium	0.00000549	21,105	22,800	1,695
Thallium	2.854901961	2.1	2.2	0.1
Tin	0.301075269	2.5	2.5	0
Titanium	0.029319372	25	135	110
Vanadium	0.28	2	31	29
Zinc	0.046886	13	32	19
Chloride	0.0000243	16,700	17,200	500
Sulfate	0.0000056	21,000	28,000	7,000
Nitrate/Nitrite	0.0032			
Total Phosphorus	0			
Ammonia-N	0.00111			
Fluoride	0.035			
Total Kjeldahl Nitrogen	0			
Biochemical Oxygen Demand	0			
Sulfide (as S)	2.801446667			
Sulfite (as SO3)	0			
Cyanide	1.116923077			
Total Dissolved Solids	0			
Total Suspended Solids	0			
Hexane Extractable Material	0			
Nitrogen, Total Organic (as N)	0.00228			
Oil and Grease	0			
Silica-Gel Treated Hexane Extractable Material	0			

		UWAG Plant #21		
		Source Water	BA Sluice	BA Sluice Minus Source Water
Analyte	TWF	Concentration (ug/L)	Concentration (ug/L)	Concentration (ug/L)
Hexavalent Chromium	0.516557576			
Silica	0			
Yttrium	0			
Bromide	0			

Table H-3 (continued)
Bottom ash water quality characterization data

		Bottom Ash Subtracting Out Source Water Mean	Bottom Ash Not Subtracting Out Source Water Mean	Bottom Ash Subtracting Out Source Water Median	Bottom Ash Not Subtracting Out Source Water Median
Analyte	TWF	Concentration (µg/L)	Concentration (µg/L)	Concentration (µg/L)	Concentration (µg/L))
Aluminum	0.064691216	1,496	2,262	1,222	1,910
Antimony	0.01225	1.02	6.76	0.02	1.67
Arsenic	3.469333333	11.84	15.63	4.70	7.42
Barium	0.001990757	130	178	64	105
Beryllium	1.056603774	0.32	1.07	0.08	0.68
Boron	0.008341667	297	653	50	179
Cadmium	22.7584	0.05	0.75	0.00	0.24
Calcium	0.000028	17,046	47,695	3,650	29,699
Chromium	0.075696709	3.20	5.15	1.17	4.14
Cobalt	0.114285714	1.07	2.66	0.22	1.94
Copper	0.623482222	7.60	10.68	2.43	5.79
Iron	0.0056	873	1,560	445	1,177
Lead	2.24	1.37	4.48	0.51	2.25
Magnesium	0.000865533	736	12,549	146	9,200
Manganese	0.102666667	14.94	87.91	0.00	53.06
Mercury	110.0327273	8.73E-03	1.47E-02	1.29E-03	4.89E-03
Molybdenum	0.201438849	12.08	19.96	2.71	7.73
Nickel	0.108914308	4.23	8.37	1.81	6.12
Selenium	1.121344	1.85	7.14	0.64	2.78
Silver	16.47072824	0.41	1.53	0.00	0.25
Sodium	0.00000549	3,502	67,078	334	17,773
Thallium	2.854901961	0.29	20.26	0.00	0.50
Tin	0.301075269	0.05	33.58	0.00	1.75
Titanium	0.029319372	97.1	111.7	71.10	79.55
Vanadium	0.28	18.2	21.8	17.82	21.92
Zinc	0.046886	7.5	16.7	0.30	10.00
Chloride	0.0000243	4,236	97,994	1,050	15,750
Sulfate	0.0000056	38,824	114,843	21,200	58,400
Nitrate/Nitrite	0.0032	18.64	633	6.25	390
Total Phosphorus	0	38.59	108	30.00	70
Ammonia-N	0.00111	69.07	166	0.00	114
Fluoride	0.035	29.59	326	10.18	217
Total Kjeldahl Nitrogen	0	63.33	980	15.00	575
Biochemical Oxygen Demand	0				
Sulfide (as S)	2.801446667				
Sulfite (as SO3)	0				
Cyanide	1.116923077				
Total Dissolved Solids	0	68,667	370,000	11,000	238,500
Total Suspended Solids	0	34,700	62,333	19,500	41,500
Hexane Extractable Material	0				
Nitrogen, Total Organic (as N)	0.00228	60.0	1,380	0.00	1,420
Oil and Grease	0				

Table H-3 (continued)
Bottom ash water quality characterization data

		Bottom Ash Subtracting Out Source Water Mean	Bottom Ash Not Subtracting Out Source Water Mean	Bottom Ash Subtracting Out Source Water Median	Bottom Ash Not Subtracting Out Source Water Median
Analyte	**TWF**	**Concentration (µg/L)**	**Concentration (µg/L)**	**Concentration (µg/L)**	**Concentration (µg/L))**
Silica-Gel Treated Hexane Extractable Material	0				
Hexavalent Chromium	0.516557576				
Silica	0				
Yttrium	0				
Bromide	0	5,104	5,104		

EPRI's single-pass bromide value (highlighted in orange) taken from EPA's average bottom ash concentration value.

Table H-4
Bottom ash pollutant reduction estimate

		Single Pass Bottom Ash Subtracting Source Water Mean			Single Pass Bottom Ash Not Subtracting Out Source Water Mean			Single Pass Bottom Ash Subtracting Source Water Median		Single Pass Bottom Ash Not Subtracting Out Source Water Median	
Analyte	**TWF**	**lb/yr**	**TWF* µg/L**	**TWPE/yr**	**lb/yr**	**TWF* µg/L**	**TWPE/yr**	**TWF* µg/L**	**TWPE/yr**	**TWF* µg/L**	**TWPE/yr**
Aluminum	0.064691216	598,097	96.8	38,692	904,516	146	58,514	79.0	31,604	124	49,403
Antimony	0.01225	407	0.0125	4.98	2,703	0.1	33	2.21E-04	0.0882	0.020	8.17
Arsenic	3.469333333	4,732.36	41.1	16,418	6,249	54.2	21,680	16.3	6,520	25.7	10,287
Barium	0.001990757	52,085.45	0.259	104	70,989	0.4	141	0.127	50.9	0.209	83.6
Beryllium	1.056603774	126.65	0.335	134	430	1.14	454	0.087	35.0	0.721	288
Boron	0.008341667	118,655	2.48	990	261,130	5.45	2,178	0.417	167	1.49	597
Cadmium	22.7584	21.31	1.21	485	300	17.1	6,833	0	0	5.38	2,151
Calcium	0.000028	6,815,464	0.477	191	19,069,911	1.34	534	0.102	40.9	0.832	332
Chromium	0.075696709	1,278	0.242	96.8	2,060	0.390	156	0.089	35.4	0.313	125
Cobalt	0.114285714	426	0.122	48.7	1,064	0.304	122	0.025	10.0	0.221	88.4
Copper	0.623482222	3,038	4.74	1,894	4,269	6.66	2,661	1.52	606	3.61	1,443
Iron	0.0056	348,865	4.89	1,954	623,904	8.74	3,494	2.49	997	6.59	2,636
Lead	2.24	548	3.07	1,227	1,790	10.0	4,009	1.13	454	5.04	2,015
Magnesium	0.000865533	294,084	0.637	255	5,017,625	10.9	4,343	0.127	50.7	7.96	3,184
Manganese	0.102666667	5,975	1.53	613	35,151	9.03	3,609	0	0	5.45	2,178
Mercury	110.0327273	3.49	0.961	384	5.87	1.62	646	0.142	56.8	0.538	215
Molybdenum	0.201438849	4,828	2.43	973	7,981	4.02	1,608	0.546	218	1.56	622
Nickel	0.108914308	1,690	0.460	184	3,348	0.912	365	0.197	78.8	0.667	267
Selenium	1.121344	739	2.073	829	2,853	8.00	3,199	0.718	287	3.12	1,246
Silver	16.47072824	163	6.718	2,686	611	25.2	10,061	0	0	4.12	1,646
Sodium	0.00000549	1,400,287	0.0192	8	26,819,863	0.368	147	0.002	0.732	0.098	39.0
Thallium	2.854901961	115	0.821	328	8,099	57.8	23,122	0	0	1.43	571
Tin	0.301075269	18.8	0.0141	6	13,428	10.1	4,043	0	0	0.527	211
Titanium	0.029319372	38,810	2.85	1,138	44,673	3.28	1,310	2.08	833	2.33	933
Vanadium	0.28	7,283	5.10	2,039	8,732	6.12	2,445	4.99	1,996	6.14	2,454
Zinc	0.046886	2,982	0.350	140	6,693	0.785	314	0.014	5.62	0.469	187
Chloride	0.0000243	1,693,629	0.103	41.2	39,181,263	2.38	952	0.026	10.2	0.383	153
Sulfate	0.0000056	15,523,262	0.217	86.9	45,917,981	0.643	257	0.119	47.5	0.327	131

		Single Pass Bottom Ash Subtracting Source Water Mean			Single Pass Bottom Ash Not Subtracting Out Source Water Mean			Single Pass Bottom Ash Subtracting Source Water Median		Single Pass Bottom Ash Not Subtracting Out Source Water Median	
Analyte	**TWF**	**lb/yr**	**TWF* µg/L**	**TWPE/yr**	**lb/yr**	**TWF* µg/L**	**TWPE/yr**	**TWF* µg/L**	**TWPE/yr**	**TWF* µg/L**	**TWPE/yr**
Nitrate/Nitrite	0.0032	7,454	0.060	23.9	253,077	2.03	810	0.020	8.00	1.25	499
Total Phosphorus	0	15,429			43,064						
Ammonia-N	0.00111	27,615	0.0767	30.7	66,383	0.184	73.7	0	0	0.127	50.6
Fluoride	0.035	11,831	1.04	414	130,431	11.4	4,565	0.356	142	7.61	3,043
Total Kjeldahl Nitrogen	0	25,323			391,836						
Biochemical Oxygen Demand	0										
Sulfide (as S)	2.801446667										
Sulfite (as SO3)	0										
Cyanide	1.116923077										
Total Dissolved Solids	0										
Total Suspended Solids	0										
Hexane Extractable Material	0										
Nitrogen, Total Organic (as N)	0.00228	23,990			551,770						
Oil and Grease	0										
Silica-Gel Treated Hexane Extractable Material	0										
Hexavalent Chromium	0.516557576										
Silica	0										
Yttrium	0										
Bromide		2,040,648	0	0	2,040,648	0.0	0				
	Total	**29,069,902**	**181**	**72,417**	**141,494,829**	**407**	**162,679**	**111**	**44,254**	**218**	**87,088**
					Source Water	105,286,795	84,531				

Table H-4 (continued)
Bottom ash pollutant reduction estimate

		BA Close-Loop Water for 10% Purge Subtracting Source Water Median				BA Close-Loop Water for 10% Purge Not Subtracting Source Water Median			
Analyte	TWF	µg/L	lb/yr	TWF* µg/L	TWPE/yr	µg/L	lb/yr	TWF µg/L	TWPE/yr
Aluminum	0.064691216	3,168	80,423	205	5,203	3,293	83,585	213	5,407
Antimony	0.01225	0	0	0	0	5	123	0	2
Arsenic	3.469333333	12	302	41	1,049	13	329	45	1,142
Barium	0.001990757	763	19,360	2	39	838	21,261	2	42
Beryllium	1.056603774	0	0	0	0	0	5	0	6
Boron	0.008341667	754	19,146	6	160	764	19,399	6	162
Cadmium	22.7584	0	0	0	0	0	2	2	49
Calcium	0.000028	56,122	1,424,736	2	40	141,042	3,580,537	4	100
Chromium	0.075696709	0	0	0	0	16	393	1	30
Cobalt	0.114285714	0	0	0	0	2	60	0	7
Copper	0.623482222	0	0	0	0	24	609	15	380
Iron	0.0056	1,649	41,851	9	234	2,150	54,581	12	306
Lead	2.24	0	5	0	10	1	36	3	80
Magnesium	0.000865533	528	13,407	0	12	9,451	239,933	8	208
Manganese	0.102666667	2	51	0	5	32	806	3	83
Mercury	110.0327273	0	0	0	0	0	0	0	6
Molybdenum	0.201438849	0	0	0	0	30	755	6	152
Nickel	0.108914308	0	0	0	0	8	204	1	22
Selenium	1.121344	5	127	6	142	8	201	9	226
Silver	16.47072824		0		0				
Sodium	0.00000549	33,542	851,501	0	5	49,542	1,257,683	0	7
Thallium	2.854901961	0	0	0	0	5	114	13	326
Tin	0.301075269								
Titanium	0.029319372	386	9,788	11	287	403	10,218	12	300
Vanadium	0.28								
Zinc	0.046886								
Chloride	0.0000243	6,447	163,668	0	4	13,083	332,138	0	8
Sulfate	0.0000056	113,705	2,886,547	1	16	284,333	7,218,193	2	40
Nitrate/Nitrite	0.0032	2,274	57,741	7	185	1,370	34,779	4	111

		BA Close-Loop Water for 10% Purge Subtracting Source Water Median				BA Close-Loop Water for 10% Purge Not Subtracting Source Water Median			
Analyte	TWF	µg/L	lb/yr	TWF* µg/L	TWPE/yr	µg/L	lb/yr	TWF µg/L	TWPE/yr
Total Phosphorus	0								
Ammonia-N	0.00111								
Fluoride	0.035	184	4,677	6	164	349	8,853	12	310
Total Kjeldahl Nitrogen	0								
Biochemical Oxygen Demand	0								
Sulfide (as S)	2.801446667	25	623	69	1,746	31	790	87	2,214
Sulfite (as SO3)	0								
Cyanide	1.116923077	0	0	0	0	0	0	0	0
Total Dissolved Solids	0								
Total Suspended Solids	0								
Hexane Extractable Material	0								
Nitrogen, Total Organic (as N)	0.00228								
Oil and Grease	0								
Silica-Gel Treated Hexane Extractable Material	0								
Hexavalent Chromium	0.516557576								
Silica	0								
Yttrium	0								
Bromide	0	128	3,237	0	0	240	6,093	0	0
	Total	**219,692**	**5,577,192**	**366**	**9,300**	**507,031**	**12,871,685**	**462**	**11,724**

EPRI's single-pass bromide value taken from EPA's average bottom ash concentration value.
For results below the MDL, EPRI used 1/2 the method detection limit values. The incremental reduction is automatically set to zero if Effluent < Influent.
Data for BA Close-Loop Water for 10% Purge Subtracting Source Water based on EPRI 2016

Table H-4 (continued)
Bottom ash pollutant reduction estimate

		BA Close-Loop Water for 10% Purge Subtracting Source Water Mean				BA Close-Loop Water for 10% Purge Not Subtracting Source Water Mean			
Analyte	TWF	µg/L	lb/yr	TWF* µg/L	TWPE/yr	µg/L	lb/yr	TWF* µg/L	TWPE/yr
Aluminum	0.064691216	4,803	121,925	311	7,887	4,967	126,083	321	8,156
Antimony	0.01225	0	0	0	0	5	123	0	2
Arsenic	3.469333333	21	530	72	1,840	22	551	75	1,913
Barium	0.001990757	763	19,360	2	39	838	21,261	2	42
Beryllium	1.056603774	0	0	0	0	0	5	0	6
Boron	0.008341667	4,387	111,374	37	929	4,416	112,118	37	935
Cadmium	22.7584	0	1	1	32	0	3	3	66
Calcium	0.000028	126,569	3,213,130	4	90	199,527	5,065,257	6	142
Chromium	0.075696709	0	0	0	0	16	393	1	30
Cobalt	0.114285714	0	0	0	0	2	60	0	7
Copper	0.623482222	0	0	0	0	24	609	15	380
Iron	0.0056	2,009	50,999	11	286	2,516	63,872	14	358
Lead	2.24	0	5	0	10	1	36	3	80
Magnesium	0.000865533	3,029	76,896	3	67	27,031	686,211	23	594
Manganese	0.102666667	10	242	1	25	34	867	4	89
Mercury	110.0327273	0	0	0	5	0	0	0	11
Molybdenum	0.201438849	0	0	0	0	30	755	6	152
Nickel	0.108914308	0	0	0	0	8	204	1	22
Selenium	1.121344	7	174	8	195	8	210	9	236
Silver	16.47072824								
Sodium	0.00000549	85,812	2,178,467	0	12	100,847	2,560,151	1	14
Thallium	2.854901961	0	0	0	0	5	114	13	326
Tin	0.301075269								
Titanium	0.029319372	386	9,788	11	287	403	10,218	12	300
Vanadium	0.28								
Zinc	0.046886								
Chloride	0.0000243	13,276	337,033	0	8	31,076	788,895	1	19
Sulfate	0.0000056	475,292	12,065,939	3	68	587,616	14,917,432	3	84
Nitrate/Nitrite	0.0032	18,571	471,459	59	1,509	17,003	431,644	54	1,381

		BA Close-Loop Water for 10% Purge Subtracting Source Water Mean				BA Close-Loop Water for 10% Purge Not Subtracting Source Water Mean			
Analyte	TWF	µg/L	lb/yr	TWF* µg/L	TWPE/yr	µg/L	lb/yr	TWF* µg/L	TWPE/yr
Total Phosphorus	0								
Ammonia-N	0.00111								
Fluoride	0.035	329	8,341	11	292	493	12,515	17	438
Total Kjeldahl Nitrogen	0								
Biochemical Oxygen Demand	0								
Sulfide (as S)	2.801446667	87	2,200	243	6,163	93	2,367	261	6,631
Sulfite (as SO3)	0								
Cyanide	1.116923077	0	5	0	6	0	11	0	12
Total Dissolved Solids	0								
Total Suspended Solids	0								
Hexane Extractable Material	0								
Nitrogen, Total Organic (as N)	0.00228								
Oil and Grease	0								
Silica-Gel Treated Hexane Extractable Material	0								
Hexavalent Chromium	0.516557576								
Silica	0								
Yttrium	0								
Bromide	0	314	7,980	0	0	366	9,282	0	0
	Total	**735,664**	**18,675,847**	**778**	**19,748**	**977,345**	**24,811,250**	**883**	**22,425**

EPRI's single-pass bromide value taken from EPA's average bottom ash concentration value.
For results below the MDL, EPRI used 1/2 the method detection limit values. The incremental reduction is automatically set to zero if Effluent < Influent.
Data for BA Close-Loop Water for 10% Purge Subtracting Source Water based on EPRI 2016

2. Aluminum, antimony, arsenic, barium, beryllium, boron, cadmium, calcium, chromium, hexavalent chromium, cobalt, copper, iron, lead, magnesium, manganese, mercury, molybdenum, nickel, selenium, silica, silver, sodium, thallium, tin, titanium, vanadium, yttrium, and zinc

20 <u>BATW – Data</u>

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 52

Comment Excerpt:

7.1.3 EPA's BATW mass loading evaluation is based on inadequate analytical data.

EPA estimated bromide mass loadings from BATW to surface water based on analytical data from samples obtained during EPA site visits and data provided to EPA by utilities and industry groups. After excluding most of the available data based on a set of quality criteria [ERG, 2019b], EPA based the BATW mass loadings on bromide concentrations in 10 samples from four power plants. The average bromide concentrations in BATW at these four facilities ranged from < 1 mg/L to 14 mg/L [EPA, 2019c]. EPA averaged the mean concentrations at each plant and substituted one half the detection limit for one non-detect value to obtain the concentration of 5.1 mg/L used in the BATW analysis. Given the high variability among this small set of sites, and the fact that two of the four units are retired or are dry ash handling facilities, it is questionable whether these data are representative of BATW effluent concentrations across the power industry.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 87

Comment Excerpt:

6. EPA Used Questionable Analytical Data to Estimate Bromide Loadings From BATW.

The concentration data used to develop EPA's average bromide concentration relative to BATW are available, and a review of them indicate they are not a sufficient analytical base for characterizing bromide in BATW. As EPRI details, EPA estimated nationwide bromide loadings to surface waters based on 10 samples from four power plants.[159] This very small data set had a wide range of variability, from less than 1 mg/L to 14 mg/L. Additionally, two of the four plants have either retired or retrofitted dry ash handling. UWAG finds this data set inadequate for estimating the bromide contribution from BATW.

[159] EPRI 2020 Comments at 7-2.

21 BATW – High Recycle Rate

No comment excerpts were received on this topic.

21a BATW – High Recycle Rate – Purge Basis, Provisions, and Regulatory Language

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 2

Comment Excerpt:

- EPA has recognized the importance of a limited purge stream for BATW high recycle rate systems, such as remote mechanical drag chain systems and dewatering bin systems.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 5

Comment Excerpt:

As to BATW, EPA proposes a purge allowance not to exceed 10 percent per day of the "primary active wetted bottom ash system volume" of a high recycle system, applied on a 30-day rolling average. EPA would condition any purge on four criteria related to precipitation inflows, chemical imbalances, water imbalances, and maintenance activities. Proposed §§ 423.13(k)(2)(i)(A)(1), (2), (3), (4). UWAG recommends that EPA create a separate exemption for precipitation inflows to high recycle systems, due to the inherent variability of storm events. Including storm water inflows as part of the 10 percent by volume purge allowance introduces too much uncertainty due to the variability of storms and the difficulties of predicting storm movement and intensity. Additionally, EPA should base the storm water event purge condition on a 10-year, 24-hour storm event rather than a 25-year, 24-hour storm event. Otherwise, facility owners will need to design their remote mechanical drag chain systems or dewatering bin systems to hold an accumulation of storm water up to the 25-year, 24-hour storm event threshold, which will add significant costs—for which EPA apparently did not account—to the system. Also, EPA should clarify the other three purge criteria (Proposed §§ 423.13(k)(2)(i)(A)(2)-(4)) to remove any references to additional installed spares, redundancies, equipment, or components. The inclusion of this language creates ambiguity about what is required by the rule, when EPA has clearly outlined the components of model BATW technologies, and that determination is controlling. EPA also should replace the "additional control measures" provisions applicable to BATW (Proposed § 423.13(k)(2)(i)(B)) with a more workable "best management practices" plan approach, as further described in these comments.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)

Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 16

Comment Excerpt:

II. EPA's Proposed 10 Percent By Volume Discharge Allowance for BATW Recirculating Systems is an Appropriate Adjustment to the 2015 Rule.

UWAG supports EPA's proposal to allow a 10 percent by volume 30-day rolling discharge allowance from recirculating BATW systems, while recommending some adjustments to clarify the proposal. The ability to blow down a small sidestream from BATW recirculating systems under certain limited conditions will enable facilities to operate their BATW systems in ways that avoid excessive corrosion, scaling, and premature failure of equipment and increase system reliability, including the energy efficiency of the unit as a whole. This proposal would improve the longevity of recirculating systems (and thus their overall feasibility), while greatly reducing pollutant loadings.

A. Computation of the 30-Day Rolling Average Discharge Allowance is Straightforward.

EPA has proposed that facilities with bottom ash handling systems that largely recirculate BATW be allowed to discharge a 30-day rolling average of 10 percent of the system's "primary active wetted bottom ash system volume." Proposed § 423.13(k)(2)(i)(B). This is a much needed change from the 2015 rule.[2]

We provide a hypothetical example of how the 30-day rolling average discharge allowance would work in practice. Assume a remote mechanical drag chain ("RMDS") recirculating system with a trough holding a drag chain and associated pipes, a hopper, and a surge tank.[3] The following table provides hypothetical maximum volumetric capacity of each primary part of the system, excluding any installed spares, redundancies, maintenance tanks, or other secondary bottom ash system equipment. With a total volume of 300,000 gallons, 10 percent of the "primary active wetted bottom ash system volume" would be 30,000 gallons per day ("GPD").

Equipment	**Volume (gal.)**
RMDS Trough	250,000
1500' of 12" diameter pipe	10,000
Hopper	20,000
Surge Tank	20,000
TOTAL	300,000
10 Percent by Volume Blowdown	30,000

In addition to a "not to exceed" cap of 10 percent of the primary active wetted bottom ash system volume, the BATW purge will be limited by other conditions within the Proposed Rule. For instance, operators will only be allowed to purge under certain conditions related to maintenance, precipitation-related inflows, and water and chemistry imbalances within the system. Proposed §

423.13(k)(2)(i)(A). EPA also proposes additional control measures, including best management practices ("BMPs"). Proposed § 423.13(k)(2)(i)(B). In short, setting a "not to exceed" volumetric cap does not mean systems will always discharge up to the cap. The conditions under which a discharge may occur from a high recycle rate system would be strictly limited. The two following hypotheticals represent different operating scenarios in which purges would occur. Hypothetical 1 shows normal operations with minimal purges until the 24th day, when a maintenance event necessitates draining of the RMDS trough. Hypothetical 2 shows irregular discharges that could result from several physical and/or chemical imbalances within the system occurring during a single 30-day period.

Day	Hypothetical 1	Hypothetical 2
1	0	0
2	0	0
3	5,000	0
4	0	0
5	0	0
6	0	10,000
7	0	0
8	0	0
9	3,000	0
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	0	10,000
17	0	0
18	0	50,000
19	0	0
20	0	0
21	0	0
22	0	0
23	0	0
24	250,000	0
25	0	0
26	0	0
27	0	0
28	0	0
29	0	50,000
30	0	30,000
TOTAL	258,000	150,000
30 Day Average	8,600	5,000

The operator would (1) provide its calculation of the 10 percent primary active wetted system volume to the permitting authority; (2) keep a record of all purge discharges, noting their total volume and the reason for the purge; and (3) calculate the 30-day rolling average on a daily basis. These records would be subject to inspection by the permitting authority.

For a dewatering bin system, the method of calculating the 10 percent by volume purge would be very similar. In the following hypothetical, the dewatering bin receives the BATW, where the majority of the ash is removed. The sumps catch the decanted water and return it to the process. The BATW flows to a primary settling tank and then to a secondary settling tank. The water in the secondary settling tank is recycled back to the boiler or process. With a total volume of 622,000 gallons, 10 percent of the "primary active wetted bottom ash system volume" would be 62,200 GPD.[4]

Equipment[5]	**Volume (gal.)**
Dewatering Bin	190,000
Settling Tank 1	280,000
Settling Tank 2	120,000
1500' of 12" diameter pipe	10,000
Hopper	20,000
Sumps (2)	2,000
TOTAL	622,000
10 Percent by Volume Blowdown	62,200

This method of determining the 10 percent purge volume is relatively easy to calculate, can be evaluated by the permitting authority, and provides certainty to the permittee of the level of discharge allowed, while the conditions under which purges are allowed effectively cap the level of discharge.

[2] In the 2015 rule, EPA concluded that some, but not all, units could use mechanical drag chains (which do not require water to transport bottom ash). Final Rule - Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,838, 67,852 n.24 (Nov. 3, 2015) ("2015 rule"); EPA, *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA-821-R15-007, EPA-HQ-OW-2009-0819-6432 (Sept. 2015) ("2015 TDD") at 7-41, 9-5 – 9-6 EPA concluded that units that could not use mechanical drag chains could use remote mechanical drag chains or other technology that used, but recycled transport water, which it assumed would not need to discharge except in extremely limited circumstances. It therefore set a near-zero discharge standard (40 C.F.R. § 423.13(k)(1)(i)) with very limited exceptions for low volume, short duration discharges of wastewater from minor leaks or minor maintenance events. See 40 C.F.R. § 423.11(p). EPA did not allow any discharges associated with major maintenance events or storm events. The only other means of discharging BATW under the 2015 rule would be to introduce it into the FGD scrubber as make-up water. 40 C.F.R. § 423.13(k)(1)(i). However, in many circumstances, it is not feasible to send BATW to the scrubber. *See infra* at Section V.

[3] Other BATW system configurations may have more components that are part of the primary system and, thus, should be included when computing the volume of the primary active wetted bottom ash system. The example represents just one possible configuration.

[4] As with the RMDS hypothetical, other dewatering bin systems may have more or different components that are part of the primary active wetted bottom ash system volume. The example represents just one possible configuration.
[5] While EPA's Supplemental Technical Development Document focuses on the components of an RMDS system, dewatering bin systems can also be operated as high recycle rate systems. *Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA-821-R-19-009, EPAHQ-OW-2009-0819-8211 (Nov. 2019) ("Supplemental TDD"). In the 2015 TDD, EPA describes a dewatering bin system as generally consisting of two dewatering bins with multiple settling tanks. 2015 TDD at 7-40. Piping, pumps, and sumps are also normal components of dewatering bin systems. However, the "primary active wetted bottom ash system volume" for dewatering bin systems would include the volume of only one of the two dewatering bins because, "while one bin fills, the other is dewatered and the ash is unloaded into trucks or rail cars." *Id.* at 7-40.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 17

Comment Excerpt:

B. A 10 Percent By Volume Discharge Allowance is Appropriate Based on Operating Histories for Partially Closed-Loop Bottom Ash Systems

A 10 percent by volume discharge allowance would enable RMDSs, dewatering bin systems, and similar BATW systems to operate more consistently and without excessive corrosion, scaling, or other operational issues. In 2017-2018, the Electric Power Research Institute ("EPRI") studied the management of purges from partially closed-loop BATW systems. *Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges*, EPA-HQOW-2009-0819-7346 (Sept. 2018). The study documented a variety of reasons why operators purge their systems of some portion of BATW, including:

- water imbalances due to excess water entering the system, including storm events;
- purges to maintain water quality, including those related to acidity and corrosiveness; scaling; and abrading of equipment due to solids carryover from the ash-settling device;
- purges due to maintenance events; and
- leaks or line ruptures.

Id., Table 1-1 at 1-4 – 1-6.

For example, one facility purged to avoid corrosive conditions due to low pH water in the bottom ash hopper overflow. [6] *Id.* at 1-1. Another facility purged to avoid corrosive conditions caused by cycling up the make-up water supply's salts. *Id*. Other purges were due to maintenance events, such as draining the RMDS to repair the drag chain, or draining for scheduled inspections or other maintenance. *Id*. Based on its study of seven facilities with partially closed-loop RMDSs or dewatering bin systems, the largest single type of purge event at each plant ranged from 1-5 percent of the system volume (including surge tanks) if averaged over 30 days. *Id.*, Table 1-2, at 1-8 – 1-12, 1-17.[7] Updated research in this area by EPRI showed that, out of 22 plants with high recycle rate BATW systems, nearly all had a purge that ranged up to nearly 10 percent of the system volume per day.[8] EPRI Comments on Proposed Rule – Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Jan. 20, 2019) ("EPRI 2020 Comments") at 8-1.

Given EPRI's findings, it is appropriate for EPA to set a 10 percent by volume discharge allowance. EPRI's sample size is small in relation to the hundreds of plants subject to BATW limitations under the rule. Therefore, the sample size likely does not account for the range of purge rates within the industry. Also, it is possible that multiple events at a single facility would occur at the same time, increasing the necessary purge rate. For example, a water imbalance could occur shortly before the time scheduled for a maintenance outage. If the purge necessary to correct the imbalance was averaged into the same 30-day period as the purge needed for maintenance purposes, the percentage of purge in relation to system volume might exceed 5 percent. Finally, the industry has limited experience managing BATW closed-loop systems, and setting the allowed purge rate at 10 percent of the system volume per day averaged over a rolling 30-day period provides some operational flexibility, while maintaining the great majority of the environmental benefits attributable to BATW reductions from the 2015 ELGs.

[6] The purged water would have been treated before discharge to meet the pH standards applicable to all steam electric discharges. 40 C.F.R. § 423.12(b)(1).
[7] EPRI also explains the problems associated with other possible means of regulating BATW system purges, such as setting allowable purges based on water quality (*Id.* at 1-18 – 1-20) and setting allowed purges based on planned outage frequencies (*Id.* at 1-17 – 1-18).
[8] EPRI also documents a plant which purged roughly 11 percent of system volume per day on average, due to buildup of corrosive salts. EPRI 2020 Comments at 8-1.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 18

Comment Excerpt:

C. The Criteria for BATW Purging Should be Amended.

EPA proposes four conditions under which it would allow the discharge of BATW purge, generally described as follows:

- maintenance of system water balance due to certain precipitation-related inflows;
- maintenance of water balance when regular inflows from wastestreams other than BATW exceed the ability of the system to accept recycled water;
- performance of certain maintenance activities; and
- maintenance of system water chemistry when the facility is unable to manage pH, corrosive compounds, and fine particulates.

Proposed § 423.13(k)(2)(i)(A)(1-4).

All of these categories are necessary reasons for purging recirculating BATW systems.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 19

Comment Excerpt:

1. Discharges Due to Precipitation Events Should Not Count Against the 10 Percent By Volume Discharge Allowance.

Under the Proposed Rule, BATW purges would be allowed for storm events according to the following condition:

To maintain system water balance when precipitation-related inflows within any 24-hour period resulting from a 25-year, 24-hour storm event, or multiple consecutive events cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment.

Proposed § 423.13(k)(2)(i)(A)(1).

These precipitation-related purges—along with the other three categories of discharge related to water imbalance due to regular inflows, maintenance issues, and water chemistry imbalances—would have to fit within the 10 percent by volume rolling 30-day average purge allowance. In other words, during the same 30-day period, if a facility experienced a major maintenance event and had to drain the system, had water chemistry imbalances, and had to manage precipitation related inflows from a major storm event, the facility would be challenged to meet the 10 percent volumetric cap.

Including precipitation events within the 10 percent by volume discharge allowance is problematic because it creates great uncertainty for the operator. Operators can do their best to estimate probable rainfall over a 30-day period, but often weather predictions are wrong or simply inadequate to judge the actual intensity, precise location of the storm (e.g., hurricanes), or return frequency.

In the case of Hurricane Florence, which battered North and South Carolina in September 2018, forecasters were generally correct about the path of the hurricane, but failed to predict that it would move very slowly (2-3 mph) once it hit landfall.[9] The storm's slow progress on land meant that it dumped heavy amounts of precipitation along the coast and inland, averaging between 20-30 inches.[10] Combined with a strong storm surge, the heavy precipitation caused extensive flooding.

Another storm system stalled over the Tennessee Valley in February 2019 causing a long period of heavy rain and flooding.[11] The storm set new rainfall records for the month of February,[12] affecting utilities in Kentucky, Arkansas, and Illinois. The combined rainfall was over 12 inches at multiple sites over the month but did not reach the 25-year, 24-hour storm event threshold. By the end of the month, nearly the entire state of Tennessee had received between 10 and 20 inches of rain.

Also, the variability of storm events across the country means that the utility of the 10 percent by volume purge will be reduced in areas subject to very large storm events. Plants in heavy rainfall areas will be penalized, as they will have to reduce their purges to account for greater amounts of precipitation inflows.

To illustrate the variability in flows for precipitation events, our engineer estimated the amount of rainfall that would fall on an RMDS installation for a 10-year, 24-hour storm and a 25-year, 24-hour storm. He further assumed three different geographical locations for the RMDS, with varying climates. He used the following formula to calculate water accumulation:

$$Volume\ (gal.) = Rainfall\ (in.) \times \frac{1\ ft.}{12\ in.} \times Area\ (ft^2) \times Permeability \times \frac{7.481\ gal.}{1\ ft^3}$$

To estimate the rainfall for each level of storm, he used standard values presented in the National Weather Service's Technical Paper No. 40. [13] The rainfall levels for the three geographical locations are presented in the table below.

Rainfall Event	Point Marion, PA	Axis, AL	Kirtland, N.M.
10-year, 24-hour storm	3.43 in.	8.37 in.	1.55 in.
25-year, 24-hour storm	4.03 in.	10.5 in.	1.87 in.

To estimate the size of an RMDS system, the engineer computed the area of a constructed RMDS consisting of three troughs using data from Google Earth. The RMDS system area was found to be approximately 42,800 square feet.[14] The plant configuration also included additional open-top clarifiers. The area of the clarifiers is another 25,500 square feet.[15] As to permeability, the engineer assumed the permeability and time of concentration were equal to 1. In other words, the model assumes all the water that falls on the area makes its way into the system near instantaneously.

The resulting rainfall amounts for the three locations are as follows:[16]

Rainfall Event	Point Marion, PA	Axis, AL	Kirtland, NM
10-year, 24-hour storm RMDS area only (gals.)	91,520	223,330	41,360
25-year, 24-hour storm RMDS area only (gals.)	107,530	280,160	49,900
Percentage Increase, from 10-year storm to 25-year storm capacity	17.5%	25.4%	20.7%
10-year, 24-hour storm RMDS and clarifier area (gals.)	146,050	356,390	66,000
25-year, 24-hour storm RMDS and clarifier area (gals.)	171,590	447,080	79,620
Percentage Increase, from 10-year storm to 25-year storm capacity	17.5%	25.4%	20.7%

For an identical RMDS system, therefore, the storm water containment requirements are quite different, depending on geographic location. An engineer in Axis, Alabama, needing to contain all storm water that would fall on the RMDS and its clarifiers up to the 25-year, 24-hour storm event threshold proposed by EPA would likely plan for an additional 500,000 gallons of capacity, just for storm water. This is more than 6 times the capacity needed for the same size storm for an identical RMDS in Kirtland, New Mexico. The percentage increase in storm volume between a 10-year, 24-hour storm and a 25-year, 24-hour storm ranges from approximately 18 percent to 25 percent for these three locations, and these locations undoubtedly do not capture the full range of variability across the country.

This illustration demonstrates the following points. First, precipitation inflows to RMDSs vary greatly. This is why including precipitation inflows as part of the 10 percent by volume discharge allowance is problematic. Second, sizing up the RMDS to accommodate a 25- year, 24-hour storm rather than a 10-year, 24-hour storm is a significant increase in capacity and therefore in costs.

The benefit of a discharge allowance is in the certainty of being able to discharge a set amount. This certainty allows engineers to design, and operators to operate, a system that accounts for the discharge allowance. If the facility has to account for the possibility of reaching the discharge limit due to unpredictable precipitation inflows, then the design engineer will need to increase the capacity of the system to ensure against “worst case” situations. This increase in capacity of the system could result in tens of millions of dollars in additional costs.

For all these reasons, the Proposed Rule should establish a separate discharge exemption solely for inflows related to precipitation events

[9] Willie Drye, *“What Forecasters Got Right and Wrong about Florence,” National Geographic,* https://www.nationalgeographic.com/environment/2018/hurricane-florence-forecasting-science/ (last visited on Dec. 11, 2019).

[10] National Weather Service, *Historic Hurricane Florence, September 12-15, 2018,* https://www.weather.gov/mhx/Florence2018 (last visited on Dec. 11, 2019).
[11] National Weather Service, *Late February 2019 Historic Rainfall and Widespread Flooding,* https://www.weather.gov/ohx/lateFebruary2019flooding (last visited on Jan. 20, 2020).
[12] *Id.*
[13] Technical Paper No. 40, *Rainfall Frequency Atlas of the United States for Durations from 30 Minutes to 24 Hours and Return Periods from 1 to 100 years*, https://hdsc.nws.noaa.gov/hdsc/pfds/index.html (May 1962, reprinted 1963).
[14] Enclosing an RMDS to eliminate precipitation inflows is impractical and adds significant costs. In the 2015 rule, EPA estimated buildings for RMDSs to be located in climates with a mean daily minimum temperature of 32°F using a cost factor of 18.75 percent of the purchased equipment costs. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments* ("2015 Response to Comments"), EPA-HQ-OW2009-0819-6469-Att5 (Sept.2015) at 6-545. Because RMDSs contain heated water, an enclosed RMDS likely would require an enhanced ventilation system to reduce condensation on walls and other surfaces, which could cause excess corrosion and potential safety issues with limited visibility. The actual building costs are likely more than what is represented by EPA's cost factor.
[15] The computed square footage only include the immediate area surrounding the open top systems. Plant environmental specialists may require storm water from additional areas to also be captured so as to contain any spills or leaks of process water in the case of an unexpected event, such as a pipe break.
[16] In a recent communication, EPA staff indicated that, in the Agency's opinion, a "properly designed" RMDS would not receive much storm water. But where an RMDS is not covered, the RMDS trough or troughs and any clarifiers are open to the elements and would regularly receive storm water. The computations provided here demonstrate that significant rainfall amounts from a major storm event would enter the RMDS system.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 20

Comment Excerpt:

2. The Precipitation Event Condition Should be Based on the 10-Year, 24-Hour Storm Event and Should Not Mandate Additional Equipment Beyond the Model Technology.

The Proposed Rule would allow storm event purge discharges "when precipitation related inflows within any 24-hour period resulting from a 25-year, 24-hour storm event, or multiple consecutive events cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment." Proposed § 423.13(k)(2)(i)(A)(1). UWAG recommends that this provision be amended to read as follows (changes in bold):

The discharge of pollutants in bottom ash transport water from a properly installed, operated, and maintained bottom ash system is authorized under the following conditions: to maintain system water balance when precipitation related inflows are associated **with a 10-year, 24-hour or greater storm event, or an extended rainfall event or events within a rolling 7-day period, that cumulatively are equivalent to, or greater than, the 10-year, 24-hour storm event.**

The 10-year, 24-hour storm event is a more appropriate threshold than the 25-year, 24- hour storm event because it is a well-defined metric and already in use for the management of coal pile runoff within the steam electric industry. Any untreated overflow of coal pile runoff from a system designed, constructed, and operated to treat the volume of coal pile runoff associated with a 10-year, 24-hour storm event is not subject to the coal pile runoff limits. 40 C.F.R. § 423.12(b)(10).[17]

If the discharge threshold remains at the proposed 25-year, 24-hour storm event, then recirculating BATW systems will need to be designed or re-designed to hold the estimated amount of at least a 25-year, 24- hour storm event which will increase the size and cost of the systems.[18]

Also, EPA's proposed language meant to allow precipitation discharges associated with "multiple, consecutive [storm] events" should be clarified. Extended storms that do not exceed the 10-year, 24-hour storm event can cause major operational issues. For instance, in four months of 2018, a Texas facility received 43.55 inches of rain, with no single day exceeding the 10-year, 24-hour storm event threshold. The cumulative rain, however, was more than 23 inches above normal. The proposed language change to reference "an extended rainfall event or events within a rolling 7-day period that cumulatively are equivalent to, or greater than, the 10-year, 24-hour storm event" solves the problem of a period of very heavy rains that does not on any one day exceed the 10-year, 24-hour threshold.

Finally, the condition's reference to "installed spares, redundancies, maintenance tanks and other secondary bottom ash system equipment" is confusing. EPA has not included installed spares, redundancies, maintenance tanks, or other secondary equipment in the model BATW recirculation technology, an RMDS.[19] Therefore, UWAG recommends that references to these additional components be removed. The rule should be clear that purchase and installation of additional components is not mandated or recommended to manage storm events.

EPA may be concerned that facilities that have installed spares or redundancies would choose not to use these portions of their systems, if the final rule allows a 10 percent by volume purge. This concern is unwarranted. The anti-bypass provisions of the NPDES regulations prohibit any bypassing of existing equipment. EPA defines "bypass" as "the intentional diversion of waste streams from any portion of a treatment facility." 40 C.F.R. § 122.41(m)(1)(i). Bypasses are expressly prohibited except in very limited circumstances, and the rule requires use of "auxiliary treatment facilities." *Id.* at § 122.41(m)(4)(B). In fact, the rule is quite clear that existing equipment and proper operational procedures must be used to avoid bypasses:

Bypass is prohibited, and the Director may take enforcement action against a permittee for bypass, unless:

…

(B) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime.

Id. at § 122.41(m)(4)(B).

Based on its standard bypass regulations, EPA has already ensured proper use of any existing spares, redundancies, or other secondary equipment. The changes to the criterion that UWAG recommends properly limit purges to those necessary to maintain water balance in light of major storms.

[17] Current § 423.11(i) defines the 10-year, 24-hour storm as "a rainfall event with a probable recurrence interval of once in ten years as defined by the National Weather Service in Technical Paper No. 40. *Rainfall Frequency Atlas of the United States,* May 1961 or equivalent regional rainfall probability information developed therefrom." Whatever storm event EPA ultimately chooses, it should follow the same practice and define the term consistent with the National Weather Service's 1961 Technical Paper, which is the standard reference point for engineering design.
[18] It is not clear from the record whether EPA's estimated costs for BATW high recycle rate systems reflect sizing of all components to contain precipitation inflows for all storms up to the 25-year, 24-hour storm event.
[19] EPA lists the following as comprising the model technology: "rMDS (away from the boiler). Sump. Recycle pumps. Chemical feed system. Semi-dry silo." Supplemental TDD at 5-33.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 21

Comment Excerpt:

3. The Second Water Balance Condition Should Also be Amended.

EPA's second BATW purge condition, dealing with water imbalances caused by regular inflows, also should be amended to improve its clarity. The provision reads as follows:

The discharge of pollutants in bottom ash transport water from a properly installed, operated, and maintained bottom ash system is authorized under the following conditions:

…

(2) To maintain water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is not feasible….

Proposed § 423.13(k)(2)(i)(A)(2).

This provision would require the permit writer to determine when it is "not feasible" to segregate certain wastestreams from BATW and, therefore when water balances may be exceeded based on regular inflows. Not only does this complicate the permitting process, it leaves the permit writer without any guidelines for what wastestreams are or are not feasible to segregate, especially for existing treatment systems. [20] UWAG recommends replacing this provision with the following: "(2) to maintain water balance consistent with system design." This provision would prevent extraneous additions of wastestreams to the BATW system because the system design and flow will be specified in the permit application. The permit writer has the ability to examine inflows to the BATW system as a part of reviewing the permit application and can ask any additional questions about segregating out other wastestreams that he or she deems appropriate. But so long as the regular inflows are consistent with the specified system design, the permittee would have the assurance that it could discharge up to the 10 percent by volume allowance in the limited circumstances under which purges are allowed.

[20] In some cases, boiler seal trough water may be hard to segregate. Boiler backpass wash water may also be hard to segregate because of the area of use and the difficulty of re-piping. However, a permit writer should not be required to make these engineering determinations.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 22

Comment Excerpt:

4. The Third Condition on Maintenance Discharges Contains Unwarranted Language Regarding Additional Equipment.

The BATW purge condition for maintenance reasons also should be amended. It provides:

The discharge of pollutants in bottom ash transport water from a properly installed, operated, and maintained bottom ash system is authorized under the following conditions:

…

(3) To conduct maintenance not otherwise exempted from the definition of transport water in § 423.11(p) when water volumes cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment.

Proposed § 423.13(k)(2)(i)(A)(3).

As with the precipitation-related condition, this condition mentions additional equipment beyond what EPA has included in the model RMDS technology, potentially creating confusion about what types of equipment constitute the model technology and how a permit writer should interpret the condition. UWAG recommends that the condition be simplified to read: "(3) to conduct maintenance not otherwise exempted from the definition of transport water in § 423.11(p)." This is a straightforward provision only exempting maintenance-related purges. The permittee could be required to note in the discharge log the type of maintenance being performed. And, as mentioned previously, any system that already has installed spares or redundancies would be obligated by the NPDES bypass rules to continue to operate the system in a manner consistent with its permit and permit application. *See supra* at Section II.C.2

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 23

Comment Excerpt:

5. The Fourth Condition on Water Chemistry Imbalances Also Should be Amended.

The proposed purge condition for water chemistry imbalances provides:

The discharge of pollutants in bottom ash transport water from a properly installed, operated, and maintained bottom ash system is authorized under the following conditions:

…

(4) To maintain system water chemistry where installed equipment at the facility is unable to manage pH, corrosive compounds, and fine particulates to below levels which impact system operations.

Proposed § 423.13(k)(2)(i)(A)(4).

UWAG recommends three clarifications for this provision. First, scaling should be added to the list of chemistry-related operational problems because scaling can lead to equipment/system failures.[21]

Second, “corrosive substances” would be better than “corrosive compounds” to avoid confusion over whether corrosives that are not compounds are covered under the provision. The intent appears to be to cover all types of corrosives, whether they are compounds or not. Therefore, “corrosive substances” is a better catch-all term.

Third, this provision mentions “installed equipment” just as two of the other conditions refer to “installed spares” and “redundancies.” As with the other conditions, including the wording “installed equipment” in this condition creates confusion as to whether additional equipment beyond the model technology is required. It is also unwarranted because, as previously discussed, the NPDES bypass rules ensure appropriate use of all installed equipment. Also, excess fines, corrosion, scaling, and other problems associated with water chemistry imbalances are likely to affect system operations and require system maintenance. UWAG recommends broadening the language to include chemistry imbalances that impact maintenance as well as those that impact operations. Taking into account all these issues, UWAG recommends the following wording:

(4) To maintain system water chemistry when the system is unable to manage pH, corrosive **substances, substances or conditions causing scaling, and/or** fine particulates to below levels which impact system operations **or maintenance**.

[21] EPRI, *Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges,* EPA-HQ-OW-2009-0819-7346, at 1-2 (Sept. 2018).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 24

Comment Excerpt:

D. EPA Should Clarify the Additional Control Measures Provision.

In addition to the four BATW purge conditions discussed above, the Proposed Rule would require that all discharges of BATW be "reduced or eliminated to the extent achievable using control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice, and in no instance shall it exceed a 30-day rolling average of ten percent of the primary active wetted bottom ash system volume." Proposed § 423.13 (k)(2)(i)(B).

This provision is very vague and has the potential to slow down the permitting process. It would require permit writers to make judgments about whether BATW discharge reductions are "achievable" using unspecified "control measures" that would include unspecified "best management practices" that must be "technologically available and economically achievable" based on "best industry practice." Each term is subject to interpretation, and—taken together—they amount to having permit writers conduct another effluent guidelines rulemaking. They must (1) assess what "control measures" may be applicable to the facility's BATW system; (2) estimate the current BATW discharges; (3) study the plant's water balance to determine if there are operational measures that could reduce BATW discharges, taking into account site specific features and metallurgical issues; (4) assess any additional "control measures" and determine whether they are technologically available; (5) evaluate any candidate control measures in terms of economic achievability (presumably for the individual facility, not the industry as a whole, although the provision is not clear); and (6) compare the candidate technologies and their operations to "best industry practice." Then they must document their evaluations and decisions as part of the permit proceeding.

All of this analysis would be done to determine if the permittee could perhaps reduce the 10 percent by volume discharge by any amount at all, such as to 6 or 7 percent of the volume of the system. Given the burdens most permit writers carry, the backlog of permitting generally, and the need for prompt permit revisions for implementing the Proposed Rule, this seems to be a poor use of a valuable resource.

UWAG submits that a more straightforward approach is to apply a BMP requirement under which the permittee would conduct a one-time study to determine whether there are additional steps that could be undertaken to maximize recycling of BATW, consistent with use of the components of a model high recycle rate BATW system.[22] The one-time study would (1) identify system metallurgy and describe any limitations on recycling based on the existing metallurgy; (2) describe other limitations on recycling (*e.g.*, quality of intake water, problems with scaling, etc.); (3) describe any operational history relevant to the ability to recycle (*e.g.,* maintaining appropriate freeboard for storm events); and (4) describe and evaluate any potential means of additional recycling, including any operational means of reducing inflows to the system, and sending BATW to the FGD scrubber where piping to the scrubber already exists.

Based on this suggested BMP approach, UWAG recommends revising Proposed § 423.13(k)(2)(i)(B) so that it (1) sets a "not to exceed" cap on BATW purges of 10 percent of the primary active wetted bottom ash system volume for all discharges related to maintenance, water imbalances, or chemistry imbalances;[23] (2) require maintenance of a daily log of all BATW purges, and (3) require the permittee to conduct a one-time BMP study to evaluate whether the system is maximizing recycling, consistent with use of the applicable model technology. UWAG recommends that the one-time BMP study be submitted to the permitting authority within one year after the later of (1) commissioning of a high recycle rate BATW system or (2) the effective date of the permit. The permit would require the permittee to implement any feasible BMPs identified in the one-time study that are consistent with use of the model technology, following approval by the permitting authority.

[22] The components for an RMDS system, as described by EPA, are: an RMDS, a sump, recycle pumps, a chemical feed system, and a semi-dry silo. Supplemental TDD at 5-33. For a dewatering bin system, as EPA described it in the 2015 rule, the model technology would be two dewatering bins with two settling tanks and any associated sumps, piping and pumps.
[23] As described earlier, the rule should provide a storm event BATW purge allowance that is not included within the 10 percent by volume discharge cap.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 34

Comment Excerpt:

IV. Site-Specific Best Management Plans are Appropriate For Those Facilities Unable to Comply with a 10 percent by Volume Purge Allowance.

There likely will be a small fraction of facilities with CCR-compliant BATW handling systems that are unable to comply with a 10 percent by volume discharge allowance. In order to avoid premature closure of the affected units, the rule should contain a second option that would allow facilities that certify they cannot comply with the 10 percent by volume discharge allowance using their existing, CCR-compliant BATW handling system to minimize BATW purge to the extent practicable through a stringent BMP plan.[34]

In developing the plan, the permittee would submit information to its permit writer regarding the following criteria, explaining how each criterion affects the ability to recirculate or limit the amount of BATW:

- pH control, as well as control of corrosives (e.g., chlorides), scalants, etc.;
- materials of construction of BATW handling components;
- age and condition of system;
- historical maintenance requirements;
- data regarding fines build-up and coal quality;
- influent water quality (e.g., brackish water); and
- possible reuses of BATW within the facility

The permittee also would outline all measures taken and to be taken to minimize BATW purge, including reasonable efforts to segregate other wastewater streams from the BATW system, and include a detailed diagram of the system, including volumes of all components. The permittee would describe historical operation and maintenance ("O&M") requirements, including all maintenance events likely to require a discharge.

Based on this information and any other information the permit writer deems applicable, the resulting BMP plan would limit the system's purge to a level consistent with the level of recirculation the existing BATW system is capable of achieving. The BATW system operating under a site-specific BMP plan would be able to discharge volumes attributable to storm events equal to or larger than the 10-year, 24-hour storm event. The BMP would address discharges related to maintenance events and those necessary to maintain system water chemistry and water balance.

UWAG anticipates that a very small fraction of facilities would qualify for the site specific BMP approach, considering that most facilities are replacing their CCR surface impoundments with recirculating BATW systems and all of those systems (such as remote mechanical drag chain systems or dewatering bin systems) would be subject to the 10 percent by volume discharge allowance. There are, however, a few CCR-compliant facilities that do not have recirculating systems. For instance, Harrison Power Station uses cooling tower blowdown to sluice its bottom ash. This is environmentally beneficial because the cooling tower blowdown is reused and the facility does not draw up additional waters to use for sluicing. However, retrofitting recirculating BATW handling to meet a 10 percent by volume discharge standard so that the sluice water could be recirculated back to the cooling tower would entail a very significant retrofit to the cooling tower system as well as the BATW system. Furthermore, it is not technically feasible to recirculate cooling tower blowdown back to the cooling tower, since it was already purged to maintain the chemical balance of the cooling tower. The separation of systems would also require additional water withdrawals. In certain water-stressed regions of the country, it may be difficult to obtain approvals for increased water withdrawals for these sorts of retrofits.

[34] For example, some facilities have CCR-compliant surface impoundments that recycle BATW in a nearly closed-loop system. One UWAG member reports that its surface impoundment which receives BATW has a composite liner that meets the requirements of the CCR rule under 40 C.F.R § 257.70 (c) and operates with limited discharges.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 44

Comment Excerpt:

Based on these analyses, EPA has more than enough information to conclude that high recycle rate BATW systems, as a part of the overall rule, are economically achievable and reasonable.[58]

[58] While UWAG's proposed modifications to the rule may make some differences in pollutant removals, those differences are not likely to be significant.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 11

Comment Excerpt:

The purge capabilities allowed by the revised ELG would provide operational flexibility, while still providing a large majority of the pollutant reduction that would have been achieved by the 2015 ELGs.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 55

Comment Excerpt:

8. B**OTTOM ASH PURGE ALLOWANCE**

8.1 **The blowdown purge allowed by the 2019 proposed ELG BAT for BATW provides facilities operational flexibility, while still providing the majority of pollutant reduction that would have been achieved by the 2015 ELG Rule.**

In recent EPRI reports on bottom ash transport water, 22 plants with high-recycle rate bottom ash systems were interviewed [EPRI, 2019a; EPRI, 2019b]. Nearly all had a blowdown purge, which ranged up to near the ten percent of the system volume on a 30-day rolling daily average. The need to purge the system is driven by water imbalances from excess water entering the system (e.g., storm events), maintenance related activities, and maintaining water chemistry necessary for operations. Approximately half the plants surveyed observed acidity in the recirculated system originating from the seal water or cooling water in the hopper overflow that commingles with transport water. This water is difficult to segregate from recirculation systems because of its water contributions during sluicing and maintenance or leaks generally end up in the same area sumps as transport water. Levels of acidity coincide with increases in sulfates; this increase has resulted in calcium sulfate scaling in at least one system. A combination of chemical treatment and purging is often required to avoid corrosive or scaling conditions. Small fine solids can also accumulate in the water over time, accumulating and plugging parts of the system; a purge is also beneficial to remove these solids.

The operational flexibility of allowing for a ten percent purge maximum of 10% by volume discharge greatly benefits plants; however, some plants will have challenges achieving a purge of only ten percent. One plant purged roughly 11 percent of system volume per day on average due to buildup of corrosive salts when using lake water as makeup to the ash system. In fact, this purge volume was an order of magnitude higher when the plant changed from lake water supply to cooling tower blowdown for the bottom ash system makeup water [EPRI, 2018; EPRI, 2019a]. Due to storm events entering the high-recycle rate bottom ash transport water system, sites may be required to purge more than 10 percent per day over a 30-day period when large or continuous storms come within the same 30-day period. Often the exact quantity required for discharge cannot be known until the system has operated for an extended time.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 6

Comment Excerpt:

First, EPA should finalize the revised BAT limits for BATW and also include necessary compliance flexibilities. EPA appropriately proposes to update the BAT limits for BATW based on high recycle rate systems as the model technology. EPA rightly recognizes that wet bottom ash handling systems require some discharges of recirculating water for the purpose of managing overall system chemistry, and should therefore finalize needed compliance flexibilities like rolling average provisions, blowdown allowances and an allowance for additional discharges where necessary to account for large scale natural disasters that bring heavy and prolonged precipitation.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 12

Comment Excerpt:

EPA proposes to update the Best Available Technology (BAT) limits for BATW based on high recycle rate systems as the model technology. EPA rightly recognizes that wet bottom ash handling systems require discharges of recirculating water for the purpose of managing overall system chemistry. 84 Fed. Reg. at 64,634. These discharges, known as "blowdown," are necessary to prevent water imbalances that can lead to serious operational concerns in completely closed-loop wet bottom ash handling systems such as scaling and corrosion.[11] EPA states that new information available since it finalized the 2015 ELG Rule "indicates that some facilities with wet ash removal systems generally operate as zero discharge systems, but in many cases must operate as high recycle rate systems," and that EPA proposes to base the BATW BAT limitations on the "use of dry handling or high recycle rate systems rather than dry handling or closed-loop systems, the technologies on which the zero discharge BAT limitation adopted in the 2015 rule were based." Id. at 64,635. EPA notes that it is giving "particular weight to the CWA Section 304(b) statutory factor of "process changes." [12] Id.

The Proposed ELG Rule authorizes unit operators to discharge up to 10 percent of the primary active wetted bottom ash volume over a 30-day rolling average. This flexibility recognizes the reality that a certain amount of water discharge on a periodic basis is necessary. By permitting necessary "blowdown," EEI's members can effectively and efficiently operate and maintain compliant BATW systems. Id. at 64,635. The proposed discharge exemption will also provide much needed operational flexibility to manage small storm events and major maintenance events. EPA should finalize the proposed discharge allowance for wet bottom ash handling systems based on the Agency's more robust "evaluation of complex scientific data within its technical expertise" and the "process changes" described by the agency, as noted supra. [13]

An example highlights why permitting limited, but necessary blowdown is both reasonable and necessary to avoid serious operational issues. Duke Energy has a facility that needs this discharge allowance from a technical operations standpoint. Duke Energy installed a remote mechanical drag system (RMDS) in February 2018 with the intent to operate the system without discharging BATW. Shortly after start-up, however, recirculating water needed to be discharged due to extremely low pH (i.e., less than 3.0). As EPA notes in the proposal, steps can be taken to address pH, but at this facility these steps led to increased accumulation of Total Dissolved Solids (TDS) and—without a blowdown—would have resulted in increased scaling. The scaling in turn would lead to plugging of small diameter piping, thereby impacting the operation of the pumps. Additionally, that system as well as RMDS Duke Energy has installed at other units have experienced premature failures of pump seals, valves, and piping elbows due to erosion from fine particles contained in the BATW. While Duke Energy is exploring ways to address fine particles—like pH neutralization—these steps can often lead to additional issues unless a blowdown is allowed. As a result, utilizing limited blowdown can lead to both improved operations, reduced costs for customers by reducing equipment failures, as well as improved environmental outcomes by avoiding premature equipment failures and any unintended discharges that could result.

[11] While closed-loop systems may utilize a series of basins and ponds to treat bottom ash transport water prior to its reuse in the system or discharge, the bottom ash is separated from the water via a mechanical dewatering system prior to the water being circulated through such features and then recirculated back into the system or ultimately discharged. Crucially, this differs from the surface impoundments previously set as the Best Performing Technology (BPT), since those impoundments were ponds in which both bottom ash *and* BATW were stored, and that were

subject to the litigation in SWEPCO, discussed infra, since they do not contain any Coal Combustion Residuals (CCRs) and are instead used to dewater the CCR. EPA should clarify this point and include specific language in the final rule that surface impoundments that do not meet the definition of "CCR surface impoundments" in 40 C.F.R. 257.2 are considered primary active wetted bottom ash systems.

[12] "Since the 2015 rule, the EPA's understanding of …the ability of wet systems to achieve complete recycle has changed."

[13] BCCA Appeal Grp. v. EPA, 355 F.3d 817, 824 (5th Cir. 2003) (EPA is entitled to special deference where its decision turns on "its evaluation of complex scientific data within its technical expertise.").

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 13

Comment Excerpt:

EPA also should include in its final rule an allowance for additional discharges beyond the 10 percent 30-day rolling average where necessary to account for large-scale natural disasters, such as hurricanes, floods, and other events that can overwhelm current BATW engineering systems due to heavy and prolonged precipitation. These storm events can be more frequent than EPA's cited 25-year event time horizon. Id. at 64,636.[14] For example, TVA calculated the direct precipitation on its existing bottom ash dewatering and recirculation footprint at Bull Run that resulted from a 10-year, 24-hour event. Direct precipitation was calculated to be approximately 230,000 gallons. A 100-year, 24-hour event resulted in approximately 353,000 gallons or a 123,000 gallon increase—substantially more than a 10 percent increase. Extreme or successive storm events could produce a volume greater than the total 10 percent allowable purge volume of approximately 42,000 gallons at Bull Run. As direct precipitation can only become BATW when it mixes with existing BATW, precipitation events in excess of the specified design rainfall event should be given a separate blowdown allowance subject to total suspended solids (TSS) limitations. The Agency should consider clarifying and treating both categories consistently.

[14] For example, the relative frequency of once-in-five-year precipitation events falling over a two-day period has been 40 percent higher in the last two decades than in the 1950s. See Center for Climate and Energy Solutions, Extreme Precipitation and Climate Change, Observed U.S. Trend in Heavy Precipitation, http://www.c2es.org/content/extreme-precipitation-and-climatechange/.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 14

Comment Excerpt:

EPA likewise should likewise provide additional clarity in the final rule with respect to how permit writers should calculate the 10 percent 30-day rolling average. [15] Specifically, EPA should define the calculation in a manner consistent with accounting for operational variability that permit writers might need to consider based on unit characteristics, operational limitations, and other source-specific factors. EPA also should provide guidance on remote mechanical drag systems and dewatering bins.

[15] EPA should aim to provide broad guidance to help permit writers move forward, but not be so restrictive as to limit potentially addressing essential site-specific flexibilities in setting both the volume and the BAT basis for treatment of the blowdown.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 4

Comment Excerpt:

APPA supports allowing a limit purge from high recycle rate BA transport water systems. We recommend EPA modified the purge conditions as discussed in these comments.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 14

Comment Excerpt:

VII. APPA SUPPORTS THE 10 PERCENT BY VOLUME PURGE OF BA TRANSPORT WATER SYSTEMS

EPA is proposing to control pollutants from BA transport water by establishing BAT limits and PSES on the volume of BA transport water that can be discharged based on high recycle rate system. EPA proposes some relief by way of allowing limited discharges compared to the nearly zero discharge limit it applied in the 2015 Rule. The proposal would allow discharge of a "30-day rolling average of ten percent of the primary active wetted bottom ash system volume."[24] However, there are some strict provisions regarding the conditions under which this 10 percent by volume discharge would be allowed. The Association would recommend some adjustments to clarify the Proposal Rule. The ability to blowdown a small side stream from BA transport water recirculating systems under certain limited conditions will enable facilities to operate their BA transport water systems in ways that avoid excessive corrosion, scaling, and premature failure of equipment and increase system reliability, including the energy efficiency of the whole unit. This proposal would improve the longevity of recirculating systems (and thus their overall feasibility), while greatly reducing pollutant loadings.

A. The BA Transport Water Purge Conditions Should be Modified

The Proposed Rule outlines four conditions by which the 10 percent volumetric discharge would be allowed. Those conditions are as follows:

- maintenance of system water balance due to certain precipitation-related inflows;
- maintenance of water balance when regular inflows from wastestreams other than BA transport water exceed the ability of the system to accept recycled water;
- performance of certain maintenance activities; and
- maintenance of system water chemistry when the facility is unable to manage pH, corrosive compounds, and fine particulates.[25]

All of these conditions are reason enough to allow the BA transport water system purge.

24 Proposed Rule § 423.13(k)(2)(i)(B).
25 Proposed Rule § 423.13(k)(2)(i)(A)(1-4).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 29

Comment Excerpt:

1. Precipitation Related Inflows Should Not Count Against Purge Volume

As proposed, the 10 percent by volume rolling 30-day average purge allowance must account for all the BA transport water purge conditions. For example, if a facility experienced a major maintenance event and had to drain the system and then had water chemistry imbalances and a couple of major precipitation events, only that part of the combined discharges up to the 10 percent by volume threshold would be allowed to be discharged. Including precipitation events in this condition is problematic as it is challenging for an operator to estimate 30-day rain fall. More often, forecasts are inaccurate and make it difficult to judge the intensity and location of the storm event. Also, the variability of storm events across the country means that the utility of the 10 percent by volume purge will be reduced in areas subject to very large storm events. Plants in heavy rainfall areas will be penalized, as they will have to reduce their purges to account for greater amounts of precipitation inflows.

The benefit of a discharge allowance is in the certainty of being able to discharge a set amount in most, if not all, conditions. This certainty allows engineers to design a system that accounts for the discharge allowance. If the facility must account for the possibility of reaching the discharge limit due to unpredictable precipitation inflows, then the design engineer will need to increase the capacity of the system to ensure against "worst case" situations.

The Proposed Rule calls for maintaining the system water balance when precipitation related inflows within any 24-hours period resulting from a 25 year, or multiple consecutive events cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment."[26] APPA recommends amending this provision to require a 10-

year, 24-hour or greater storm event, or an extended rainfall event or events within a rolling 7-day period, which cumulatively are equivalent to, or greater than, the 10-year, 24-hour storm event. The 10-year, 24-hour storm event is a defined metric used, under the steam electric effluent guidelines, any untreated overflow of coal pile runoff from a system designed, constructed, and operated to treat the volume of coal pile runoff associated with a 10-year, 24-hour storm event is not subject to the coal pile runoff limits. [27] Finally, the first condition also references "installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment." EPA did not include spare, redundancies, maintenance tanks, and other secondary bottom ash system equipment in the BA transport water modeled technology. Thus, the reference to additional equipment should be removed. The rule should be clear that purchase and installation of additional components is not mandated or recommended.

If the final rule includes a volumetric purge of 10 percent by volume, EPA need not be concerned that utilities will elect not to use installed spares or redundancies as the NPDES provisions include an anti-bypass provision. Bypasses are expressly prohibited except in very limited circumstances, and the rule requires use of "auxiliary treatment facilities."[28]

26 Proposed Rule § 423.13(k)(2)(i)(A)(1).
27 40 C.F.R. § 423.12(b)(10).
28 40 C.F.R. § 122.41(m)(4)(B).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 30

Comment Excerpt:

2. The Second Water Balance Condition Should be Clarified

The second water balance condition as proposed deals with water imbalances caused by regular inflows. The provision reads as follows:

The discharge of pollutants in bottom ash transport water from a properly installed, operated, and maintained bottom ash system is authorized under the following conditions:

(2) to maintain system water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is [sic] feasible.[29]

This provision would require the permit writer to determine when it is "not feasible" to segregate certain wastestreams from BA transport water and therefore when water balances may be exceeded based on regular inflows. As written, this provision leaves permit writers without any guidelines for what wastestreams are or are not feasible to segregate. APPA recommends replacing this provision with the following: "(2) to maintain water balance consistent with system design."

29 Proposed Rule § 423.13(k)(2)(i)(A)(2).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 31

Comment Excerpt:

3. Modify the Third Condition on Maintenance to Remove References to Additional Equipment

As proposed, the third condition on maintenance reads as follows:

(3) to conduct maintenance not otherwise exempted from the definition of transport water in 423.11(p) when water volumes cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment.[30]

This condition mentions additional equipment beyond what EPA has included in the model BA transport water technology, potentially creating confusion about what types of equipment constitute the model technology and how a permit writer should interpret the condition. APPA recommends that the condition be simplified to read: "(3) to conduct maintenance not otherwise exempted from the definition of transport water in 423.11(p)." This is a straightforward provision only exempting maintenance-related purges.

30 Proposed Rule § 423.13(k)(2)(i)(A)(3).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 32

Comment Excerpt:

4. Modify the Fourth Condition on Water Chemistry

As proposed, the fourth BA transport water purge condition reads:

(4) to maintain system water chemistry where installed equipment is unable to manage pH, corrosive compounds, and fine particulates to below levels which impact system operations.[31]

APPA recommends two clarifications for this provision. First, the term "corrosive substances" would be better than "corrosive compounds" to avoid confusion over whether corrosives that are not compounds are covered under the provision. The intent appears to be to cover all types of corrosives, whether they are compounds or not. Therefore, "corrosive substances" is a better catch-all term.

Second, this provision mentions "installed equipment" just as two of the other conditions refer to "installed spares" and "redundancies." As with the other conditions, including the wording "installed equipment" in this condition creates confusion as to whether additional equipment beyond the model technology is required. It is also unwarranted because, as previously discussed, the NPDES bypass rules ensure appropriate use of all installed equipment.

31 Proposed Rule § 423.13(k)(2)(i)(A)(4).

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 4

Comment Excerpt:

C. CCIG Strongly Supports Proposed Numeric Effluent Limitations for Bottom Ash Transport Water

1. EPA's Proposed Revisions to the BATW Limits Are Necessary and Appropriate

CCIG strongly supports EPA's proposed revisions to the numeric effluent limitations for BATW. EPA's proposed revisions – the 10% discharge allowance included in the Proposed Rule, the model technology, inclusion of quench water in the definition of dry bottom ash system, and the exclusion of discharges associated with plant retirement or decommissioning from the definition of bottom ash transport water – are both necessary and appropriate. Because of its zero discharge provision for closed-loop systems, the 2015 ELG Rule would have resulted in significant and unecessary compliance costs: most notably, companies that already utilize high recycle rate systems would have needed to expend significant sums exceeding the scope of reasonableness to close a small gap and make those systems completely zero discharge, with little or no environmental benefit.[9] Additionally, compliance with the 2015 ELG Rule's zero discharge provision in combination with the short compliance timeframes under the Coal Combustion Residuals (CCR) rule would have caused process and engineering challenges and limited facilities' compliance options.[10] As proposed, the revisions to the 2015 ELG Rule provide companies the flexibility to deal with precipitation or maintenance events and maintain adequate water quality without imposing excessive process or financial burdens on regulated entities. CCIG therefore encourages EPA to finalize the proposed 10% discharge allowance. As an example showing the need for the 10% BATW purge allowance – and the fact that it can be managed in an environmentally responsible fashion that protects water quality – Duke Energy installed a remote mechanical drag chain system (RMDS) at the Cayuga Generating Station in

February 2018 and has attempted to operate the system without discharging BATW. Shortly after start-up, however, recirculating water needed to be discharged due to extremely low pH (i.e., less than 3.0). As EPA notes in the Proposed Rule, steps can be taken to address pH,[11] but these steps often lead to additional issues. For Cayuga, steps taken led to increased accumulation of total dissolved solids (TDS) and without a blowdown would have resulted in increased scaling, leading to plugging of small diameter piping and affecting the operation of the pumps. Additionally, RMDS have experienced premature failures of pump seals, valves, and piping elbows due to erosion from fine particles. Industry is exploring steps to address fine particles, but like pH neutralization, these steps can often lead to additional issues unless a blowdown is allowed. Stations such as the Cayuga generating station can send BATW to the FGD scrubber, but operational concerns and low capacity factors affect how much, if any, BATW can be sent to the FGD scrubber. Stations will still take measures to ensure the 10% purge allowance will not adversely impact water quality. At Duke Energy, for example,, concrete lined retention basins to treat and manage miscellaneous waste streams such as coal-pile runoff, contact stormwater, and floor drain wastewater were constructed. These systems consist of two treatment basins with pH adjustment, polymer addition, and retention time to promote solids settling and treatment, which are suitable measures for managing the discharge from BATW systems. The majority of metals typically detected in BATW are in the particulate form, which can be effectively controlled by managing total suspended solid (TSS).

[9] Proposed Rule, 84 Fed. Reg. at 64,635.
[10] Id.
[11] See, e.g., id. at 64,636 (listing acid or caustic addition as pH control measures).

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 5

Comment Excerpt:

2. Limited Requests for Clarification or Revision

While the Group strongly supports EPA's proposed numeric effluent limitations on BAT for BATW, there are several proposed revisions that should be revised to ensure consistency with other regulations as well as clear compliance obligations for the regulated community:

- 25-year 24-hour storm event. EPA proposes to use the 25-year 24-hour storm event as one of the situations during which the discharge of BATW is authorized.[12] This is inconsistent with the regulations that exempt from BATW treatment requirements the untreated overflow from facilities designed, constructed, and operated to treat coal pile runoff resulting from a 10-year, 24-hour storm event.[13] CCIG respectfully requests that EPA revise this provision to be consistent with other regulations and use the 10-year, 24-hour storm event as the basis for this exemption.
- Volumes included in the bottom ash wetted volume calculation. One of the reporting and recordkeeping standards included in the Proposed Rule is a proposed requirement for

facilities operating high recycle rate bottom ash systems to submit the calculation of the primary active wetted bottom ash system volume, i.e., the maximum volumetric capacity of BATW in all piping (including recirculation piping) and primary tanks of a wet bottom ash system.[14] EPA's current proposal excludes the volumes of installed spares, redundancies, maintenance tanks, other secondary bottom ash system equipment, and non-bottom ash transport systems that may direct process water to the bottom ash system.[15] However, in order to ensure the accuracy and consistency of data across the subcategory, EPA should include the volumes of installed spares, redundancies, maintenance tanks, other secondary bottom ash system equipment, and non-bottom ash transport systems in the bottom ash wetted volume calculation. These components are integral parts of the wastewater treatment system and should not be excluded from the wetted bottom ash system volume calculation. Further, EPA should clarify in the final rule or associated preamble that companies in coordination with the permitting authority can describe and define in their permit the particular components of their specific "primary active wetted bottom ash system" that serve as the basis for the ultimate volume calculation. This clarification will ensure that the definition can adapt to a variety of different BATW high recycle rate systems, while providing for appropriate oversight by the regulator and the community through the permit issuance process.

[12] Id. at 64,636 fn. 45.
[13] 40 C.F.R. § 423.15(a)(11)-(12).
[14] Id. at 64,666.
[15] Id.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 11

Comment Excerpt:

TVA agrees with EPA's assessment based on industry input that bottom ash transport water (BATW) systems have only been "partially closed" (Page 64634) and that high recycle systems are preferred as BAT instead of the previous 2015 ELG no discharge of BATW requirement. The ability to discharge is necessary to maintain BATW system volumes and chemistry due to storm events, corrosion, scaling, fines buildup, etc. Allowing a purge stream is reasonable, and is consistent with allowing purge discharges from cooling towers that are also high recycle systems.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 12

Comment Excerpt:

In response to EPA's request for comments on an alternate approach to BATW system discharges to allow a purge discharge rate higher than 10% adjusted upwards based on site-specific operating data (Page 64636), TVA believes that EPA should adopt a more flexible approach for minimizing the volume of BATW system discharges. One approach would be to set a tiered allowable purge volume: If a site were able to comply with a 10% maximum purge of system volume, then that should be the limit for the site. If, however, a well-operated system needed additional blowdown quantities due to unique factors related to the system and site, then development of a site-specific discharge minimization plan with a higher than 10% blowdown upper limit should be allowed for in the ELGs. TVA's concern is that there are too many variables that affect maintaining water balances due to site-defined inflows, intake water quality, storm events, type of coal burned, inclusion of economizer ash, ability to use blowdown in FGD absorbers, etc., to establish a prescriptive national maximum 10% standard for blowdown quantity. Since achieving the 10% blowdown standard would be less onerous than establishing a site-specific standard, sites would have an incentive to adopt the 10% standard if it were feasible. However, for sites where achieving the 10% blowdown limit is not feasible, a site-specific limit that may be somewhat higher than 10% is appropriate.

Another approach would be to exclude storm events above a given storm event design standard from the calculation of the 10% BATW purge maximum. Depending upon the storm event or series of storm events, additional volumes needing to be managed due to direct precipitation on the BATW dewatering/recirculating site could be significant. TVA calculated the direct precipitation on its existing bottom ash dewatering and recirculation footprint at Bull Run from a 10-year, 24-hour event. Direct precipitation was calculated to be approximately 230,000 gallons. A 100-year, 24-hour event resulted in approximately 353,000 gallons or a 123,000 gallon increase. Extreme or successive storm events could produce a volume greater than the total 10% allowable purge volume of approximately 42,000 gallons at Bull Run. As direct precipitation only becomes BA TW due to its mixing with BA TW, precipitation events in excess of the specified design rainfall event could be given a separate blowdown allowance subject to total suspended solids (TSS) limitations. As direct precipitation does not contribute pollutant mass loadings, an additional purge volume could be allowed without significantly changing the pollutant mass loading to the receiving stream even after mixing with the other BATW flows in the remote mechanical drag island.

Either approach or a combination of approaches outlined above appropriately recognizes the variety of unique site-specific factors that affect blowdown volume. Because of these site-specific factors, TVA does not agree that these discharges should be capped at a specific flow in response to EPA's solicitation of comment about that approach (Page 64636), nor does TVA support a national standard of less than 10% of the wetted volume.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 4

Comment Excerpt:

<u>Duke Energy Supports EPA's Model BAT Technology for Bottom Ash Transport Water</u>

Duke Energy supports EPA's proposal identifying high recycle rate systems as the BAT technology basis for control of pollutants discharged in BA transport water. Duke Energy has installed remote mechanical drag systems (RMDS) at six stations with the goal to operate these systems as no discharge of BA transport water to meet the 2015 ELG Rule. Based on our recent experience, it is extremely difficult to operate a RMDS in a 100% closed-loop manner. As EPA identifies in the proposal, water imbalances within the system, such as those associated with stormwater, and water chemistry, including acidity and corrosiveness, scaling, and fines buildup, create challenges to operating these systems to eliminate the discharge of BA transport water. As an example, Duke Energy installed a RMDS at the Cayuga Generating Station in February 2018 with the intent to operate the system without discharging BA transport water. Shortly after startup, however, recirculating water needed to be discharged due to extremely low pH (i.e. less than 3.0), (refer to Attachment A).[8] As EPA notes in the proposal, steps can be taken to address pH, but these steps can lead to unintended consequences. At Cayuga, a soda ash system to neutralize the pH was installed. This, however, led to increased accumulation of total dissolved solids (TDS) and without a blowdown would result in increased scaling leading to plugging of small diameter piping and affecting pump operations. Additionally, the system at Cayuga as well as RMDS at other stations have experienced premature failures of pump seals, valves, and piping elbows due to erosion from fine particles. Duke Energy is exploring steps to address fine particles, such as the addition of flocculate to promote settling, but like pH neutralization, these steps can often lead to additional issues unless a blowdown is allowed. The allowance to send BA transport water to the FGD can help alleviate some of these issues, but operational concerns and low capacity factors can affect how much, if any, BA transport water can be sent to the scrubber.

8 If allowed to be discharged, any low pH water would be neutralized in the low volume retention treatment basins prior to discharge to surface waters to comply with water quality standards and the best practicable control technology (BPT) limits for pH (see 40 CFR 423.12(b)(1)).

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 6

Comment Excerpt:

<u>EPA Should Consider Allowing Discharges Associated with Storm Events Outside of the 10% Discharge</u>

EPA proposes to allow a discharge from the BA transport water associated with precipitation-related inflows within any 24-hour period resulting from a 25-year, 24-hour storm event.[9] However, the volume of this discharge would have to be counted against the 30-day rolling average of the 10% allowable discharge. Under the proposed revisions, it is assumed that facilities can manage inputs from storm events along with water chemistry and other causes of water imbalances within the system; however, this may not always be the case. Duke Energy requests that EPA consider allowing storm event related discharges without subjecting these discharges to the 10% discharge allowance. Rainfall frequencies and amounts, though forecasted, can be unpredictable and uncontrollable and at times exceed expected volumes. Under these circumstances, non-compliance with the 10% discharge allowance could occur as facilities effectively manage the water chemistry of the system, the non-BA transport water inputs and maintenance only to have an unpredictable and uncontrollable storm event result in an exceedance of the limit. Additionally, stations within hurricane prone areas, such as Florida and the Carolinas, would be disproportionately affected by including discharges associated with storm events in the 10% allowance. BA transport water systems within these areas would have to be built with additional storage capacity to account for the volume of these large storm events.

It is also important to note that wet BA transport systems have minimal means to remove water from the closed loop process. Several of those means such as purging to the FGD scrubber, moisture content in bottom ash, and evaporation require the facility to be operating. Given that many Duke Energy coal-fired stations operate infrequently, issues arising from unpredictable and uncontrollable storm events will further be exacerbated. Duke Energy requests that storm events are allowed but excluded from the 10% discharge allowance to allow facilities flexibility in managing their wet bottom ash transport systems water balances. Additionally, EPA should consider revising the allowable storm event to the 10-year, 24-hour storm event to be consistent with the limitations for coal pile runoff.[10]

9 84 Fed. Reg. 64,622 (Nov. 22, 2019).
10 40 C.F.R. § 423.15(a)(11)-(12).

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 5

Comment Excerpt:

Bottom ash transport water

- We support EPA's proposed allowance to discharge up to 10% by volume per day, based on a 30-day rolling average, and recommend certain modifications to the qualifications associated with the ability to purge.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 32

Comment Excerpt:

V. SOUTHERN COMPANY SUPPORTS A 10% VOLUMETRIC PURGE FOR BATW AND RECOMMENDS CERTAIN MODIFICATIONS

A. EPA's Proposed 10% by Volume Discharge Allowance for High-Recycle-Rate Systems is an Appropriate Adjustment to the Rule.

Southern Company supports EPA's proposal to allow a 10% by volume per day discharge based on a 30-day rolling average from high-recycle-rate BATW systems, while recommending some amendments to clarify the proposal. The ability to purge a small amount from the recirculating system under certain limited conditions will enable facilities to operate their BATW systems to avoid scaling, corrosion, and buildup of fines while also increasing system reliability. It will also provide flexibility to perform routine inspections and maintenance as well as maintenance on the systems due to unexpected equipment failures. This allowance would improve the longevity of high-recycle-rate systems while greatly reducing pollutant loadings.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 33

Comment Excerpt:

1. The Southern Company system's experience.

The Southern Company system installed Remote Mechanical Drag-Chain Systems ("RMDS") at four facilities between 2015-2019. The components of these high-recycle-rate systems include drag chain conveyors, caustic feed skids, overflow and surge tanks, concrete storage bunkers, sumps, high-pressure recirculation pumps, and balance-of-plant scope including piping, electric and utility services. However, the redundancies and sizes of these systems are all site-specific. The systems operate at a high recycle rate, but under certain situations it has become necessary to purge the systems, even though they have only been in service for approximately a year and have yet to be stressed under all operational ranges. The following are actual examples of major maintenance activities requiring purges that have occurred since these systems have become operational:

1. Conveyor ash overloading conditions required RMDS draining and subsequent evacuation of the RMDS by a vacuum truck. Draining the RMDS was the only plausible option to remove ash from the system once the RMDS shut down.
2. An operational issue known as bottom ash hopper “bridging” occurred. This condition is where the bottom ash accumulates over the opening to the clinker grinder housing due to a large clinker from the boiler not fitting through the clinker grinder housing opening. This is often the result of changes to coal quality or excessive slag build-up in the boiler. When this occurs, the clinker grinder housing must be opened to break up the bridged material. This typically entails draining the bottom ash hopper to a sump which routes the BATW to the low-volume waste treatment system.
3. At several facilities, unexpected debris has carried over from the boiler or hopper area and entered bottom ash hoppers, grinders, storage tanks, pump suctions, and various piping components. This leads to plugging of the tanks, piping and pumps. Some of these components required complete draining to correct the issue.
4. Routine tank inspections require complete drainage of the tank for both practical and safety considerations prior to tank entry. It is not feasible to maintain a closed-loop water balance and conduct these inspections.

In addition to major maintenance events that have occurred since the systems have become operational, there have been challenging water chemistry issues and an accumulation of fines that necessitated purges. Economizer and selective catalytic reduction system (“SCR”) ash have always been co-managed with the bottom ash. The inclusion of this ash into the RMDS introduces fine material that is harder to effectively convey than typical bottom ash material. Accumulations of these fine materials have proven to be problematic and have resulted in draining of tanks and pump suction piping. Retrofits required to route economizer and SCR ash to the dry fly ash system would be extensive and costly.

Based on the Southern Company system’s operational experience with RMDS, our engineers believe a 10%-by-volume per-day discharge is needed for high-recycle-rate BATW systems. Since the Southern Company system began operating its RMDS, there have been several circumstances necessitating discharge. Attempting to meet a zero-discharge limit severely restricts operational flexibility and would result in instances of unavoidable NPDES permit noncompliance, as well as additional costs. Therefore, it is both appropriate and necessary for EPA to set a 10% by volume per day discharge based on a 30-day rolling average from high-recycle-rate BATW systems, such as an RMDS.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 34

Comment Excerpt:

B. The Conditions for BATW Purging Should be Amended.

In addition to a not-to-exceed cap of 10% of the primary active wetted bottom ash system volume, facilities will only be allowed to purge if one of the following four conditions has been met:

1. To maintain system water balance when precipitation-related inflows within any 24- hour period resulting from a 25-year, 24-hour storm event, or multiple consecutive events cannot be managed by *installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment*; or
2. To maintain water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is not feasible; or
3. To conduct maintenance not otherwise exempted from the definition of transport water in § 423.11(p) when water volumes cannot be managed by *installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment*; or
4. To maintain system water chemistry where *installed equipment* at the facility is unable to manage pH, corrosive compounds, and fine particulates to below levels which impact system operations.[70]

References to "installed spares, redundancies, maintenance tanks and other secondary bottom ash system equipment" and "installed equipment" create confusion about what constitutes the model technology and how a permit writer should interpret the conditions. EPA does not include installed spares, redundancies, maintenance tanks, or other secondary equipment in its RMDS model BATW recirculation technology. Therefore, Southern Company recommends that these references to additional components be deleted. The rule should be clear that purchase and installation of additional components is not mandated to satisfy the BAT standard, including the ability to periodically purge, and are not considered a component of the model BAT.

EPA may be concerned that facilities that have installed spares or redundancies would choose not to use these portions of their systems once the proposed rule allows a 10% by volume purge. However, the anti-bypass provisions of the NPDES regulations already prohibit any bypassing of existing equipment. Bypasses are expressly prohibited except in very limited circumstances, and the rule requires use of "auxiliary treatment facilities."[71]

Furthermore, any concern that facilities would not efficiently operate the BATW systems does not account for the realities of power plant ash management. The proper operation and maintenance of the RMDS is incentivized by the fact that BATW purges to the low volume waste system are required to meet TSS limitations, which would necessitate larger and more robust systems if purging the bottom system was to occur on a frequent basis.

If EPA elects to leave this problematic language in the final rule, it must clarify its purpose and how it is to be interpreted to avoid inconsistent or mistaken application by permit writers.

70 Proposed Rule, 84 Fed. Reg. at 64,674 (to be codified at 40 C.F.R. § 423.13(k)(2)(i)(A)) (emphasis added).
71 40 C.F.R. § 122.41(m)(4)(i)(B).

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 35

Comment Excerpt:

C. The Additional Control Measures Provision Should be Clarified.

In addition to the four purge conditions described above, EPA proposes additional control measures, including best management practices ("BMPs"):

The total volume necessary to be discharged for the above activities shall be reduced or eliminated to the extent achievable using control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice, and in no instance shall it exceed a 30-day rolling average of 10% of the primary active wetted bottom ash system volume.[72]

This provision is very vague. It is not clear what is meant by "reduced or eliminated to the extent achievable" or "control measures (including best management practices)." Clarity is needed if this language remains in the final rule. As written, this regulatory provision could cause permit writers to effectively conduct another ELG rulemaking prior to setting the actual technology-based effluent limitations in permits issued to the industry. For instance, an extensive analysis would be required to determine if the permittee could reduce the 10% by volume discharge by adding on additional technologies beyond EPA's model technology, performing best management practices, or applying other control measures. Perhaps worse, a permit writer could forego the aforementioned analysis and simply incorporate this proposed regulatory language in permits. This would invite second-guessing of every purge event and present an open-ended enforcement or litigation risk for the facility. That would be unworkable. In short, EPA's proposal essentially grants an owner the ability to perform critical tasks for system operation by periodically purging a small volume of water from a high-recycle-rate system, but at the same time seemingly limits this capability by imposing additional, subjective restrictions and requirements that invite post hoc second-guessing of any purge that occurs.

Southern Company recommends revising proposed 40 C.F.R. § 423.13(k)(2)(i)(B) so that it (1) sets a not-to-exceed cap on BATW purges of 10% of the primary active wetted bottom ash system volume for all discharges related to major maintenance events,[73] water imbalances (excess water), or chemistry imbalances (e.g., corrosive issues); (2) requires documentation of a daily log of all BATW purges, including a description of the basis for the purge; and (3) requires the permittee to conduct a BMP study to evaluate whether the system is maximizing recycling with the high-recycle-rate system.[74] Such a study would facilitate the development of a site-specific BMP plan for governing effective operations.

Southern Company recommends that the BMP plan be submitted to the permitting authority within one year after the later of (1) commissioning a high-recycle-rate BATW system or (2) the effective date of the permit. The permit would require the permittee to implement any feasible

BMPs identified in the plan to maximize recycling of the system, following approval by the permitting authority.

72 Proposed Rule, 84 Fed. Reg. at 64,674 (to be codified at 40 C.F.R. § 423.13(k)(2)(i)(B)).
73 Minor maintenance events are excluded from the definition of "transport water." 40 C.F.R. § 423.11(p).
74 For an RMDS, these components, as described by EPA, are: an RMDS, a sump, recycle pumps, a chemical feed system, and a semi-dry silo. EPA, SUPPLEMENTAL TECHNICAL DEVELOPMENT DOCUMENT, supra note 20, at 5-33. For a dewatering bin system, as EPA described in the 2015 rule, the model technology would be two dewatering bins with two settling tanks and any associated sumps, piping and pumps. See EPA, TECHNICAL DEVELOPMENT DOCUMENT FOR THE EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR THE STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY 7-40 (2015) (Docket ID No. EPA-HQOW-2009-6432).

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 1

Comment Excerpt:

Bottom Ash Transport Water
FirstEnergy appreciates EPA's review and update of the Bottom Ash Transport Water ("BATW") sections by updating cost information for 'closing the loop' and proposing that high recycle rate systems represent Best Available Technology ("BAT"); however, FirstEnergy has certain concerns with the BATW sections of the ELG Rule as they are currently proposed.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 7

Comment Excerpt:

BATW Purge Conditions
While FirstEnergy supports the need for a purge from BATW systems, the Proposed ELG Rule has created cumbersome requirements that are quite prescriptive and do not necessarily make sense in practice. Specifically, proposed conditions 40 CFR 423.13(k)(2)(i)(A) and (B) create requirements that the permittee could not prove until the facility is operational; however, the permit writer would need to know the information in order to grant a construction permit and permit modification. For instance, the Proposed ELG Rule states in 40 CFR 423.13(k)(2)(i)(A)(2), "To maintain water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is not feasible." See 84 Fed. Reg. at 64,674. However, the permittee and permit writer would not know under all operational conditions when the non-BATW exceeds the ability of the bottom ash system to accept the water. FirstEnergy

proposes that EPA instead focus on a best management plan ("BMP") for controlling and minimizing the purge to the extent practicable while not exceeding 10 percent, by volume, over a 30-day average. The BMP plan condition, as detailed in UWAG's comments, would perform a study looking at various aspects of the BATW systems over the first permit term of the high recycle rate system and identify any additional opportunity to maximize the recycle rate.

Within 40 CFR 423.13(k)(2)(i)(A)(1), the Proposed ELG Rule states, "To maintain system water balance when precipitation-related inflows within any 24-hour period resulting from a 25-year, 24-hour storm event, or multiple consecutive events…" See 84 Fed. Reg. at 64,674. The Proposed condition is inconsistent within the existing ELG Rule for coal pile runoff. The coal pile runoff stormwater condition is for a 10-year, 24-hour storm, and is not included as part of an overall limit. By definition, a10-year, 24-hour storm has only a 10 percent chance of occurrence in a given year and is likely to occur only once every 10 years. A 10-year storm event would statistically only occur for only two days over the life of the equipment (20 years), while a 25-year storm would have a negligible additional benefit at 0.8 days over the life of the equipment. FirstEnergy proposes that EPA change the Proposed ELG Rule to be consistent with the coal pile runoff and to be exempt from the 10 percent purge limit once the storm event threshold is met.

A compounding factor with proposed condition 40 CFR 423.13(k)(2)(i)(A)(1) is that it is inclusive of the 10 percent purge threshold. As EPA has created the proposed condition, a permittee may be able discharge within the 10 percent purge for a given storm event, however it is unknown to what maximum storm event does the facility design to. For instance, if a facility has a maintenance outage on the system and must discharge close to the 10 percent threshold over the first 25 days of the 30 day period for the maintenance to occur, and a major storm event occurs, how does the permittee prevent a discharge for the storm event? The permittee could not have reasonably planned for the storm event 25 days prior, nor could it have prevented the Act of God from occurring. It was through no fault of the permittee that the discharge threshold of 10 percent was exceeded. The proposed condition is arbitrary and capricious and creates an overly burdensome design requirement for these exceptional events. As stated above, FirstEnergy proposes that the condition be consistent with the coal pile runoff and to be exempt from the 10 percent purge limit once the storm event threshold is met.

Further, EPA assumes that permittees will be able to send BATW to the FGD system. While FirstEnergy supports the condition, due to water balance, temperature, and chemistry concerns, FirstEnergy does not believe this is a panacea or option for all permittees. Fort Martin Power Station ("Fort Martin") has design flue gas temperature issues affecting the FGD water balance that will inhibit the use of BATW. EPRI studies have also found that changes in scrubber chemistry can promote mercury reemission issues that affect compliance with the Mercury and Air Toxics Standards ("MATS") mercury limits.[1] At Harrison, the FGD system receives leachate wastewater, so it would struggle to accommodate additional water. FirstEnergy has contracted with third party engineering firms that support this information.

FirstEnergy's Fort Martin Power Station and Harrison Power Station both have unique bottom ash systems that make meeting a 10 percent, by volume, 30-day average purge impossible when retrofitting the bottom ash system. Fort Martin and Harrison both make use of cooling tower blowdown water as their bottom ash influent water. As such, cooling tower chemistry is maintained through the bottom ash system water balance. In essence, for Fort Martin and Harrison to comply with Proposed ELG Rule BATW conditions, a new water supply system would be needed for the bottom ash process and a new water discharge system for the cooling tower process. These additional systems are required for each unit and will significantly drive up the cost to comply with the Proposed Rule. Also, segregation of the Fort Martin and Harrison systems would lead to additional surface water withdrawals to provide source water to each system (versus just the cooling tower system). In particular, Harrison is on a small water body, the West Fork River, which makes additional water withdrawals even more environmentally unfavorable. FirstEnergy recommends that EPA consider these co-mingled, large volume waters and supports the development of a Best Management Plan as the Proposed ELG Rule has created for low utilization boilers.

1 Mercury and Air Toxics Control Update. EPRI, Palo Alto, CA: 2014. 3002003403.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 4

Comment Excerpt:

B. The allowance for a minimal discharge from a wet BATW system is necessary.

The allowance in the proposal to permit facilities with a wet transport system to discharge up to 10% of the system volume on 30-day rolling average is necessary when operating a high recycle rate system. An allowance for discharge when necessary will enable operators to address a variety of challenges, such as operational and maintenance issues like scaling and corrosion or water quality issues such as pH.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. (“Vistra”)
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 2

Comment Excerpt:

Vistra generally supports EPA’s Proposed Rule, particularly EPA’s proposal to develop subcategories for boilers retiring by 2028 and low utilization boilers and EPA’s proposal to add a 10 percent volumetric purge allowance for recirculating bottom ash transport water systems;

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 5

Comment Excerpt:

Further, Vistra supports the addition of a 10 percent volumetric purge allowance, which will help to avoid unnecessary detrimental impacts to recirculating bottom ash transport water systems.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 12

Comment Excerpt:

In the Proposed Rule, EPA correctly recognizes that recirculating bottom ash transport water systems face certain, unique challenges that tend to be compounded when considered in conjunction with the CCR rule. In particular, "facilities often send various CCR and non-CCR wastestreams, such as coal mill rejects, economizer ash, etc., with [bottom ash] transport water into their surface impoundments."[24] This "can lead to or exacerbate problems with scaling, corrosion, or plugging of equipment."[25] However, purging the system on occasion can help to address these issues. Therefore, EPA proposes to allow facilities with a recirculating bottom ash transport water system, "on an 'as needed' basis, to discharge up to 10 percent of the system volume per day on a 30-day rolling average to account for" these challenges.[26] Vistra supports this proposal and agrees that operators of recirculating bottom ash transport water systems need to purge their systems from time-to-time for a variety of reasons, including to avoid detrimental impacts to their systems from issues like scaling and corrosion. Accordingly, EPA should finalize its proposal to adopt a 10 percent volumetric purge allowance for these systems.

[24] 84 Fed. Reg. at 64,635.
[25] Id.
[26] Id.

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 12

Comment Excerpt:

2. Facility-Specific Alternatives to the 10% Daily Purge Limit

The preamble to the proposed rule solicits "comment on a facility-specific recycle rate alternative to the 10 percent 30-day rolling average option" for maintenance purge water discharges.[61] The preamble explains that such an alternative might be available "when reasonable active measures are insufficient to maintain system water chemistry or water balance within acceptable limitations, or to facilitate maintenance and repairs of the BA[TW] system[.]"[62] The allowed discharge "would be determined based on plant-specific information and would be minimized to the extent feasible and limited to a maximum of 10 percent of the total system volume."[63] The preamble also seeks views "on an alternate approach that establishes a standard purge rate of 10 percent that can be adjusted upward or downward based on site-specific operating data."[64]

Cleco submits that EPA should allow permitting authorities to adopt one of three types of facility-specific alternatives to the proposed purge limitation. As noted above, the volume and spare capacity of high recycle rate systems can vary, with implications for the frequency or magnitude of discharge. This variation supports three possible facility-specific alternatives. Each of these three alternatives can ensure that all types of BATW handling systems remain equally protective of the environment. But they can also alleviate the harm to reliance interests engendered by the proposed definition of "primary active wetted bottom ash system." Some facilities have already incorporated impoundments into their closed-loop operations as part of their preparations to implement the 2015 rule, which had no equivalent term excluding impoundments. As a result, they have set the volume of their system to include the impoundments, and the proposed rule threatens to force a sudden, wrenching change to their systems to remove the impoundment from the loop or to purge an infeasibly low amount of the system's true volume (i.e., only 10% of the piping and primary tanks).

First, where a facility can establish relatively infrequent purges, particularly as the result of its preventive measures or system capacity, it should be granted additional flexibility to discharge above 10% total volume. This sliding scale approach can be calibrated by the permitting authority to remain as protective of the environment as the proposed rule while reducing the regulatory burden on some entities. In other words, reducing the frequency of discharges can reduce the total pollutants discharged to a level comparable to that of facilities with smaller volumetric capacity.

Second, where a facility uses a closed-loop system with a higher volumetric capacity (e.g., using an impoundment or a large number of "primary tanks"), the facility should be allowed to continue use of this system, but with the ability to discharge at less than 10% of the system volume. For example, Cleco preliminary estimates that one of its facilities using an impoundment could limit purges to less than 0.5% of the total volume. This alternative, too, might keep the aggregate pollutants discharged at levels equivalent to those of facilities with smaller volume, but it does so not by reducing the frequency of purges but the percentage allowed to be purged.

Third, permitting authorities should be allowed to substitute a site-specific BMP plan for a numeric volume percentage, based upon evidence from the permittee that it cannot reasonably comply with a 10% limit. The permitting authority would be empowered to collect a broad range of information, including historical precipitation data, component volumes, the BATW system's chemistry, metallurgy or properties of non-metallic components, operational and maintenance history, ash constituents and variation, and intersection with other processes (e.g., use as makeup water for FGD system). This information could give rise to any number of feasible BMPs to reduce the amount or frequency of purging needed.

[61] Id. at 64,636.
[62] Id.
[63] Id.
[64] Id.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 14

Comment Excerpt:

Under the proposed Option 2, EPA proposes "to allow facilities with a wet transport system, on an 'as needed' basis, to discharge up to 10 percent of the system volume per day on a 30-day rolling average to account for the challenges identified above, including infrequent large precipitation and maintenance events." Id. at 64635. GenOn supports this proposal. However, GenOn requests that the quench water added to the boiler hoppers be excluded from the discharge included in the 30-day rolling average. Metering of these flow inputs could be conducted and subtracted from the overall discharge.

Commenter Name: Eric C. Massey
Commenter Affiliation: Arizona Public Service Company
Document Control Number: EPA-HQ-OW-2009-0819-8324-A1
Comment Excerpt Number: 3

Comment Excerpt:

II. The Conditions Authorizing BATW System Purge Discharges Should be Clarified and Revised.

Generally speaking, APS supports the conditions EPA has proposed for the authorization of discharges from a well-designed and –operated BATW recirculation system, which contemplate discharges to address: (1) heavy precipitation events; (2) water balance maintenance regarding inflows of wastestreams other than BATW; (3) certain maintenance activities; and (4) managing system water chemistry to address pH, corrosiveness, and fine particles. That being said, certain of these conditions should be revised, along with the regulatory effects associated with utilizing these provisions:
1. Heavy precipitation events, especially those in the range of a 25-year, 24-hour event (as contemplated in Proposed § 423.13(k)(2)(i)(A)(1)), should not count towards the 10% discharge

cap in Proposed § 423.13(k)(2)(i)(B). In addition, the heavy precipitation events that trigger this condition should be expanded to include 10-year, 24-hour storm events. In both cases, severe rain is likely creating BATW recirculation system in-flows, which must be managed to ensure power plant reliability, but for which no amount of planning and preparation can properly address. As described in more detail in Part III, see below, EPA's proposal does not adequately account for the serious operational and system design challenges posed by precipitation events in the arid and semi-arid southwestern U.S., where the FCPP is located. In northwestern New Mexico, dense ground surfaces and extreme storm events exacerbated by climate change result in unpredictable precipitation events that can very quickly inundate BATW recirculation systems. Such inundating storm events, including both 25-year, 24-hour events and 10-year, 24-hour events, should not count toward the 10% cap on BATW system purge discharges in Proposed § 423.13(k)(2)(i)(B).

Commenter Name: Eric C. Massey
Commenter Affiliation: Arizona Public Service Company
Document Control Number: EPA-HQ-OW-2009-0819-8324-A1
Comment Excerpt Number: 4

Comment Excerpt:

2. Because permit writers under the EPA proposal must already evaluate a given power plant's BATW recirculation system in light of "control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice,"[5] there should be no need at all for the restriction on water balance purges based upon "regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water."[6] APS supports the UWAG proposal to simply restrict this discharge condition to maintaining water balance "consistent with system design." Such a condition allows proper consideration of appropriate BATW recirculation system design during permitting without extraneous complications.

[5] See, Proposed § 423.13(k)(2)(i)(B)
[6] See, Proposed § 423.13(k)(2)(i)(A)(2)

Commenter Name: Eric C. Massey
Commenter Affiliation: Arizona Public Service Company
Document Control Number: EPA-HQ-OW-2009-0819-8324-A1
Comment Excerpt Number: 5

Comment Excerpt:

3. Similarly, the maintenance-related purge condition contains unwarranted provisions concerning water volumes that cannot "be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment."[7] This language should

be deleted to avoid complicating what should otherwise be a simple condition: the authorization of discharges from maintenance-related system purges. As already mentioned, the permit writer already has discretion to ensure that power plants managing BATW through water recirculation maintain "control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice."[8]

[7] See, Proposed § 423.13(k)(2)(i)(A)(3)
[8] See, Proposed § 423.13(k)(2)(i)(B)

Commenter Name: Eric C. Massey
Commenter Affiliation: Arizona Public Service Company
Document Control Number: EPA-HQ-OW-2009-0819-8324-A1
Comment Excerpt Number: 6

Comment Excerpt:

4. Consistent with the UWAG comments, APS also supports modifying the BATW discharge conditions associated with water-chemistry management be amended for clarification purposes. As such, please: (a) eliminate reference to "installed equipment" in this condition (again based upon the overall technology evaluation implicated in the EPA proposal for BATW management), (b) replace "corrosive compounds" with "corrosive *substances*, (c) include reference to impacts upon BATW system *maintenance* in addition to system operations, and (d) ensure the list of chemistry conditions appropriate for management is disjunctive (i.e., "pH, corrosive substances, *or* fine particulates.") Making these changes would better align the condition with the realities of power plant operations and appropriately reflect the scope of permit-writer discretion when translating these provisions eventually into NPDES permit conditions.

Commenter Name: Eric C. Massey
Commenter Affiliation: Arizona Public Service Company
Document Control Number: EPA-HQ-OW-2009-0819-8324-A1
Comment Excerpt Number: 7

Comment Excerpt:

III. Heavy precipitation events, (as contemplated in Proposed § 423.13(k)(2)(i)(A)(1)), should not count towards the 10% discharge cap in Proposed § 423.13(k)(2)(i)(B).

EPA's regulatory threshold associated with precipitation events and the logic behind the assumption that facilities can merely "build their way out"[9] of issues related to such precipitation events are counter to the realities that face many regions of the United States, especially in the arid and semi-arid Southwest. As explained in the following Part, precipitation events (like those in Proposed § 423.13(k)(2)(i)(A)(1)) that can inundate BATW recirculation systems and threaten

EGU reliability, should not count towards the 10% cap on BATW recirculation system purge discharges authorized by Proposed § 423.13(k)(2)(i)(B).

As to heavy precipitation events, EPA has proposed that BATW discharges from high-recycle recirculation systems can be permitted: "To maintain system water balance when precipitation-related inflows within any 24-hour period resulting from a 25-year, 24-hour storm event, or multiple consecutive events cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment."[10] Although APS appreciates the effort that EPA has made to authorize the 10% allowance for BATW recirculation system blowdown, which will prove critical for the reliability of baseload power generation for APS, there are two fundamental, yet interrelated, misunderstandings that make this section related to precipitation events illogical and ultimately, unusable.

First, it is a mistake to focus on the precipitation event as the defining feature of the water flow (i.e. a 25-year, 24-hour event). In isolation a 25-year, 24-hour event may seem quantifiable, but when applied across each facility, it becomes rather arbitrary. A review of the lithology, pedology, and geology of the United States shows tremendous soil variability.[11] The region of the country and nature of the soils play significant roles in determining whether the precipitation will be absorbed or if there will be runoff. "Intense, local rainstorms are conspicuous summer features of the Sonoran Desert, and sparse vegetation, shallow soils, and high relief promote abrupt runoff that often results in severe floods (Plates 2, 3, Fisher and Minckley, 1978). Floods during summer of high unit rate and volume, with sharp crests and short duration (Burkham, 1976)." [12]

Therefore, it is important to realize that "flash floods are more common in arid regions than in humid regions, … In fact, in the typical continental type desert it's not uncommon to see rainfall amounting to five inches per hour. It may not last an hour, but the rate of accumulation is five inches per hour, and the heavy rain, of course, cannot readily infiltrate the dry soils."[13] As such, when the water cannot soak into the ground, it leads to greater quantities of stormwater runoff.[14] With respect to BATW recirculation systems, especially those operating in the arid and semi-arid southwestern U.S., EPA's ELG regulations must take this into account rather than focus solely upon rainfall quantity over a 24-hour period (e.g., the 25-year, 24-hour storm event in Proposed § 423.13(k)(2)(i)(A)(1)).

Additionally, the 25-year, 24-hour event may be sufficient when addressing steady rain events that can overwhelm a system over a 24-hour period. However, the 25-year, 24-hour event is not an adequate measure for more short and intense storm events. In other words, 1.9 inches over 24 hours is significantly different than 1 inch in 1 hour. Ground surface infiltration capacity is an essential element to managing large storm events. Too much rain, too fast upends a facility's ability to manage the event. "[I]f the rainfall rate exceeds the ground surface's infiltration capacity, surface runoff results. This process is called infiltration excess overland flow. The result is rapid and efficient surface runoff that can occur even during drought conditions."[15] As the National Oceanic and Atmospheric Administration notes, "[v]ery intense rainfall can produce flooding even on dry soil. In the West, most canyons, small streams and dry arroyos are not easily recognizable as a source of danger. A wall of water 10-15 feet high can scour a canyon suddenly."[16] If everything was predictably stable, a facility could engineer for extreme events.

Which leads us to the second, interrelated, misunderstanding that EPA makes with regards to precipitation events – not accounting for climatic changes. Climatic changes are reshaping the frequency, intensity and duration of weather events. A 2015 study, published in the Journal of Hydrology, provides the following conclusion: "Overall, a decrease in the total number of precipitation events was found, although with increased precipitation intensity, increased event duration, and higher soil saturation conditions for the 21st century. This combination could signify more hazardous conditions, with fewer precipitation events but higher rainfall intensity and over soils with higher initial soil moisture saturation, leading to more frequent occurrence of flash floods."[17] In fact, the study determined through two distributed hydrologic models, "the increase in flash flood occurrence frequency is on average between 30% and 40%."[18]

In the preamble, EPA asserts that "[j]ust as the EPA estimated costs of chemical additions in the 2015 rule to manage scaling, companies could … build storage tanks to hold water during infrequent maintenance or precipitation events."[19] Unfortunately, weather patterns are changing, with fewer precipitation events, but higher rainfall intensity leading to more frequent occurrence of flash floods. This is especially true in the southwestern U.S., where the FCPP operates in an environment where climate change is rapidly exacerbating the intensity of storm events and dense ground surfaces provide little mitigation against BATW recirculation system inundation. Accordingly, limiting discharges associated with heavy precipitation surge to the BATW recirculation system directly impacts a plant's reliability. Although we greatly appreciate EPA's efforts to provide reasonable operating parameters for the ELG rules and acknowledge that this may have been useful in the past, the realities of changing weather patterns require a new approach. We are no longer in a climate where a facility can reasonably and economically build bigger storage to protect against the need for heavy precipitation pass-through discharge. The changing nature of precipitation events (less frequent, but higher rainfall intensity) far exceeds our engineering capacity to plan for the duration and intensity of storms, directly impacting a plant's ability to ensure flexibility and reliability of the facility and the grid. To resolve this dilemma, we ask that EPA consider providing a separate allowance for heavy, inundating precipitation events that does not count towards the 10% cap on other BATW recirculation system purge discharges (i.e., to address plant water balance, system maintenance, and water chemistry).

[9] 84 FR 64635
[10] 84 FR 64620, 64674, Proposed 40 CFR §423.13(k)(2)(i)(A)(1)
[11] "The U.S. Soil Taxonomy classifies soils within a hierarchy of six categories. Only the highest-level category, order, is discussed here. Soil orders are named by adding the suffix -sol to a root word, as shown in the table of the U.S. Soil Taxonomy. The resulting 12 soil order names thus represent a classification based either on parent material or on processes related to the five factors of soil formation as reflected in diagnostic horizons." Encyclopedia Britannica Online Edition https://www.britannica.com/science/soil/Soil-classification
[12] *Impact of Flooding in a Sonoran Desert Stream, Including Elimination of an Endangered Fish Population (Poeciliopsis O. Occidentialis, Poeciliidae)*, James P. Collins, Craig Young, Judd Howell, and W.L. Minckley, Southwest Naturalist 26(4):415-423, November 20, 1981
[13] https://www.honolulu.hawaii.edu/instruct/natsci/geology/brill/gg101/Programs/program26%20WindDust/program26.html
[14] *See id.*
[15] Flash Flood Processes, http://kejian1.cmatc.cn/vod/comet/hydro/flash_flood/navmenu.php_tab_1_page_3.1.0.htm 2011, University Corporation for Atmospheric Research.

[16] https://www.nssl.noaa.gov/education/svrwx101/floods/ National Sever Storms Laboratory, Sever Weather 101 – Floods
[17] T*he character and causes of flash flood occurrence changes in mountainous small basins of Southern California under projected climatic change*, Theresa M. Modricka, Konstantine P. Georgakakos, Journal of Hydrology: Regional Studies 17 March 2015.
[18] *See id.*
[19] 84 FR 64635

Commenter Name: Patti Hershey
Commenter Affiliation: Lower Colorado River Authority (LCRA)
Document Control Number: EPA-HQ-OW-2009-0819-8317-A1
Comment Excerpt Number: 3

Comment Excerpt:

Ill. LCRA Concurs with EPA's Proposal to Exempt Rainfall from ELGs

LCRA concurs with EPA's proposal to authorize discharge of a specified volume of BA transport water due to certain large precipitation-related events as described in the Proposed Rule at§ 423.13 (k)(2)(i)(A). While the 2015 rule provided no exemption or allowance for discharges due to precipitation events, EPA recognized through feedback from utilities and trade associations that certain systems, such as some types of wet BA transport handling systems, often operate not as a fully closed loop system but as partially closed systems, allowing discharges associated with additional maintenance and repair activities, water imbalances associated with stormwater (rainfall events), and water chemistry imbalances. (84 Fed.Reg. at 64634, 64635 (Nov. 22, 2019)).

LCRA concurs with EPA's proposal to allow discharges when a facility has a wastewater system that is properly installed, operated, and maintained but may risk exceeding an effluent limit because of rainfall events that may occur back-to-back, or events with higher rates of accumulation beyond what the facility was designed to handle.

Commenter Name: Ed Stone
Commenter Affiliation: Maryland Department of the Environment
Document Control Number: EPA-HQ-OW-2009-0819-8464-A2
Comment Excerpt Number: 2

Comment Excerpt:

Additionally, EPA indicates in the Federal Register notice that "facilities should submit a calculation of the primary active wetted BA system volume ... excluding ... non-bottom ash transport systems that may direct process water to the bottom ash system." However, our experience with facilities in Maryland is that seal water and quench water (among other potential minor sources) are captured within the BATW system and would be very difficult to segregate for the purposes of a volumetric calculation. Yet EPA's pollutant analysis appears to consider only bottom ash transport water itself and proposes segregation of all other sources for the volumetric calculation. The Department requests further clarification as to how the 10% allowance for volumetric purges should be calculated and how this can be incorporated as a real-time, monitored, numerical permit limitation in the presence of other sources.

Commenter Name: American Coal Council (ACC)
Commenter Affiliation: American Coal Council (ACC)
Document Control Number: EPA-HQ-OW-2009-0819-8315-A1
Comment Excerpt Number: 3

Comment Excerpt:

ACC supports EPA's proposal to set BAT limits for BATW based on the use of dry handling or high recycle rate systems rather than dry handling or closed-loop systems proposed in the original 2015 ELG Rule. EPA's proposal also appropriately recognizes the need for a wet bottom ash transport system to have a discharge allowance of up to 10 percent of the system volume over a 30-day rolling average to account for operational needs and maintenance impacts and to provide flexibility in addressing site specific factors.

Commenter Name: American Coal Council (ACC)
Commenter Affiliation: American Coal Council (ACC)
Document Control Number: EPA-HQ-OW-2009-0819-8315-A1
Comment Excerpt Number: 4

Comment Excerpt:

EPA should also consider including an allowance for additional discharges beyond the 10 percent, 30-day rolling average to appropriately account for operational needs in 4 response to large scale storm events and natural disasters including floods and hurricanes, or other events that can overwhelm BATW systems.

Commenter Name: Caitlin McHale
Commenter Affiliation: National Mining Association (NMA)
Document Control Number: EPA-HQ-OW-2009-0819-8327-A1
Comment Excerpt Number: 4

Comment Excerpt:

III. Bottom Ash Transport Water

NMA also supports EPA's proposal to set BAT limits for BATW based on high recycle rate systems as the model technology, properly recognizing that wet bottom ash handling systems require periodic discharges known as "blowdown." These discharges are necessary to allow the release of buildup in the system and to prevent operational concerns in closed-loop wet bottom ash handling systems. The proposed rule authorizes operators to discharge up to 10 percent of the primary active wetted bottom ash system volume over a 30-day rolling average.[8] This discharge allowance also will provide flexibility in managing maintenance events. Additionally, EPA should consider including an allowance for additional discharges beyond the 10 percent 30-day rolling average where necessary to properly account for larger-scale, longer duration, or consecutive storm events. Due to the uncertainty associated with characterizing precipitation induced events at a nationwide scale, a potential method of addressing this concern is to *exclude* the volume of the precipitation event from the 10% volume allowance. Alternatively, a more reasonable precipitation event threshold, such as use of the 10-year 24-hour storm event, would allow more consistent compliance with this requirement. Similarly, when calculating the system volume, facilities should be allowed to *include* the volume of the installed spares, redundancies, and maintenance tanks. The need for system discharge is determined after installation and accounting for these redundancies and as such, the allowable discharge should incorporate their additional volume. This would allow facilities the necessary flexibility in maintaining available storage on these additional pollutant control measures.

[8] 84 Fed. Reg. 64675.

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 6

Comment Excerpt:

Buckeye supports the addition of a purge in the proposed rule. The proposal says facilities will be permitted to discharge up to 10% of the system volume per day on a rolling 30-day average. EPA should clarify this language to allow any type of discharge incidental to operating a partially closed wet ash system.

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 8

Comment Excerpt:

II. Facilities should be allowed to use facility-specific recycle rates as an alternative to the 10 percent 30-day rolling average for facilities operating a wet BA transport system and there should be no cap on discharges of BA system purges at a specific flow.

As an initial matter, EPA should clarify the language used in the preamble and the proposed rule to clearly distinguish between the terms "discharge" and "purge," as EPA seemingly uses them interchangeably which may lead to confusion when applied to real-world scenarios. Berkshire Hathaway Energy believes an appropriate distinction is that "discharge" indicates the flow of wastewater into a regulated waterbody, while "purge" indicates blowdown from a BA handling system.

EPA proposes allowing a wet transport system on an '"as needed"' basis to discharge up to 10% of the system volume per day on a 30-day rolling average or, alternatively, allowing a maximum of 10 percent of the total system volume to be purged.[2] EPA solicited comments on a facility-specific recycle rate alternative to the proposed 10% 30-day rolling average option for facilities operating a wet BA transport system,[3] as well as whether the discharges should be capped at a specific flow.

As EPA explains in its proposal, the option to discharge a percentage of the water from the BA handling system is intended for use during infrequent, large precipitation, and maintenance events. However, permitting authorities must have the ability to tailor each facility's permit due to climate variations, site-specific maintenance factors, characteristics of waste streams, source water, and the impact of large precipitation events on surface impoundments or dewatering basins, all of which differ across facilities, states, and regions. Given that the allowance for discharge is intended for use during abnormal events, maximum flexibility should be given to permitting authorities to allow for all potential factors that could impact a system on a site-specific basis.

Likewise, EPA should not cap the flow of purge water from BA handling systems because there may be scenarios where operators have limited control over the purge flows, or there may be a need to purge as quickly as possible to prevent spills or containment issues. In the event that a system purge occurs under the proposed rule, it is assumed that the facility will have taken proactive measures to prevent the discharge due to water chemistry and routine maintenance of the system. The two remaining factors that could initiate such a purge are high precipitation and equipment failure. In both cases, as discussed above, there may be limited operator control or a need to purge quickly to prevent spills or system contamination. Management of flows from a BA handling systems should be self-regulating, as each facility would be most familiar with the maximum flow possible from its BA handling system and would be able to size its treatment system accordingly.

2 Id. at 64,635-6.
3 Id. at 64,636.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)

Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 1

Comment Excerpt:

NRECA appreciates EPA's proposed revisions to the bottom ash transport water (BATW) limit and supports the proposed allowance of a 10% by volume 30-day rolling discharge allowance from recirculating BATW systems. This proposed change recognizes that such systems will need to discharge small amounts of BATW to accommodate exceptional precipitation events; to maintain system water balance; to conduct maintenance not otherwise exempted from the BATW definition; and to manage system water chemistry. NRECA also endorses UWAG's recommended modifications to the four proposed 423.13(k)(2)(i)(A)(1-4) conditions:

- Condition 1: Discharges due to precipitation events should not count against the 10% purge allowance. Rather, EPA should establish a separate precipitation event condition based on the 10- year, 24-hour storm event. We support the UWAG proposed language: "to maintain system water balance when precipitation-related inflows are associated with a 10-year, 24-hour or greater storm event, or an extended rainfall event or events within a rolling 7-day period, which cumulatively are equivalent to, or greater than, the 10-year, 24-hour storm event."
- Condition 2: Revise the condition to require plants "maintain water balance consistent with system design" since the system design and flow will be specified in the permit application. Such a revision will remove ambiguity from the plant and the permit writer to try and determine when it is or is not feasible to segregate certain wastewater streams from the BATW system.
- Condition 3: Limit the condition to "maintenance not otherwise exempted from the definition of transport water in 423.11(p)" to avoid confusion regarding what types of equipment constitute the model technology and how a permit writer should interpret the condition. The plant could be required to describe in the discharge log the type of maintenance necessitating the discharge.
- Condition 4: Amend the condition to "maintain system water chemistry when the system is unable to manage pH, corrosive substances, and/or fine particulates to below levels which impact system operation or maintenance." Such revisions will confirm that the condition encompasses different corrosion substances, not only chemical "compounds," and will reflect that these conditions may warrant maintenance before they actually affect system operations.

EPA has clearly outlined the components of model BATW technologies which are controlling. References to "additional installed spares, redundancies, equipment, or components" in proposed conditions 1 and 3 are unnecessary and creates unnecessary ambiguity about what is actually required by the rule.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)

Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 2

Comment Excerpt:

NRECA appreciates EPA's proposed revisions to the bottom ash transport water (BATW) limit and supports the proposed allowance of a 10% by volume 30-day rolling discharge allowance from recirculating BATW systems. This proposed change recognizes that such systems will need to discharge small amounts of BATW to accommodate exceptional precipitation events; to maintain system water balance; to conduct maintenance not otherwise exempted from the BATW definition; and to manage system water chemistry. NRECA also endorses UWAG's recommended modifications to the four proposed 423.13(k)(2)(i)(A)(1-4) conditions: • Condition 1: Discharges due to precipitation events should not count against the 10% purge allowance. Rather, EPA should establish a separate precipitation event condition based on the 10- year, 24-hour storm event. We support the UWAG proposed language: "to maintain system water balance when precipitation-related inflows are associated with a 10-year, 24-hour or greater storm event, or an extended rainfall event or events within a rolling 7-day period, which cumulatively are equivalent to, or greater than, the 10-year, 24-hour storm event." • Condition 2: Revise the condition to require plants "maintain water balance consistent with system design" since the system design and flow will be specified in the permit application. Such a revision will remove ambiguity from the plant and the permit writer to try and determine when it is or is not feasible to segregate certain wastewater streams from the BATW system. • Condition 3: Limit the condition to "maintenance not otherwise exempted from the definition of transport water in 423.11(p)" to avoid confusion regarding what types of equipment constitute the model technology and how a permit writer should interpret the condition. The plant could be required to describe in the discharge log the type of maintenance necessitating the discharge.

Condition 4: Amend the condition to "maintain system water chemistry when the system is unable to manage pH, corrosive substances, and/or fine particulates to below levels which impact system operation or maintenance." Such revisions will confirm that the condition encompasses different corrosion substances, not only chemical "compounds," and will reflect that these conditions may warrant maintenance before they actually affect system operations. EPA has clearly outlined the components of model BATW technologies which are controlling. References to "additional installed spares, redundancies, equipment, or components" in proposed conditions 1 and 3 are unnecessary and creates unnecessary ambiguity about what is actually required by the rule.

Commenter Name: Usha-Maria Turner
Commenter Affiliation: Oklahoma Gas and Electric Company (OG&E)
Document Control Number: EPA-HQ-OW-2009-0819-8290-A1
Comment Excerpt Number: 2

Comment Excerpt:

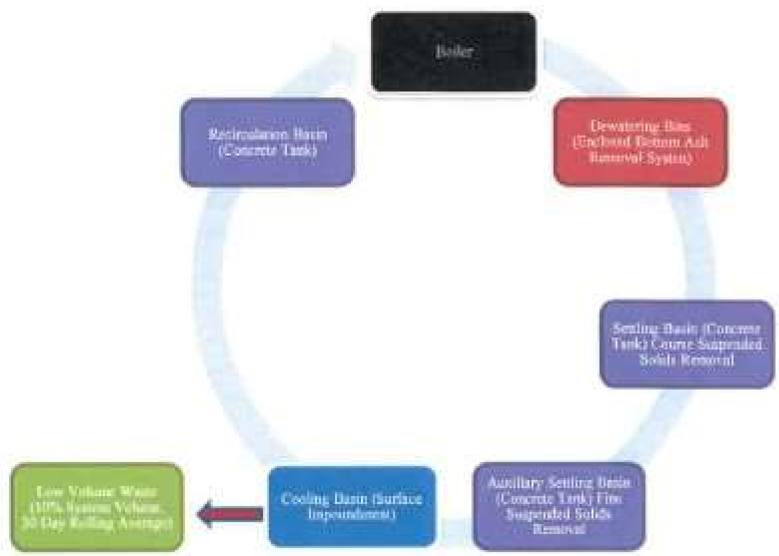
B. OG&E's Treatment Facilities Demonstrate That the Ten Percent Allowance is Both Necessary and Environmentally Protective

OG&E strongly supports EPA's proposal to revise the BATW limits to be based on high recycle rate systems and include 10 percent discharge allowance. This revision is crucial to the real-world operation of many BATW systems, including those at OG&E's Sooner and Muskogee facilities. The limited nature of the allowance also ensures that the revised BATW ELG remains environmentally protective.

OG&E's bottom ash transport wastewater handling systems are among those described by EPA as "generally ... zero discharge systems" that in some "cases must operate as high recycle rate systems."[5] OG&E utilizes multiple basins and impoundments to treat the used water, with the ultimate goal of reusing all of the water. For instance, at Sooner, the water travels from the boiler to dewatering bins, and then drains from the dewatering bins to a concrete settling basin. From the settling basin the water goes to a concrete auxiliary settling basin to let fine suspended solids settle out, and then the water is transported to an impoundment for cooling. From the cooling impoundment the water is pumped to the recirculation basin and back to the plant. The water is treated for pH and other chemical imbalances by injecting treatment chemicals into the bottom ash system. [6] Because all of the basins (except the dewatering bins) are open, the system operates as an open-air treatment system that allows for evaporation.

By utilizing this multi-step process, illustrated below, and once-through cooling on multiuse reservoirs and municipal, treated wastewater effluent, OG&E is able to treat and reuse water - - thereby minimizing the need for and use of new fresh surface or groundwater and enabling the facility to be more drought-tolerant in the Western state of Oklahoma.

Figure 1. Sooner Generating Plant:
Primary Active Wetted Bottom Ash Transport System Chart



As EPA acknowledges in the Proposed Rule, such systems may occasionally require limited purges or discharges for maintenance. For instance, when the evaporation rate is slow, a limited discharge may be required. Similarly, it may occasionally be necessary to add a limited amount of freshwater to the system for dilution, which may require a subsequent limited discharge at the back end (similar to cooling tower blowdown). Consistent with these standard operating practices, EPA is proposing to allow discharges of BATW of up to 10 percent of system volume on a 30-day rolling average. Discharges for maintenance are explicitly and appropriately contemplated in the Proposed Rule. See 84 Fed. Reg. at 64,674 (discharges authorized to "maintain water balance" and "to maintain system water chemistry").

The proposed revision is critical to the proper operation of wastewater handling systems, like those managed by OG&E, and can and will be managed in an environmentally responsible and protective fashion. First, the discharge allowance itself is fairly constricted both quantitatively - 10 percent - and qualitatively, as EPA identifies in proposed Section 423. l 3(k)(2), i.e. only when such discharges are authorized by permit. Second, any such discharge would be subject to effluent limitations and testing as low volume waste, after it has co-mingled with other low volume waste [7]. OG&E has been discharging BATW as part of its low volume waste stream since the facilities was put into service in the late 1970s. As a result, its low volume discharge outfall has repeatedly been evaluated as part of the multiple potential discharge screening tests which are required as part of the National Pollutant Discharge Elimination System permit and renewal process. Such tests ensure/demonstrate that facility outfalls are meeting technology-based effluent limitations as well as water-quality based effluent limitations.

[5] Proposed Rule, 84 Fed. Reg. at 64,635.

[6] The most common chemicals used in the treatment system are scale inhibitors, which are injected into the piping near the boiler. Other treatments can be done directly within the basins, for example, to remove suspended solids.
[7] Low volume waste water at OG&E includes water from water pretreatment, precipitator area runoff, laboratory drains, RO reject, boiler blowdown, sanitary waste, coal pile runoff, demineralizer waste, BATW and storm water.

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 5

Comment Excerpt:

America's Power supports this proposed change to correct this significant oversight in setting the discharge limitations for BA transport water under the 2015 ELG rule. The proposed change would set the discharge limitations based "high-recycle-rate systems" that would allow generating facilities using a wet BA transport system to discharge up to ten percent of the system volume per day on a 30-day rolling average.[10] Not requiring total elimination of all discharges is better aligned with the technical capabilities of the partially closed wet ash handling systems and will therefore set a reasonably achievable performance standard that will lower compliance costs while ensuring protection of human health and the environment.

However, we have concerns with one aspect of the proposed discharge limitation for BA transport wastewater. A purge rate of up to ten percent for the wet ash handling transport system would be permissible under the proposed rule for these recycle systems only if "reasonable active measures are insufficient to maintain system water chemistry or water balance within acceptable limitations, or to facilitate maintenance and repairs of the BA system."[11] This limiting language in EPA's proposal overlooks the practical fact that there is a wide range of operational scenarios in which it would be necessary to purge discharges in small quantities from wet ash handling systems. To correct this problem, EPA should revise the proposed discharge limitations to allow any type of discharges for short durations that are incidental to operating partially closed wet ash systems so long as the total volumetric amount of the discharges does not exceed ten percent of the system volume over a 30-day rolling average period.

10 84 Fed. Reg. at 64,635.
11 84 Fed. Reg. at 64,636. In particular, the proposed rule would allow the discharge of any BA transport wastewater up to the ten percent volumetric level for only one of following reasons: to maintain system water balance when precipitation-related inflows within any 24-hour period resulting from a 25-year, 24-hour storm event or multiple consecutive events cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment; to manage proper water balance when regular inflows from wastestreams other than BA transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is not feasible; to conduct maintenance not otherwise exempted from the definition of transport water when water volumes cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment; or to promote proper system water chemistry where current operations at the facility are unable to manage pH, corrosive compounds, and fine particulates to below levels that impact system operations. See 84 Fed. Reg. at 64,674.

Commenter Name: Mike Krumland
Commenter Affiliation: Nebraska Public Power District (NPPD)
Document Control Number: EPA-HQ-OW-2009-0819-8308-A1
Comment Excerpt Number: 7

Comment Excerpt:

NPPD also does not support the 10% rolling average discharge of bottom ash transport water. The 10% value has no basis and is therefore arbitrary. Bottom ash leachate tests indicate the that no current drinking water standards are exceeded for Arsenic, Barium, Boron, and Selenium, therefore, 100% of the bottom ash transport water should be allowed to be discharged.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 7

Comment Excerpt:

4. Table 3-4 of the Technology Development Document states that Plant Average Daily Discharge BATW Flow Rate is 1.73 MGD per plant. The proposed rule allows a purge (blowdown) of up to 10% which may be treated and discharged when necessary to maintain bottom ash system integrity.

As an alternative to a periodic purge, EPA should also allow a continuous purge of up to 10%, if the purge is treated and at least 90% of it reused in the bottom ash system. For example, 35 GPM can be treated with advanced vapor recompression to concentrate 1 GPM of brine and return 34 GPM of very clean water for BATW. Brine can be encapsulated for disposal in a CCR Landfill.

Thermal technologies, either alone or in combination with upstream membranes, can also be effective treatment for low volume, non-CCR wastewater and/or leachate that are currently combined with BATW for treatment.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 17

Comment Excerpt:

A. EPA Has Not Justified That the Proposed 10% Purge Allowance Is Needed.

EPA's record for the 2019 Proposal does not support a 10% purge limit. The principal basis for EPA's proposal is a 2018 report from the Electric Power Research Institute ("EPRI").[73] This report does not appear in the public rulemaking docket, but EPA's withholding of this report was in error, as it has already been made publicly available outside of this rulemaking.[74]

The 2018 EPRI Report documents "21 plants with existing or planned partially closed-loop systems" that reported challenges in achieving zero discharge using those systems.[75] EPRI provides no information as to how these 21 plants were chosen or whether they are representative of the industry as a whole. Moreover, the 2018 EPRI Report appears only to evaluate remote bottom ash recycling systems, meaning that no systems installed under the boiler were evaluated.[76] This provides an arbitrary basis for any EPA decision-making, as remote mechanical drag systems only account for 18 percent of bottom ash treatment systems.[77]

Although incorporating interviews from operators at 21 plants, the 2018 EPRI Report only analyzes data concerning potential purge volumes from 6 plants.[78] In addition, the 2018 EPRI Report notes that the purge volumes for these 6 plants are "based on estimates and calculations and were not measured . . . ."[79] In addition, EPA does not appear to know the identities of the 6 plants discussed by EPRI, and EPA has not done any independent analysis of those plants to evaluate what the EPRI report says about them or whether these 6 plants are representative of the industry as a whole (much less the best-performing plants in the industry).[80]

Even taking the 2018 EPRI Report at face value, it does not support the 2019 Proposal's 10% purge allowance. As EPA itself acknowledges, the 2018 EPRI Report at most supports a 0-2% monthly volumetric purge allowance in a typical month, and only identifies the possibility of an infrequent event, such as a major storm event or system maintenance, occurring in any given month as a possible justification for a higher purge allowance.[81] Yet EPA's proposed 10% purge allowance is based on the possibility that both a major maintenance event and a major precipitation event[82] – both of which are likely very infrequent, occurring less than once per year –would occur in the same month.[83] And although the probability of both of these types of events occurring in the same month is extremely low, plants would be able to take advantage of the 10% purge allowance every single month that they operate, regardless of whether such events actually occur.[84] Nor does the 2019 Proposal require plant operators to submit any certifications or documentation concerning the occurrence of any of the specific events that EPA claims purportedly necessitate such purges – which means that the 2019 Proposal would allow the purge of three times the entire volume of a plant's bottom ash system each month, regardless of whether there is any legitimate need for such discharges. This is arbitrary and capricious.[85]

[73] EPRI, Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges (2018) ("2018 EPRI Report") (attached).
[74] See Interim Release 2, Part 1, Document No. ED_002364A_00000950-00001 of the publicly available responses to FOIA-EPA-HQ-2019-001328, https://foiaonline.gov/foiaonline/action/public/search/quickSearch?query=EPA-HQ-2019-001328.
[75] 2018 EPRI Report at 1-2.
[76] Id. at v, vii.
[77] ERG, Pollutant Loadings Associated with Current Discharges of FDG Wastewater and Bottom Ash Transport Water – DCN SE07214, at Tbl. 2, Docket ID No. EPA-HQ-OW-2009-0819-7836 (July 15, 2019).
[78] Id. at 1-2, 1-7.
[79] Id. at 1-2. Another flaw in the EPRI reports that EPA has adopted in the 2019 Proposal is that there are

insufficiently clear limits on plant operator's calculations of the maximum volume of the bottom ash system for the purpose of defining the 10% purge allowance. See Dr. Ranajit (Ron) Sahu, Technical Comments on EPA's Proposed Rule to Revise the Best Available Technology (BAT) Effluent Limitations Guidelines (ELGs) for Flue Gas Desulfurization (FGD) Wastewater and Bottom Ash Transport Water (BATW), at 10-11 ("Sahu Expert Report") (attached). EPA describes this as the "hypothetical maximum volume," 84 Fed. Reg. at 64,633, and the proposed regulatory language defines this as the "primary active wetted bottom ash system volume," to include "the maximum volumetric capacity of bottom ash transport water in all piping (including recirculation piping) and primary tanks" but not "installed spares, redundancies, maintenance tanks, other secondary bottom ash system equipment, and nonbottom ash transport systems," id. at 64,672 (proposed 40 C.F.R. § 423.11(aa)). Within these limits, plant operators will have discretion to define the size of their tanks, piping, etc., in the first instance, which is a significant loophole that would likely be used by plant operators to increase the size of their 10% purge allowance. See Sahu Expert Report at 10-11.

[80] See id. at 10.

[81] 84 Fed. Reg. at 64,663; see also Proposed TDD at 8-23 to 8-24; 2018 EPRI Report at 1-8 to 1-2.

[82] In addition, neither the 2018 EPRI Report nor the 2019 Proposal acknowledge that what constitutes a major precipitation event can vary from place to place; in some places, even major storm events can be significantly smaller than in other places. The calculations presented by EPRI (and adopted uncritically by EPA) fall to take this into account and are thus arbitrary for this reason as well.

[83] See 84 Fed. Reg. at 64,664 Tbl. XIV-2; see also Proposed TDD at 8-23 to 8-24.

[84] See Sahu Expert Report at 12.

[85] See id.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 18

Comment Excerpt:

The 2019 Proposal is also arbitrary and capricious because EPA has failed to consider whether bottom ash system purges due to precipitation can be eliminated by modifications to the design or placement of the system. For example, there is nothing in the record that evaluates whether precipitation inflows into bottom ash recycling systems can be avoided by covering portions of the system that might be exposed to such inflows or taking other commonplace measures (grading, curbing, etc.) to direct stormwater away from bottom ash recycling systems.[86] It is longstanding EPA policy that stormwater not be permitted to commingle with polluted wastewater (thereby further spreading the contamination) whenever it is feasible to keep it separate.[87] Neither the 2019 Proposal, nor the EPRI report upon which the proposed bottom ash purge allowance is based, addresses this issue at all. EPA's failure to do so is arbitrary and capricious.

In addition, the 2019 Proposal would allow power plants to operate in a manner that is not consistent with EPA's own permits and policies concerning industrial stormwater, and is unlawful, arbitrary, and capricious for that reason as well. For example, EPA's multi-sector general permit for industrial stormwater provides that facilities, including power plants, "must minimize the exposure of manufacturing, processing, and material storage areas (including loading and unloading, storage, disposal, cleaning, maintenance, and fueling operations) to rain, snow, snowmelt, and runoff in order to minimize pollutant discharges by either locating these industrial materials and activities inside or protecting them with storm resistant coverings."[88]

Further, "[u]nless infeasible," facilities must "[u]se grading, berming or curbing to prevent runoff of contaminated flows and divert run-on away from these areas," and also "[l]ocate materials, equipment, and activities so that potential leaks and spills are contained or able to be contained or diverted before discharge."[89] Power plants in particular are required to minimize contamination of surface runoff from areas adjacent to disposal ponds, landfills, and other areas of the site where process waters are handled.[90] The 2019 Proposal appears to assume, however, that power plants should not be required to follow these basic, longstanding principles of responsible stormwater management.

[86] See id. at 12-13.
[87] See id.
[88] EPA, National Pollutant Discharge Elimination System (NPDES) Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity (MSGP), § 2.1.2.1 (June 4, 2015), https://www.epa.gov/sites/production/files/2015-10/documents/msgp2015_finalpermit.pdf (attached).
[89] Id.
[90] Id. at Part 8, Subpart O.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 19

Comment Excerpt:

With respect to purge discharges due to maintenance events, the 2019 Proposal is also arbitrary and capricious. EPA does not appear to have considered that, during maintenance events, bottom ash transport water could be collected in storage tanks for later recycling or treatment rather than discharged.[91] This is especially true for the vast majority of plants that have wet or dry FGD systems available to utilize the bottom ash purge stream, if managed using storage tanks.[92]

[91] See Sahu Expert Report at 13.
[92] Id.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 20

Comment Excerpt:

Similarly, the 2019 Proposal is arbitrary and capricious because EPA does not appear to have considered the possibility that routine or minor leaks from bottom ash recycling systems could be managed consistent with the 2015 ELG Rule[93] or eliminated. For example, leaks from pump seals can be eliminated using seal-less technologies, whereas other leaks could be eliminated through timely regular maintenance.[94] In addition, "[t]o the extent that that scaling or corrosion conditions can exacerbate leaks, simple treatments such as pH balancing and using of anti-scaling inhibitors can be used."[95]

[93] As EPA notes in the 2019 Proposal, see 84 Fed. Reg. at 64,634, the 2015 ELG Rule excludes from the definition of bottom ash transport water "low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping) or minor maintenance events (e.g., replacement of valves or pipe sections)." 40 C.F.R. § 423.11(p).
[94] See Sahu Expert Report at 13-14.
[95] Id. at 14 (citing 84 Fed. Reg. at 64,636).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 21

Comment Excerpt:

In sum, EPA's record for the 2019 Proposal does not demonstrate that a 10% bottom ash purge allowance is needed at *any* plant, let alone the best-performing plants in the industry. As discussed above, the 2018 EPRI report relied on by EPA only looks at remote systems, fails to adequately characterize the industry as a whole, and fails to evaluate available, feasible methods for eliminating discharges of the bottom ash purge stream, and yet EPA adopts its findings uncritically without any independent analysis or further data collection. The 10% purge allowance lacks sufficient justification in the record, and any final rule containing such an allowance would be arbitrary and capricious.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 23

Comment Excerpt:

B. The Proposed 10% Purge Allowance Is Contrary to the BAT Standard, Because It Is Not Based on the Performance of the Best-Performing Plant.

Even if EPA had presented a sufficient record for the 2019 Proposal that the 10% bottom ash purge allowance was needed at *any* power plants (which it has not), EPA cannot lawfully determine that a bottom ash purge allowance is BAT for the industry as a whole. Numerous plants are already achieving zero discharge of BATW through use of either fully closed loop recycling or dry handling systems. As EPA found in 2015, both such systems are affordable, readily available options for eliminating bottom ash discharges. Plainly, the best-performing plants in the industry are achieving zero discharge, and nothing in EPA's record requires reversal of its 2015 BAT determination. The 2019 Proposal is thus contrary to well-established law on BAT, and arbitrary and capricious for this reason as well.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 29

Comment Excerpt:

3. EPA has not justified that a 10% purge allowance reflects the performance of the best-performing plant.

...

In addition, as noted above, EPA has based the proposed 10% purge allowance on reports from EPRI that only evaluate data from 6 plants, the data that they analyze is only estimated, not directly measured, and EPA does not appear to have done anything to learn the identities of the 6 plants, independently evaluate EPRI's information about them, or determine whether they are representative of other plants in the industry (much less the best-performing plants, as BAT requires).[119] EPA's failure to develop this record to be able to make specific findings that a 10% purge allowance would be needed at the best-performing plants in the industry makes it unlawful for EPA to determine that a 10% purge allowance reflects BAT. The EPRI reports do not provide a sufficient basis for EPA to determine BAT, there is no other information in the record to support such a determination, and any such determination by EPA would be arbitrary and capricious because of the deficiencies in those reports and EPA's failure to collect its own data or do an independent analysis of the plants discussed by EPRI.

[119] See Sahu Expert Report at 9.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 9

Comment Excerpt:

1.4 EPA's Definition of 10% Volumetric Purge is Poorly Defined and Unsupported

I have reviewed the preamble to the proposed rule and its accompanying Technical Development Document (TDD)[17] in order to understand how EPA is defining its proposed 10% volumetric purge of BATW.

First, in the preamble, EPA states:

"…the high recycle rate system being selected as BAT allows for a 10 percent purge of the system volume each day…"[18]

EPA also states:

Under the proposed option, the EPA would allow facilities with a wet transport system, on an ''as needed'' basis, to discharge up to 10 percent of the system volume per day on a 30-day rolling average to account for the challenges identified above, including infrequent large precipitation and maintenance events. The EPA proposes that the term ''30-day rolling average'' means the series of averages using the measured values of the preceding 30 days for each average in the series…[19]

Later in the preamble, EPA states:

"As explained in Section VII.b.ii, for those facilities using high rate recycle systems, the EPA proposes to allow a discharge up to 10 percent of the system volume per day on a 30-day rolling average…"[20]

Next, I turn to EPA's explanation for how it arrived at this 10% purge rate allowance and what it includes. The sum total of EPA's basis and methodology is summarized in the following excerpted paragraphs from the preamble, as discussed under B.1:

…the EPA is proposing a pollutant discharge allowance in the form of a maximum percentage purge rate for BA transport water. To develop this allowance, the EPA first collected data on the discharge needs of the model treatment technology (high recycle rate systems) to maintain water chemistry or water balance (footnote omitted). EPRI (2016) presents discharge data from seven currently operating wet BA transport water systems at six facilities. These facilities were able to recycle most or all BA transport water from these seven systems, resulting in discharges of between zero and two percent of the system volume. The EPA's goal in establishing the proposed purge rate was to provide an allowance to address the challenges that would be incorporated in the EPRI (2016) data, as well as infrequent precipitation and maintenance events, the EPA also needed a way to account for such infrequent events. While EPRI (2016) noted that infrequent discharges happened at some facilities, it did not include such events in its discharge calculations. As a result, EPA looked to EPRI (2018), which presents hypothetical maximum discharge volumes and the estimated frequency associated with such infrequent events for currently operating wet BA systems (footnote omitted). Since these calculations are only estimates…[21]

For purposes of calculating the allowance percentage associated with such infrequent events, the EPA divided the discharge associated with an estimated maintenance and precipitation event <u>by the volume of the system</u>, and then averaged the resulting percent <u>over 30 days</u> (emphasis added). Finally, the EPA added each reported regular discharge percent from EPRI (2016) to the averaged infrequent discharge percent under four scenarios: (1) With no infrequent discharge event, (2) with only a precipitation-related discharge event, (3) with only a maintenance-related discharge event, and (4) with both a precipitation-related and maintenance-related discharge event. These potential discharge needs are reported in Table XIV–2 below. Consistent with the statistical approach used to develop limitations and pretreatment standards for individual pollutants, the EPA selected a 95th percentile of 10 percent of total system volume as representative of the 30-day rolling average (footnote omitted)…[22]

While there were further decimal points for the actual calculated 95th percentile, the EPA notes that 10 percent is two significant digits, consistent with the limitations for FGD wastewater pollutants. Furthermore, a 10 percent volumetric limit will be easier for implementation by the permitting authority as it results in a simple decimal point movement for calculations.[23]

I also show below, EPA's summary Table XIV-2 from the preamble discussing the 6 plants used in its analysis.[24]

TABLE XIV–2—30-DAY ROLLING AVERAGE DISCHARGE VOLUME AS A PERCENT OF SYSTEM VOLUME[a]

Infrequent discharge needs as estimated in EPRI (2016)		Regular discharge needs to maintain water chemistry and/or water balance as characterized in EPRI (2016)						
Type of infrequent discharge event	30-Day rolling average (%)	Facility A (%)	Facility B (%)	Facility C (%)	Facility D (%)	Facility E (%)	Facility F—System 1 (%)	Facility F—System 2 (%)
		0.1	0.0	1.0	0.0	0.8	2.0	2.0
Neither Event	0.0	0.1	0.0	1.0	0.0	0.8	2.0	2.0
Precipitation Only	5.4	5.5	5.4	6.4	5.4	6.2	7.4	7.4
Maintenance Only	3.3	3.4	3.3	4.3	3.3	4.1	5.3	5.3
Both Events	8.7	8.8	8.7	9.7	8.7	9.5	10.7	10.7

[a] These estimates sum actual/reported, facility-specific regular discharge needs with varying combinations of hypothetically estimated, infrequent discharge needs.

It is also worth noting the following comment in the preamble:

"For example, in the table above [Table XIV-2], only when the Facility F systems experience both high-end precipitation- and maintenance-related discharge events could the required discharge potentially exceed the 30-day rolling average of 10 percent."[25]

With the above context and background, I discuss the following shortcomings with EPA's basis for the proposed 10% purge allowance if any allowance is needed at all.

<u>First</u>, it is worth noting that EPA has relied upon just two related industry studies – noted as EPRI (2016) and EPRI (2018)26 in the preamble excerpts above. Neither of these documents is provided in the public rulemaking record, thus making a mockery of EPA's many requests in the preamble that the public provide comments on various aspects of EPA's proposal. Nonetheless, I have reviewed the second of these two documents, noted as EPRI (2018), which has been made publicly available outside of the rulemaking record. I also note that EPRI (2018) clearly states that purge volumes included in this report are "…based on estimates and calculations and were not measured…"[27] Further, much of EPRI (2018) includes unsupported or speculative statements.[28]

<u>Second</u>, as EPA notes in the preamble, and as summarized in Table XIV-2, the entire analysis is based on data by EPRI for just 6 plants – none of which are actually identified in EPRI (2018) –

and likely not identified in EPRI (2016) as well. In fact, Table XIV-2 uses the same letter designations A through F to identify these plants, as is done in EPRI (2018). It is clear that EPA does not know which plants are represented as A through F. Crucially, therefore EPA has no idea as to whether these six plants are representative of the entire class of coal-fired power plants in the U.S., much less whether these plants represent the best performing plants – as is required under the BAT standard. In fact, it is more likely than not that these six plants represent the worst performing plants, who simply volunteered to provide their data to EPRI. In any case, it is my opinion that by not identifying these plants and by not showing that they are the representatives of the best performers in the class of plants that EPA is attempting to address, that EPA's entire proposal is plainly unsupported.

Third, and following from above, EPA's proposal is not based on any EPA-collected (and publicly-available) data, as summarized in Table XIV-2 shown above.

17 See generally TDD.
18 84 Fed. Reg. at 64,630 n.14.
19 Id. at 64,635.
20 Id. at 64,644.
21 84 Fed. Reg. at 64,663.
22 Id. at 64,663 n.99.
23 Id. at 64,663.
24 Id. at 64,664.
25 84 Fed. Reg. at 64,664.
26 EPRI, Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges, (Sept. 2018).
27 EPRI (2018) at 1-2.
28 As examples:

- - at page v, EPRI states that the study evaluated 21 plants. But there is no discussion as to how these plants were chosen and whether and how they are representative of the best performing plants in the coal-fired fleet;
- - at page 1-2, the EPRI report admits that "purge volumes from bottom ash systems…are based on estimates and calculations and were not measured." No calculations are provided in the report. To the extent that the authors used "estimates," it is not clear how such estimates were made and using what data, if any;
- - at page 1-2, in relation to the use of sulfuric acid as one means of pH control to avoid scaling, the report states that "…if the sulfuric acid demand is high enough, or is concentrated in the closed-loop via evaporation, then calcium sulfate (another scalant) could theoretically form…" (emphasis added). The report provides no basis for the statement that sulfuric acid would continue to concentrate as a result of evaporation of the water, presumably with no evaporation of the aqueous acid also;
- - at page 1-3, the report speculates on the presence of aluminum in BATW and how that "can negatively impact scrubber operations (e.g., aluminum-fluoride blinding) or gypsum water quality…" without providing any technical support whatsoever;
- - at page 1-3, the report states that "[p]lants with dry FGD systems may still have water demand but it is likely less than the purge volume needed" (emphasis added);
- - at page 1-3, the report states that "[t]reatment of purge water could cost millions of dollars, such as for reverse osmosis, evaporation, crystallization, etc., to eliminate water that fails loop chemistry requirements" (emphasis added). It is not clear why EPRI could not collect actual data on how its member companies are managing "water that fails loop chemistry requirements" and what amounts they are spending on this management;
- - at page 1-3, the report states that "[p]urges for bottom ash system maintenance events such as emptying major equipment could coincide with FGD scrubber outages…" (emphasis added). Of course the report does not discuss how such scheduling could be easily avoided, thereby avoiding the need for any additional steps beyond sending the BATW purge to the FGD, as allowed in the 2015 rule.

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Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 10

Comment Excerpt:

Fourth, as noted in EPA's discussions, the 10% purge allowance is based on the "volume of the system." EPA does not define what this exactly means in the preamble or the rule.[29] A straightforward reading of this implies that total volume of whatever a plant operator considers to be its BATW system including piping, tanks, clarifiers, etc. I have reviewed EPRI (2018) and the stated "volumes" in that report are not based on any calculations for the six plants considered, as I have noted above. They are simply guesses. Crucially, by allowing the 10% purge water volume to be based on the "volume of the system" EPA has set up a perverse incentive to maximize the volume of the BATW system – regardless of the amount of water that the bottom ash handling system requires. In fact, in the preamble EPA describes them as "hypothetical maximum discharge volumes."[30] It is not inconceivable that if an operator can simply increase the volume of the BATW system, say, by installing an oversized tank, it can therefore discharge a higher quantity of purge water, since the 10% purge volume will be based on this higher system volume. This makes no sense. In effect, EPA's proposal allows for a loophole that can and will be abused. Even if there is a need for a 10% purge rate, which there is not as I discuss in this section, EPA should base it on the actual water volume in the BATW system and not the "system" volume or the "hypothetical maximum" volume.

29 The closest EPA comes to discussing this is in Section 5.3.3 of the TDD: "[B]ased on industry-provided data, the EPA estimated the daily slipstream flow rate to be 10 percent of the primary active wet bottom ash system volume (i.e., the plant-level volume associated with the bottom ash hoppers, rMDS, sluice pipes, and surge tanks, but not installed spares, redundancies, maintenance tanks, or other secondary bottom ash system equipment not used on a daily or near-daily basis)." TDD at 5-46. However, simply stating that the volume includes "…bottom ash hoppers, rMDS, sluice pipes, and surge tanks…" is not sufficient. It is also vague. For example, it is not clear why the hoppers or the sluice pipes (which are, by definition closed) should be included in this calculation since they cannot allow precipitation to enter.
30 84 Fed. Reg. at 64,663.

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Comment Excerpt Number: 11

Comment Excerpt:

Fifth, use of a 30-day rolling average is arbitrary. As EPA notes, and as shown in Table XIV-2, EPA's basis for the 10% purge rate includes continuous or routine purges, which EPA suggests are between 0 and 2%[31] for these 6 plants along with occasional purges (i.e., precipitation and system maintenance) which, by definition are not frequent. As EPA notes, its precipitation estimates are based on 25-year events.[32] And the record, including EPRI (2018), clearly shows that major system maintenance is only needed at most once per year or even less frequently[33] – i.e., drag chain replacement every 3 to 5 years or so depending on the type of system.[34] Given this, using a 30-day rolling average that includes events with frequencies of once per year up to once per 25 years, makes little sense.

Simple math shows that an operator can discharge 3 times the "system volume" of BATW in a 30-day period and still meet the 10% purge volume limitation – i.e., 10% of the volume each day. This is more than generous[35] and simply unnecessary. It is a recipe for abuse. Even the EPRI (2018) report does not support a 10% purge allowance on a 30-day rolling average basis.

31 See TDD Section 8.4, referencing EPRI (2016).
32 84 Fed. Reg. at 64,636 n.45.
33 EPRI (2018) at 1-2: "Intermittent purges represent maintenance events that generally occur annually, or less frequently, such as emptying the entire closed-loop system or dewatering equipment for maintenance or inspection." See also Table 1-2 in EPRI (2018) which shows such frequencies as annual or less.
34 See ERG Memorandum Re: Methodology for Estimating Bottom Ash Transport Water Compliance Costs for the Proposed Revisions to the Steam Electric ELGs (Aug. 29, 2019) (EPA-HQ-OW-2009-0819-8160). For MDS, "ERG estimated 3-year recurring costs associated with MDS drag chain replacement. The drag chain is the component of the system that drags the bottom ash from the water bath, up the incline to intermediate storage. Based on vendor data collected during the development of the2015 rule, this chain should be replaced every three years…" Id. at 5-6. For rMDS, "ERG estimated 5-year recurring costs associated with rMDS drag chain replacement. Based on vendor data collected during the 2015 rule, this chain should be replaced less frequently for rMDS compared to MDS, every five years…" Id. at 9.
35 I note that even operators with supposed difficulties in dealing with BATW purges, such as NIPSCO (discussing its Bailly plant), which has a dry FGD, asked for flexibility "…to discharge no more than one BATW system volume, no more than one time per calendar year…" See Email Correspondence of Nicholas Dernik, NIPSCO, and Richard Benware, EPA, Re: NIPSCO Follow-up from ELG Data Submission Meeting (June 2018) (EPA-HQ-OW2009-0819-8275).

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Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 13

Comment Excerpt:

Seventh, as confirmed by Table XIV-2, the majority of EPA's 10% purge volume allowance is due to precipitation.[36] Comparing the 'Precipitation Only" and "Both Events" lines for each of the plants shown in the table, we see that the precipitation contribution, in percent, is as follows: Facility A (63%); Facility B (62%); Facility C (66%); Facility D (62%); Facility E (65%); Facility F, System 1 (69%); and Facility F, System 2 (69%). Allowing discharge of what is predominantly precipitation contaminated by process water is simply inconsistent with BAT and common sense. It is not rocket science to design and place the BATW recycle system to avoid rain/snow intrusion into the BATW system. Simply covering those portions of the system solves the problem. Placing the system in an area suitably graded to avoid stormwater, followed by including any potentially exposed portions under cover – such as in a maintenance shed – solves this problem. As EPA is well aware, there are numerous covered structures in any power plant –

including maintenance sheds, tool sheds, spare parts sheds, and many others. It is not clear why exposed BATW components cannot also similarly be covered. This alone, even by EPA's unsupported calculations, will eliminate well over half (i.e., 62-69%) the required purge volume.

Eighth, and related to the above, EPA's inclusion of precipitation in its purge volume allowance runs counter to EPA's long-standing policies requiring that stormwater and process waters not be commingled and that they be handled separately. For example, this is the basis for most Storm Water Pollution Prevention Plans (SWPPPs) – which require Best Management Practices precisely to avoid stormwater contact with process waters.[37] In addition, for at least the last two decades, EPA has been requiring municipalities throughout the country to separate stormwater and municipal wastewater (i.e., so-called combined sewer overflows), at great taxpayer expense. It is therefore surprising and indefensible to see EPA include precipitation as part of the purge volume calculation – thereby discouraging operators from taking entirely reasonable and common-sense steps to shelter BATW systems from precipitation.

I note that even EPRI (2018) explicitly recognizes[38] that precipitation can be eliminated as a factor if equipment is covered or enclosed in buildings. Please see my later discussion on Best Management Practices, where I include suggestions for mitigation of purge waters taken from EPRI (2018).

Ninth, as noted above, EPA provides no reason why any waters that need to be handled due to infrequent maintenance – such as from chain replacements and the like – cannot simply be accommodated in storage tanks – and then gradually bled to FGDs or boiler feedwater, with nominal treatment, if and as needed. EPA does not consider or discuss this common sense approach.

My analysis shows that the vast majority of the 90 or so plants that EPA is addressing via this proposed rule (i.e., the approximately 25% of the fleet that are the laggards) already have wet or dry FGD systems for SO2 air pollution control. Both wet and dry FGD systems require significant quantities of water to make the reagent slurry which is then used to remove SO2 from the flue gases from the units at the plant. The 2015 rule specifically allows BATW water to be recycled into the FGD, and many plants already handle their BATW purge in this way. There is simply nothing in the record to justify that this is not a technically feasible route for managing any maintenance purge from BATW systems, for both types of FGDs.[39] On the contrary, the fact that this is how many plants are handling BATW purge demonstrates that EPA inexplicably overlooked an obvious and safer manner of handling any purge generated by infrequent maintenance events.

Tenth, compounding these problems in its analysis, EPA bases the 10% purge rate on the possibility that precipitation and major maintenance, both infrequent events, may simultaneously occur. (see the last line on Table XIV-2). This, coupled with the fact that an operator need not show that either of these events have actually transpired in order to take advantage of this purge rate simply means that EPA is proposing nothing more than a loophole, inviting operators to game the system.

Eleventh, as to the routine purges, which EPA has estimated at 2% based on the six EPRI plants, even those can be handled or eliminated under the current, 2015 rule. First, sources of these routine purges, such as leaks from pump seals, etc. can be eliminated using seal-less technologies.[40] Other minor leaks are preventable with routine and ongoing maintenance. To the extent that scaling or corrosion conditions can exacerbate leaks, simple treatments such as pH balancing and using of anti-scaling inhibitors can be used.[41] All of these and additional steps can and should be part of a Best Management Practices plan required at all plants (and not just the plants with low generation, as EPA has proposed).[42] And, finally, of course, any remaining purges, much smaller than even 2% can be utilized in the FGDs or boiler feedwater.

For all these reasons, it is my opinion that zero discharge of BATW, as required by the current, 2015 rule is entirely feasible, can be done, is being done, and is BAT for these wastewaters. Allowing a technically unsupported and improperly constructed 10% volumetric purge allowance with no consideration of even reasonable engineering approaches (such as covers and storage) that could render this unnecessary, as EPA has proposed, is indefensible.

36 EPA confirms that including precipitation is challenging: “Two considerations make determining a nationwide BAT for these discharges challenging and fact-specific. First, in the case of precipitation or maintenance-related purges, such purges would be potentially large volumes at infrequent intervals.45” 84 Fed. Reg. at 64,636. “In the case of precipitation, rainfall exceeding a 25 year, 24- hour event may only happen once during the 20-year lifetime of the equipment, if at all.” Id. at 64,636 n.45.
37 This is based on my consulting experience for over 30 years. The goal in managing stormwater is to first avoid contaminating it in the first place – i.e., avoiding contact between process and storm waters to the maximum extent possible.
38 See EPRI (2018) at 1-4, Table 1-1.
39 For example, NIPSCO, which operates dry FGDs, simply states that “[i]t would not be appropriate to expect those facilities to introduce a waste stream, BATW, into a Dry FGD that was not designed to manage that type of waste stream.” Yet NIPSCO fails to provide any technical reasons why this might be so or why, with minor treatment, BATW could not be used in dry FGD systems. See Email Correspondence of Nicholas Dernik, NIPSCO, and Richard Benware, EPA, Re: NIPSCO Follow-up from ELG Data Submission Meeting (June 2018) (EPA-HQ-OW2009-0819-8275).
40 See, for example: http://www.tmagpumps.com/mag-drive-pump-wastewater/; https://www.chemicalprocessing.com/articles/2017/select-the-right-sealless-pump/; https://www.pumpsandsystems.com/pumps/water-wastewater-treatment; https://www.pumpsandsystems.com/pumps/water-wastewater-treatment and, literally, thousands of similar manufacturers and applications.
41 In fact, EPA recognizes this as such:
Under such an alternative, each facility operating a high recycle rate system would take proactive measures (e.g., acid or caustic addition for pH control, chemical addition to control alkalinity, polymer addition to remove fines) to maintain system water chemistry within control limitations established by the facility in a BMP plan similar to that proposed for low utilization units… 84 Fed. Reg. at 64,636. See also, EPRI (2018) at 1-5 – 1-6, Table 1-1.
42 Id.

21b BATW – High Recycle Rate – Costs and Loads

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Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 117

Comment Excerpt:

A. EPA's Analysis of Economic Impacts Should Reflect the Actual Costs of All of the Technologies and Procedures Contemplated by the BATW Options under Evaluation.

In Section X, UWAG discusses EPA's technology cost estimates for bottom ash and provides information on the costs of some of the additional components that Option 2 as currently proposed appears to anticipate, but for which EPA has not included costs. These include installed spares, redundancies, maintenance tanks, other secondary bottom ash system equipment; control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice; and BPJ requirements for BATW purge.

As demonstrated in those comments, and in reports submitted by EPRI,[240] the actual costs of technologies required or potentially required to comply with Option 2 are considerably higher than EPA estimated for both BATW and FGD wastewater. When the procedural and potential technology costs of setting additional BPJ limits for BATW purge are considered, the actual costs of BATW would be even higher. These increased costs necessarily will increase adverse economic impacts.

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[240] See EPRI, *Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges*, EPA-HQ-OW-2009-0819-7346; EPRI 2020 Comments; Id. at Appendix B: FGD Wastewater Treatment Cost Methodology—Biological (2020); Id. at Appendix C: FGD Wastewater Treatment Cost Methodology—Vapor-Compression Evaporation/Crystallization (2020); Id. at Appendix D: FGD Wastewater Treatment Cost Methodology—Brine Solidification (2020); Id. at Appendix G: FGD Wastewater Pollutant Reduction Methodology (2020).

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Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 59

Comment Excerpt:

8.4 **Bottom ash transport water costs to the industry**

EPRI's cost estimate to convert all plants in the industry to a high recycle rate system (less those retiring by December 31, 2028) was $3,103 million capital cost, with a total annualized cost of $433 million per year. EPRI, like EPA, also removed the costs for R. D. Morrow, which retired in 2018. EPRI's cost estimating approach is documented in Appendix F.

EPA's cost estimate for Option 2 underestimates the cost of rMDS, potentially due to not fully accounting for costs outside of the rMDS equipment itself, as was the case with the FGD cost estimates described above. EPRI's capital cost estimates are based on total engineering, procurement, and construction (EPC) costs project examples for 10 plants across five utility companies. Table 8-3 outlines some of the major equipment or components included in each of EPRI's estimates. All the facilities included related pumps and piping, and pile foundations.

Table 8-3
Major components in EPC costs used as a basis for EPRI's rMDS cost curve

EPC Ex.	No. of Units	No. of rMDS	Economizer Ash Included	Polishing Clarifier	Lamella Plates	Maintenance Tank	Building [2]	Chemical Feeds
#1	1	2	Yes	Yes		Yes [1]		Yes [1]
#2	2	2				Yes [1]		Yes [1]
#3	4	3				Yes		Yes [1]
#4	1	2				Yes	Yes	Yes [1]
#5	1	1	Yes		Yes	Yes	Yes	Yes
#6	2	2	Yes		Yes	Yes	Yes	Yes
#7	1	2			Yes	Yes	Yes	Yes
#8	2	2			Yes	Yes	Yes	Yes
#9	2	2			Yes	Yes	Yes	Yes
#10	4	3			Yes	Yes	Yes	Yes

[1] EPRI estimated the cost for these items for this facility to normalize costs since most systems will need a chemical addition system.
[2] Some plants in EPRI's data set elected to place rMDS systems into a building both to protect the system from the elements and minimize stormwater introduction to the system.

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Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 68

Comment Excerpt:

F —APPENDIX: BOTTOM ASH HANDLING COST METHODOLOGY

F.1 Cost estimating summary for conversion of wet to dry bottom ash handling

F.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the cost of conversion of wet to dry bottom ash handling for the steam electric industry based on EPA's industry profile [ERG, 2019a]. This appendix describes the method for calculation of the cost of conversion of wet to dry bottom ash handling for an individual plant, the assumptions associated with the cost calculations, and the estimated costs for the steam electric industry. Table F-1 outlines the cost to the current industry to convert from wet to dry bottom ash handling.

Table F-1
Treatment cost to industry for complying with bottom ash transport wastewater ELG proposed rule, in June 2018 dollars [a,b]

Treatment Option	Capital Cost ($M)	Operations and Maintenance Cost [c] ($M per year)	Annualized Cost [d] ($M per year)
Convert from Wet to Dry Bottom Ash Handling	$3,103	$140	$433

M = million
$ = U.S. dollars
[a] Costs estimated for units at or above 50 MW generating capacity.
[b] Costs represent EPA's 2019 plant list [ERG, 2019b], adjusted to account for retirements of R. D. Morrow (ID 1185) and Units 1 and 2 of Chesterfield Power Station (ID 4679) as of the end of 2018 (a total of 207 generating units in 92 plants). EPRI's list also does not include Lewis & Clark (ID 394) which is at the 50-MW limit.
[c] Operation and maintenance cost based on 2017 net generation capacity factors.
[d] Annualized cost based on 20-year equipment life and 7% interest rate

F.1.2 Treatment equipment overview

EPRI evaluated the following two technology options that EPA evaluated for bottom ash transport water:

- Mechanical drag system (MDS)
- Remote dewatering process – such as remote mechanical drag system (rMDS)

Under the boiler mechanical drag systems are needed for each unit. The number of remote dewatering process treatment trains for each facility was based on the following:

- Sites with 1 to 3 generating units were assumed to have 2 sets of dewatering process equipment.
- Sites with 4 to 5 generating units were assumed to have 3 sets of dewatering process equipment. EPRI evaluated the following two technology options that EPA evaluated for bottom ash transport water:
- Mechanical drag system (MDS)
- Remote dewatering process – such as remote mechanical drag system (rMDS)

Under the boiler mechanical drag systems are needed for each unit. The number of remote dewatering process treatment trains for each facility was based on the following:

- Sites with 1 to 3 generating units were assumed to have 2 sets of dewatering process equipment.
- Sites with 4 to 5 generating units were assumed to have 3 sets of dewatering process equipment.
- Sites with 6 to 7 generating units were assumed to have 4 sets of dewatering process equipment.
- Sites with 8 to 9 generating units were assumed to have 5 sets of dewatering process equipment.
- Additional consideration was given on a case-to-case basis if multiple units were above 250 MW. For example, if a plant had 7 generating units and 6 were larger than 250 MW

then we would assume 5 treatment trains to account for supporting the larger units' ash production.

F.1.2.1 Mechanical drag system

The Mechanical Drag System for which costs were developed consists of chain-mounted flight bars submerged in a water trough below the boiler in place of the existing bottom ash hoppers. The ash drops directly into the water trough and settles down into the water and onto the MDS. The ash is evacuated mechanically on a continuous basis so there is no long-term storage in the water trough beneath the boiler.

Water in the MDS is pumped continuously into the trough for makeup and cooling water. From there, the bottom ash is conveyed up a dewatering slope at an angle suitable for dewatering the ash down to approximately 20% moisture content. The bottom ash then enters into a transfer chute and then into a clinker grinder/crusher to rid the ash of any large bound material. The clinker grinder then deposits the bottom ash into a collection pit. A front-end loader can then be utilized to remove and load the dewatered ash into a transportation truck for onsite or offsite landfill storage.

F.1.2.2 Remote mechanical drag system

The remote MDS is much like the under-the-boiler MDS, except for the fact that the remote MDS equipment is located outside the plant and away from the bottom of the boiler. The bottom ash falls into the bottom ash hoppers and moves through the clinker grinders. Existing or new bottom ash sluice pumps and bottom ash sluice piping remove the bottom ash from the existing bottom ash hoppers under the boiler. The ash is then conveyed via the ash sluice piping to the remote location of the MDS. The piping deposits the bottom ash into the trough area and it settles down through the water onto the submerged flight chain conveyor. From here the bottom ash is slowly conveyed up a dewatering slope at an angle suitable for dewatering the ash down to approximately 20% moisture content. The bottom ash then enters into a transfer chute and is deposited down into a storage area in a building enclosure or an outdoor concrete storage area. A front-end loader can then be utilized to remove and load the dewatered ash into a transportation truck for onsite or offsite landfill storage.

The transport water overflows to weirs or additional settling devices, such as lamella plates, and then is re-circulated back to the bottom ash hoppers via recirculation pumps. Any water from the dewatered ash pile is collected and returned to the dewatering conveyor. Makeup water is also tied into the system to replace water lost to evaporation and entrained in the removed ash. This makeup water can be water taken from other plant systems that would normally discharge into the existing ash ponds. The remote MDS removes bottom ash intermittently.

F.1.3 Overview of cost methodology

Capital and operating costs were developed for both the under-the-boiler MDS and remote MDS technologies. EPRI used EPA's industry profile [ERG, 2019a] and technology treatment selection from the EPA's bottom ash calculation database [EPA, 2019] to determine which units would be priced for either under-the-boiler MDS or remote MDS treatment systems. No costs were assigned to units that EPA noted as not needing either treatment system, presumably because existing systems were already in place. Of the 207 units in EPRI's estimate (after the exclusions noted in the footnotes for Table F-1), 5 units were priced for under-the-boiler MDS systems, 91 units were priced for remote MDS systems, and 111 units were assigned no costs. Capital and operating costs were adjusted for mid-2018 dollars.

F.1.3.1 Remote MDS cost overview

F.1.3.1.1 Remote MDS capital cost development per plant

EPRI spoke with United Conveyor Corporation (UCC) and EPRI members to develop capital and operating cost estimates. The capital costs developed were based on total engineering, procurement, and construction (EPC) costs project examples for ten plants, with a range of unit capacities (megawatt (MW)) and number of power units, across five utility companies. One of the plants employed one remote MDS unit, seven of the plants employed two remote MDS units, and two of the plants employed three remote MDS units. All of the facilities included related pumps and piping, and pile foundations. Eight of the facilities included maintenance tanks to hold water drained from the system during maintenance; EPRI estimated the cost of including maintenance tanks for the other two facilities. Six of the facilities included chemical feed systems; EPRI estimated the cost of including chemical addition for the other four plants. One of the plants included thickeners for removing fine solids from the wastewater that are entrained in the remote MDS overflow, while six of the plants employed lamella plates in the MDS for fines removal. Four of the facilities included a building to house the equipment, while the other six did not. These different types of facilities represent the spectrum of equipment that a facility would install if installing remote MDS because not all facilities will install equipment for fines management (thickeners, lamella plates), not all facilities will include a building to house the equipment, and facilities will choose to include different levels of redundancy.

EPRI normalized the costs for each plant based on a dollar-per-remote MDS unit basis and calculated an average unit cost for each utility company. EPRI then used the average unit cost from the five companies to calculate capital costs. In addition, EPRI added a plant engineering factor of 0.035 for the plant's own engineering to the vendor EPC cost to estimate a total capital cost. To calculate a plant's remote MDS capital cost, the total number of remote MDS units required per plant was estimated based on the number of power units greater than 50 MW and input from UCC, and the dollar per remote MDS unit was used to calculate capital costs per plant.

There were 214 plants with a total of 645 units identified for the industry extrapolation in EPRI's 2013 ELG comments. Units from this list that have retired or converted to natural gas as of the end of 2018 (289 units) have been excluded from EPRI's current estimates. For the remaining units, it was assumed that each was equipped with the same technology as was reported in the 2013 ELG Information Collection Request (ICR).

F.1.3.1.2 Remote MDS operations and maintenance cost development per plant

Annual labor, energy, chemicals, maintenance, and disposal costs were calculated per plant to determine a facility's operations and maintenance (O&M) cost. The major assumptions used in calculating these estimated O&M costs were:

- Costs are presented in June 2018 dollars. Construction Cost Index values, as published by Engineering News Record (ENR), were used to de-escalate costs from more recent information to June 2018 pricing.
- Labor: a total of one incremental full-time equivalent (FTE) operator at $49/hour was assumed to staff the remote MDS in addition to the staff currently employed at the facility in charge of wet sluicing operations. Since remote MDS operations are intermittent, it is assumed that the system would operate a total of 6 hours per day at each facility.
- Chemicals: A number of facilities must add either sulfuric acid and antiscalant to control scaling in the recirculated water supply, or, if experiencing acidification, a combination of caustic and soda ash for pH adjustment and corrosion prevention. These latter facilities may also find the need to occasionally add antiscalant depending on the hardness present in the service water. The facilities experiencing acidification and requiring caustic and soda ash appear to have larger chemical demands than those requiring sulfuric acid. To be conservative, it was assumed that all the facilities may require a combination of caustic, soda ash, and antiscalant. A dosage of 90 gallons per day of 50 percent caustic was assumed with a unit cost of $3.41 per gallon. A dosage of 100 pounds per day of soda ash was assumed with a unit cost of $0.16 per pound. A dosage of 10 parts-per-million (ppm) antiscalant was assumed with a unit cost of $17.10 per gallon. Dosages were based on EPRI experience with facilities requiring these chemicals.
- Disposal: All solids will be Resource Conservation and Recovery Act (RCRA) nonhazardous solids with a disposal unit cost of $54 per dry ton. The disposal cost was developed as a weighted average using onsite and offsite disposal costs provided in *Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* [EPA, 2013] and updated for 2018 pricing. EPRI assumed 75% of plants would use onsite disposal facilities at $40.41 (2010 pricing) per dry ton, and 25% of plants would use offsite disposal facilities at $49.82 (2010 pricing) per dry ton.
- Energy: Electrical costs were estimated using the value used by EPA, $0.0523/kilowatt-hour (kWh), corrected for 2018 dollars, which is the unit cost provided in Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category [EPA, 2013].
- Energy: The following electrical equipment were used to calculate the total horsepower (hp) requirement to calculate electrical costs:
  - Hydraulic power unit to operate drag chain –75 hp
  - Chemical feed pump – 0.5 hp
  - Low-pressure recirculation pump – 200 hp
  - High-pressure recirculation pump – 200 hp
  - Sump pump with motor –20 hp
  - Overflow return pump with motor – 50 hp

- Maintenance: Annual equipment maintenance costs will be 5.0 percent of the total equipment costs for the facility. The total equipment costs for the facility were assumed to account for 25 percent of the total EPC cost per input from UCC.

F.1.4 MDS cost overview

F.1.4.1 MDS capital cost development per plant

EPRI developed the cost curve shown in Figure F-1 for EPC cost for the under-the-boiler MDS technology based on input from UCC.

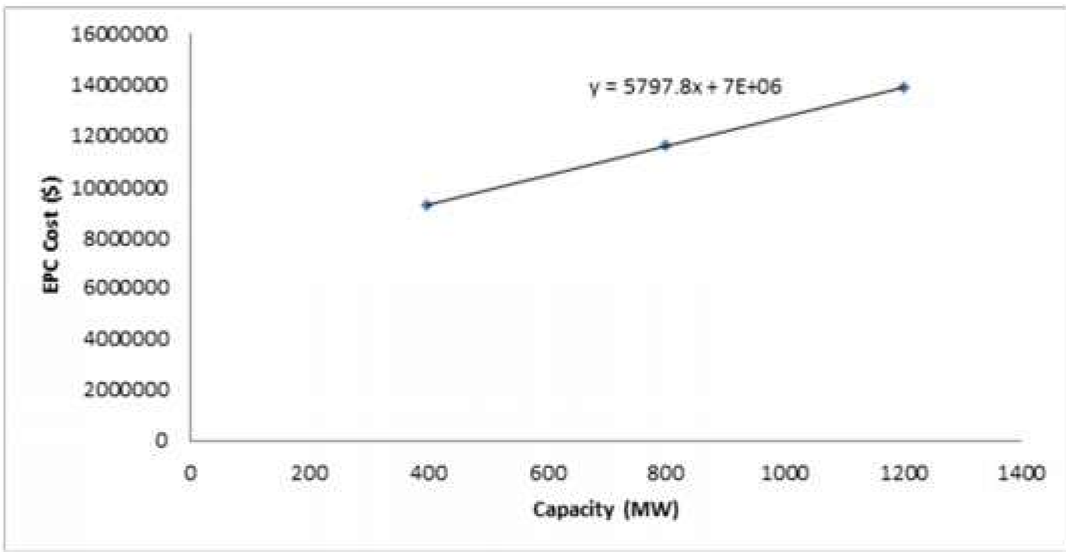

Figure F-1
Capital cost curve for under-the-boiler MDS in June 2018 dollars

In addition, EPRI added a plant engineering factor of 0.035 for the plant's own engineering to the vendor EPC cost to estimate a total capital cost. Capital costs were calculated for each under the-boiler MDS unit and summed for facility total.

F.1.4.2 MDS operations and maintenance cost development per plant

Annual labor, energy, chemicals, maintenance and disposal costs were calculated per plant to determine a facility's O&M cost. The major assumptions used in calculating these estimated O&M costs for the MDS were:

- Costs are presented in June 2018 dollars. Construction Cost Index values, as published by Engineering News Record (ENR), were used to de-escalate costs to June 2018 pricing.
- Labor: it was assumed that no incremental labor would be needed over that used for existing wet sluicing operations.
- Energy: Since MDS operations are continuous, it is assumed that the system would operate a total of 24 hours per day at each facility.

- Chemicals: No chemicals were assumed for the MDS.
- Disposal: All solids will be Resource Conservation and Recovery Act (RCRA) nonhazardous solids with a disposal unit cost of $54 per dry ton. The disposal cost was developed as a weighted average using onsite and offsite disposal costs provided in *Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* [EPA, 2013]. EPRI assumed 75% of plants would use onsite disposal facilities at $40.41 per dry ton (2010 pricing), and 25% of plants would use offsite disposal facilities at $49.82 per dry ton (2010 pricing).
- Energy: Electrical costs were estimated using the value used by EPA, $0.0523/kilowatt-hour (kWh), corrected for 2018 dollars, which is the unit cost provided in *Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* [EPA, 2013].
- Energy: The following electrical equipment were used to calculate the total horsepower (hp) requirement to calculate electrical costs:
  - Hydraulic power unit used to operate drag chain- Unit Capacity <=500 MW = 50 hp
  - Hydraulic power unit used to operate drag chain- Unit Capacity >500 MW = 75 hp
- Maintenance: Annual equipment maintenance costs will be 5.0 percent of the total equipment costs for the facility. The total equipment costs for the facility were assumed to account for 30 percent of the total EPC cost per input from UCC.
- Wet sluicing credit: A wet sluicing credit for maintenance and energy costs was applied to each facility to subtract the cost of wet sluicing operations from each O&M estimate. The wet sluicing credit was developed based on EPA's cost assumptions for maintenance and energy costs cited in *Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* [EPA, 2013].

F.1.5 Recurring costs

EPRI used the same assumptions as EPA for recurring costs for drag chain replacement. The drag chain replacement would cost $220,000 and would occur every 3 years for the under-the-boiler MDS and every 5 years for the remote MDS.

F.1.6 Annualized costs

EPRI assumed a 20-year life and 7 percent interest rate to develop annualized capital costs for each facility's system. Annualized costs for each facility were developed by taking the annualized capital cost, annual operating cost, and annualized recurring cost to calculate a total annualized cost for each facility.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)

Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 42

Comment Excerpt:

X. EPA's Cost Calculations for the Proposed High Recycle Rate BATW System Do Not Include All of the Costs That the Proposal Appears to Anticipate.

As previously noted, the components of the model high recycle rate bottom ash system that EPA proposes to identify as BAT are an RMDS, a sump, recycle pumps, a chemical feed system, and a semi-dry silo. Supplemental TDD at 5-33. These are the only components for which EPA provided cost estimates. EPA did not estimate the costs of installing "spare" or "redundant" systems, additional containment, maintenance tanks, or other, unspecified "secondary bottom ash system equipment." Nor did it identify or include any costs for other system components that might be used or practices that might be followed at specific sites. For purposes of estimating the size, and thus the cost, of the RMDS system, sumps, and recycle pumps, it is not clear what EPA assumed about the amount of storm water, if any, the model system would need to be sized to accommodate.

As discussed earlier, EPA's Proposed Rule allows the discharge of BATW purge only under specified circumstances, several of which would require that the volume of water cannot otherwise be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash equipment. Proposed §§ 423.13(k)(2)(i)(A)(1), (3). It further requires that the level discharged be reduced or eliminated to the extent achievable using control measures (including BMPs) that are technologically available and economically achievable in light of BMPs. Proposed § 423.13(k)(2)(i)(B). These provisions could be read to require far more technology than EPA's cost analysis has accounted for.

EPA's record shows that the model technology EPA considered did not include spares, redundancies, and the like. EPA should determine that technology is BAT, if operated properly to maximize recycling of BATW within the site-specific capability using the model system for either RMDS or dewatering bins. The rule should reflect that determination. The Proposed Rule's language, which suggests that more technology may be needed as a condition of any BATW purge discharge, if the permit writer determines the additional technology is "technologically available" and "economically achievable," neither provides the necessary certainty nor identifies a meaningful standard. EPA has all of the information it needs to conclude that the model technology, which will provide a high level of recycling if properly operated in accordance with the BMPs outlined in Section III above, is the most that is economically achievable.

That said, if EPA intends to require additional technology components, it should identify them and calculate their costs. EPRI's cost analysis, which is based on the average costs for 10 plans, 7 of which have more than the model technology for which EPA developed costs,[53] is 70 percent higher than EPA's cost estimate for plants with the same flow rates. Moreover, none of the plants on whose real-world experience EPRI based its BATW cost estimate had all of the technology components potentially required by EPA's proposal.

[53] EPRI 2020 Comments, Table 8-3 at 8-5.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 20

Comment Excerpt:

The cost estimates that EPA uses for necessary upgrades for bottom ash transport water at TVA's four remaining active sites (i.e., Cumberland, Gallatin, Kingston, and Shawnee) are not correct. EPA's cost estimates are markedly lower than TVA's for only doing the recirculating portion of the BATW projects to just "close the loop" and do not include additional treatment which may be needed to meet a BPJ determination on discharge limitations. In the ERG memo the total costs to be incurred by TVA for Cumberland, Gallatin, Kingston, and Shawnee combined was approximately $27M. TVA estimates that the total cost for these plants combined will be approximately $108M just to "close the loop." The potential additional costs for having to install additional BPJ BAT wastewater treatment of the 10% blowdown are not included in these cost estimates further increasing the difference between EPA's and TVA's cost estimates.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 40

Comment Excerpt:

A. The Environmental Impact of a 10 percent by Volume Discharge Allowance is Minimal.

A 10 percent by volume discharge allowance—compared to the overall removals of BATW-related pollutants—is a small adjustment, based on EPA's calculations of TWPEs. EPA calculated the TWPEs present in BATW discharges as of October 2018 and estimated the TWPEs for BATW under the Proposed Rule. EPA's calculations indicate that the Proposed Rule would result in a 75.8 percent reduction in BATW TWPEs from current practices as shown in the table below.

	Current Industry Practice (Oct. 2018)	Proposed Rule	Percentage Reduction
BATW TWPEs	93,800[38]	22,700[39]	75.8%

As to overall pounds of pollutant loadings attributable to BATW, the reductions are of a similar magnitude to EPA's predicted TWPE reductions. Using EPA's calculations of loadings in pounds per year, the percentage reduction from 2018 industry practices to the Proposed Rule is approximately 75.7 percent.[40]

EPRI calculated BATW loadings assuming current industry practices and Option 2 BATW loadings and TWPEs as follows: Flow in Gallons Per Day (either Ash Sluice flow or 10 percent Purge EPA Estimated Flow) x Online Capacity Factor x 365 Days Per Year x Pollutant Factor, where for the Pollutant Factor constant for either single pass or recirculated water are used. These are:

- Single-Pass BATW: 1.51E-06 TWPE Per Gallon and 6.07E-04 LBs Pollutants Per Gallon as calculated by EPRI.
- Recirculated BATW (for purges in Option 2): 3.06E-06 TWPE Per Gallon and 1.84E03 LBs Pollutants Per Gallon as calculated by EPRI.

Regulatory Option	Loadings (lbs)	TWPEs
Current Industry Practice	29,000,000	72,000
Option 2	3,540,000	7,800

EPRI finds that Option 2 decreases TWPE due to BATW by about 89 percent over the Current Industry Practice case. EPRI 2020 Comments, Appendix H at H-5. Similarly, loadings decrease by about 88 percent.

Again using EPA's calculations, the percentage reduction under the Proposed Rule, as compared to industry BATW discharges prior to the 2015 rule, climbs to 93.4 percent.

	Pre-2015 Rule	Proposed Rule	Percentage Reduction
BATW TWPEs	344,014[41]	22,700[42]	93.4%

Overall, then, according to EPA, the Proposed Rule would remove approximately 93.4 percent of the TWPEs attributable to BATW, while allowing a minimal purge discharge.

The Proposed Rule's impact on BATW TWPEs can also be evaluated on an average unit basis. EPA calculated BATW TWPEs for all units that would discharge the 10 percent by volume purge allowed under the Proposed Rule (Option 2). *See* ERG, *Memorandum re: Generating Unit-Level Costs and Loadings Estimates by Regulatory Option - DCN SE07090,* EPA-HQ-OW-2009-0819-8220 ("ERG, Unit Costs & Loadings") (Sept. 25, 2019), Table 20 at 127-30. Based on EPA's analysis for all units expected to make use of the discharge allowance, the units' estimated discharge of BATW purge ranges from 10-60 TWPEs per year. Id. In contrast, the pre-2015 rule discharges of BATW per unit averaged 4,183[43] TWPEs per year. Under the Proposed Rule, the units assigned a BATW purge by EPA average 28 TWPEs per year, or less than 0.7 percent of the pre-2015 rule average.

In fact, the estimated BATW purge TWPEs are so low it is likely that TWPEs present in the source waterbodies of the plants—prior to any industrial use—are higher. In 2013, UWAG collected BATW characterization data[44] and estimated TWPEs for various megawatt ranges, both with and without accounting for estimated source waterbody contributions. The results indicated that source water contributions average 34-37 percent of the total BATW TWPEs.[45]

[38] ERG, *Memorandum re: Pollutant Loadings Analysis and Supporting Documentation for the 2019 Steam Electric Supplemental Environmental Assessment,* EPA-HQ-OW-2009-0819-7733 (Sept. 13, 2019) ("ERG, EPA-HQ-OW-2009-0819-7733"), Table 4 at 7.
[39] Id.
[40] Id., Table 3 at 7 (374,000,000 lbs/yr reduced to 91,000,000 lbs/yr).
[41] See 2015 TDD at 10-43 (showing 344,014 BATW TWPEs removed by Option D, which was the selected "zero discharge" option). Since this option was near "zero discharge," these TWPEs approximate the entire BATW TWPEs attributable to BATW, excluding TWPEs attributable to the less than 50 MW units.
[42] ERG, EPA-HQ-OW-2009-0819-7733, Table 4 at 7.
[43] In the 2015 rule, EPA identified 115 plants discharging BATW (excluding those with combined ash pond discharges) and estimated 481,000 TWPEs per year attributable to BATW. 2015 TDD, Table 10-14 at 10-35. Therefore, the per-unit average was 4,183.
[44] UWAG Comments on Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-HQ-OW-2009-0819-4655, Attachments 7-9 (Sept. 20, 2013).
[45] On a pound per unit gallon basis, EPRI finds pollutants present in source water make up about *79 percent* of BATW. EPRI 2020 Comments at 6-3.

22 <u>BATW – BMP Plan</u>

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 60

Comment Excerpt:

EPA also underestimates other costs. EPA's cost for plants that require best management practices (BMP) plans appears inconsistently applied [ERG, 2019a]. The Technical Development Document (TDD) describes a cost of consulting necessary to develop a BMP, and some plants do have a cost listed in Table 10 of the ERG document [ERG, 2019b]. But most plants in the Bottom Ash BMP section have zero costs. Examples include TVA Kingston (ID 265), Chesterfield (ID 4679), and TVA Shawnee (ID 6602). Accounting for BMP costs at all applicable plants would add hundreds of thousands of dollars to the total cost.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 19

Comment Excerpt:

However, the requirement to develop a best management practices (BMP) plan that aims to **minimize the discharge of pollutants by maximizing recycle** for a low utilization boiler as currently written in Part 423.13(k)(3)(iv)(E) may not be substantially different from the requirements for facilities that do not qualify for the subcategory. TVA believes that **minimization of discharge of pollutants to the extent practicable** is a more appropriate BMP standard for low utilization boilers because costs are noted to be a factor in determining BMP. As EPA noted on Page 64664: "The proposed BMP provisions would require applicable facilities to develop a plan to minimize the discharge of pollutants by recycling as much BA transport water as practicable back to the BA handling system. For example, if a facility could recycle 80 percent of its BAT transport water for a few thousand dollars but recycling 81 percent would require the installation of a multi-million dollar system, the former would be practicable, but the latter would not." Although there are positive aspects to maximizing recirculation of BATW including the reduction in water withdrawals, there are scenarios involving low utilization boilers in which maximizing the recirculation rate is not the most cost-effective or practicable approach. For example, TVA's Kingston facility will face a significant cost (approximately $10M) to upgrade the nine boiler bottoms in order to complete the project to recirculate BATW; the cost is to upgrade the boiler bottoms will add approximately 20% to the costs of installing recirculation equipment. (See comment below about the differences in EPA's and TVA's projected costs.) Where cost is properly evaluated in establishing a BMP to maximize recycle, this project would not be practicable and therefore should not be required at Kingston. Instead, TVA believes the goal of minimization of pollutants to the extent practicable is the appropriate goal. Consequently, TVA believes that the planned chemical addition/clarification for the discharges at Kingston, rather than maximizing recycle, is the more appropriate BMP strategy.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 25

Comment Excerpt:

423.19(d)(1) should be modified to read that "the certification statement shall be made with the permit application **or within two years, whichever is later**". This would address the case in which the permittee already has an issued or pending permit.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 26

Comment Excerpt:

TVA requests that EPA reconsider the logic and/or wording for the submittal of the initial certification in 423.19(d)(3)(D). It appears that the permittee is required to submit an **approved** BMP plan, but there is no requirement to submit that plan prior to the initial certification so it is not apparent by whom the BMP plan would be approved.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 27

Comment Excerpt:

Similarly there is a requirement in 423.19(d)(4)(D) to submit a copy of the annual inspection report; however, there is not a prior mention of an annual inspection requirement.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 108

Comment Excerpt:

D. If EPA Requires a BMP Plan for BATW, It Should Amend and Clarify its Proposed Approach.[223]

1. EPA's Proposed Approach is Not Workable Because It Is Akin to a BPJ Determination.

The Agency proposes to require permittees with units in the Low Utilization Subcategory that discharge BATW to "prepare, implement, review, and update a BMP plan for the recycle of" BATW. Proposed § 423.13(k)(3). The BMP plan would need to include an "evaluation of options and feasibility, accounting for the associated costs" to minimize discharges of BATW, including recycling BATW back to its own system or a FGD scrubber and "installing new equipment where practicable to achieve the maximum amount of recycle." Proposed § 423.13(k)(3)(v).

While UWAG supports BMP approach to regulating BATW generated by units within the Low Utilization Subcategory, EPA's proposed BMP plan is unworkable. As proposed, the BMP plan amounts to a "BPJ" determination for BATW discharges from low utilization units, even though EPA's explicit intent is *to avoid case-by-case BPJ* for this subcategory. See 84 Fed. Reg. at 64,639 (finding a BPJ approach for this subcategory "problematic" because implementation of high recycle rate technologies would "result in unacceptable disproportionate costs.") EPA's proposed plan is very similar to a BPJ approach because it requires the "[e]valuation of options and feasibility, accounting for the associated costs, for eliminating or minimizing discharges of bottom ash transport water….." Proposed § 423.13(k)(3)(v). This evaluation mandates consideration of virtually *all technologies* that might be employed to reduce discharges of BATW, including:

- segregating BATW from other process water (which is often a very costly step, involving excavation of pipes and sumps and rerouting of wastewaters, and also would require evaluation of how the rerouting would affect wastewater treatment within other plant systems);
- minimizing storm water introduction to the system through covering and curbs;
- recycling BATW to the FGD scrubber, which would require not only new pipes and pumps but also evaluation of the effect of introduction of BATW on the scrubber chemistry and operations, as well as the marketability of gypsum marketing where applicable;
- "optimizing existing equipment (e.g., pumps, pipes, tanks) and installing new equipment where practicable to achieve the maximum amount of recycle;"[224] and
- "utilizing 'in-line' treatment of transport water (e.g., pH control, fines removal) where needed to facilitate recycle."[225]

As proposed, EPA's BMP approach reads more like a wholesale, site-specific technology evaluation that is very similar to a BPJ determination because it not only requires comprehensive technology reviews, but also cost information for each possible technology option. And the review is not limited to those technologies that would minimize BATW, but also includes technologies (within the options laid out in § 423.13(k)(3)(v)) designed to eliminate BATW. Requiring a BMP plan that is a virtual BPJ determination is not appropriate for low utilization units, which are by definition marginal units.[226]

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[223] In the event EPA decides to impose a BATW BMP plan on low utilization units, UWAG believes, at a minimum, EPA should not include new requirements for those circumstances described in Section XX.B.
[224] Proposed § 423.13(k)(3)(v)(E).
[225] Proposed § 423.13(k)(3)(v)(F).
[226] Also, implementing EPA's proposed BMP plan would be difficult for the permittee and for the permitting authority. As with BPJ determinations, the permitting authority would be faced with the daunting task of determining whether the permittee's BMP plan accurately evaluated a raft of technology options and their costs.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 109

Comment Excerpt:

2. A Workable BMP Plan is Appropriate for Regulating BATW Discharges from Low Utilization Units.

As discussed in Section III.G., applying BMPs to industry categories through inclusion in ELG regulations is a well-established approach. See 40 C.F.R. §§ 122.44(k)(1),(3) (specifying BMPs may be applied for several reasons, including when "numeric effluent limitations are infeasible").

In this case, numeric effluent limitations for BATW are infeasible for low utilization units. The designs of existing BATW treatment systems are quite varied, ranging from RMDS systems to dewatering bin systems to treatment basin systems. Setting a single set of numeric effluent limitations beyond BPT TSS limits across these existing systems would be extremely difficult and very data-intensive. Even assuming that EPA decided to set a single numeric effluent limitation for each type of BATW system, it would be nearly impossible to do so because the systems operate differently according to site-specific conditions. Given variations among the existing systems owned and operated by potential low utilization units—and given that EPA's objective in developing this Subcategory is to avoid mandating technologies that will drive these units to close—a workable BMP approach for BATW makes good sense and ensures a further level of protection above BPT controls.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 110

Comment Excerpt:

3. UWAG Recommends EPA Consider Automatic Process Controls and an Amended BMP Plan.

UWAG recommends EPA consider a dual approach to establishing BATW BAT for the Low Utilization Subcategory. First, permittees could install automatic process controls ("APCs") that would allow them to automatically control BATW treatment systems. Example of APC technology include programmable logic controllers ("PLCs") or distributed control systems. Additionally, the proposed BMP procedures should be replaced with a BMP plan under which the permittee would evaluate how to maximize recycling of BATW ***consistent with the use of its existing BATW technology*** and, if warranted, APCs.

By installing an APC system for BATW, operators of low utilization units can automatically control BATW discharges. Once operators have analyzed the maximum recycle rate through their BMP evaluation, they can set the automatic controls to ensure that all BATW discharges are consistent with maintaining that maximum rate. In the case of maintenance work or other special circumstances, facility operators will be able to override the APC and manually control any discharges. The use of APCs to monitor operations will minimize the chances of operator error leading to discharges that do not reflect the maximum recycle rate.

By basing the BMP assessment on a unit's ***existing BATW recycle technologies*** (and APC technology if warranted), EPA will ensure that the BATW maximum recycling requirement does not result in costs beyond those associated with installing a BATW APC technology, like a PLC, which is estimated to cost hundreds of thousands of dollars per unit. For instance, the operator would not be required to consider recycling BATW as makeup water in the FGD scrubber unless the piping and pumps necessary to do so were already a part of the system's equipment and when recycling would not interfere with FGD operations or gypsum beneficial reuse. The operator would, however, be required to minimize its sluice flow rate to the extent practicable in light of the system's existing components (i.e., if existing pumps, drives, and piping can be modified or used to address a change in BATW flows). In short, all adjustments that would maximize recycling could be made through a site-specific BMP plan.

In line with UWAG's recommendation, EPA should revise its proposed BMP plan by removing all of the Proposed § 423.13(k)(3)(v) requirements, which mandate evaluation of other technology options and their feasibility, including associated costs. As discussed above, Proposed § 423.13(k)(3)(v) amounts to a BPJ determination and is not appropriate for this Subcategory.

Also, Proposed §§ 423.13(k)(3)(vi), (vii)(A), and (vii)(B) should be amended to remove language related to construction or installation of new technologies.

Finally, Proposed § 423.13(k)(3)(ix) would require dischargers to perform weekly flow monitoring for make-up water to the BATW system, sluice flow rate, discharge to surface water or a POTW, and recycle flow back to the bottom ash system or FGD scrubber. This level of monitoring is very burdensome and it is not clear that EPA has accounted for the additional costs of weekly monitoring. Instead, EPA should simply require the facility to operate its BATW system in accordance with its approved BMP plan.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 15

Comment Excerpt:

1.5 Best Management Practices

EPA has proposed that only a subcategory of plants, those falling into EPA's proposed low utilization subcategory, develop a BMP plan for handling BATW. The proposal leaves it to the plants to develop such plans with no details.

While BMPs are a good idea in concept, they rarely work unless they have quantitative requirements to the maximum extent possible and are therefore enforceable. Often BMPs simply consist of a set of qualitative statements, expressing general or conceptual goals and objectives.

However, they are not a substitute for enforceable standards. Since EPA has not shown that low-utilization plants (a new proposed subcategory) cannot also achieve zero discharge, reliance upon BMPs alone for such plants is unjustified.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 17

Comment Excerpt:

Second, if EPA opts not to impose zero discharge standards for BATW on any facility, EPA must strengthen its BMP requirement by including specific suggestions for the contents of a "model" BMP in its proposal. While plants can and should create tailored BMPs addressing their specific circumstances, general approaches can be suggested by EPA. In fact, EPRI (2018) contains a reasonable (though not exhaustive) starting point for such ideas. I have relied on and re-cast the "potential mitigation solutions" from EPRI (2018, Table 1-1) below with specific suggestions for elimination or reduction of various sources of purge water.

For Purges Driven By Water Imbalances

- Stormwater introduction above storage capacity of recirculated water supply
    - Yard improvements to redirect stormwater, which may include: regrading, repaving, curb additions, or addition of new sumps, pumps, and treatment processes.
    - Cover equipment or enclosure in building, including ash bunkers or ash dewatering pads.
    - Add storage capacity relative to volume and risk of concurrence with other events.
- Utilizing bottom ash dewatering equipment to treat other wastestreams (e.g., landfill leachate, NCMCWs)
    - Design new treatment facilities for other wastewaters, so they will not enter the closed-loop.
    - Modify system and cleaning practices to redirect water during cleanings unless contact with transport water is unavoidable, in which case configure system to use recirculated water for wash (i.e., supply local area hoses dedicated only for this purpose).
    - Add storage capacity relative to volume and risk of concurrence with other events.
- Boiler tube leaks adding water to bottom ash hoppers
    - Add storage capacity relative to volume and risk of concurrence with other events.
- Use of service water (rather than bottom ash recirculated water) as cooling water for ash hopper(s) due to recirculated water supply being too hot

  - Add heat exchangers and controls to cool recirculated water when needed
- Introduction of new water to the closed-loop due to cross-connections
  - Replace and correct as discovered (typically during start-up and commissioning).
  - Design system such that all cross-connections are eliminated (i.e., only have service water added to dewatering system for water makeup).
- Water introduction to bottom ash hopper area sump(s), such as area washdowns
  - Redirect non-transport water to new sumps or modify existing sumps (if possible) to segregate ash transport water from non-transport water. This could require relocating equipment that drains to the sumps or modifying the trenches, piping, and sump pumps of other sumps that direct water to the hopper area sump.
  - Modify operation practices to minimize introduction of water.
  - Add storage capacity relative to volume and risk of concurrence with other events.

For Purges Driven By Leaks

- Sluice line rupture
  - To some extent unavoidable unless utilizing double-lined piping with leak monitoring or plant is able to otherwise contain and remove water from a rupture throughout the pipe length (such as a dedicated trench). However, water loss can be minimized utilizing other controls, specifically:
  - Have two sluice lines, such that sluices can be directed to the second line when a failure occurs on the initial line. However, this does not prevent a discharge if lines are near a receiving stream or storm drain and the flow is not stopped prior to reaching the receiving stream.
- Failure of sluice door or grinder/crusher during operation which leads to a spill of transport water to floor sumps
  - Tie-in hopper area sumps' discharge into closed-loop system. May include extra controls and piping, especially if multiple piping pathways are needed in case of failure of downstream equipment (such as interim pumps). May also include installing a new sump and/or segregating non-transport waters to prevent excess
- Leaks around hopper system flanges, joints, observation windows, etc.
  - Replace and correct as discovered and as allowed by generation requirements (i.e., correct during outages).
  - Where feasible, tie-in drainage points (i.e., sumps) into the closed-loop system.

For Purges Driven By Maintenance

- Draining hopper contents during scheduled maintenance, including refractory or steel hopper replacement
  - Tie-in hopper area sumps' discharge into closed-loop system. May include extra controls and piping, especially if multiple piping pathways are needed in case of failure of downstream equipment (such as interim pumps). May also include installing a new sump and/or segregating not-transport waters to prevent excess water introduction.
- Drain dewatering system component(s) to inspect interior

    - Have a dedicated maintenance tank to hold contents of part, or all, of the closed-loop system.
    - Configure system such that spare equipment, such as a spare mechanical dewatering vessel, can be used to store water when another is taken offline.
- Drain RMDS to replace/repair components (such as the chain)
    - Have a dedicated maintenance tank to hold contents of part, or all, of the closed-loop system.
    - Configure system such that spare equipment, such as a spare mechanical dewatering vessel, can be used to store water when other equipment is taken offline.
- Failure of multiple conveyance pumps in hopper area resulting in flooding of water from area sump(s) that are incorporated in the closed-loop to other sumps/areas where the water could be discharged
    - Add extra controls and piping to allow for multiple transfer pathways needed in case of failure of downstream equipment (such as interim pumps).

For Purges Driven By Water Quality Considerations

- Purge to avoid corrosive conditions due to low pH water in bottom ash hopper overflow
    - Add pH monitoring and control system (e.g., caustic injection). This may include controls and chemical addition systems at multiple locations in the closed-loop system, as acidic wastewater is sometimes associated with multiple units. Additionally, unless the system has a location with adequate mixing, multiple injections points may be necessary for precise pH control.
    - Add conductivity and/or corrosion monitoring. Corrosive conditions may still be observed because of salt addition from a caustic feed system.
    - Where feasible, include a purge to an FGD system. Where not feasible, the plant will need a salt-removal technology (RO, evaporation, crystallization, etc.).
- Purge to avoid corrosive conditions from cycling up of makeup water supply's salts
    - Add conductivity and/or corrosion monitoring to set purge requirements to maintain non-corrosive conditions.
    - Where feasible, include a purge to an FGD system. Where not feasible, the plant will need a salt removal technology (RO, evaporation, crystallization, etc.).
- Purge to avoid scaling conditions
    - Add pH monitoring/control and scaling control system (e.g., acid injection and anti-scalant) to maintain water quality below scaling conditions. Unless the system has a location with adequate mixing, multiple injections points may be necessary for precise pH control.
    - Where feasible, include a purge to an FGD system. Where not feasible, the plant will need a softening or salt-removal technology (RO, evaporation, crystallization, etc.) to remove solids.
- Purge to avoid corrosive conditions due to salt build-up from chemical addition to control pH and/or scaling
    - Add conductivity and/or corrosion monitoring to set purge requirements to maintain non-corrosive conditions.

  - Where feasible, include a purge to an FGD system. Where not feasible, the plant will need a salt removal technology (RO, evaporation, crystallization, etc.).
- Purge to remove fine solids from recirculated water supply not settled/removed by dewatering equipment
  - Add turbidity monitoring to set purge requirements to maintain acceptable fine solids concentrations during non-sluicing conditions.
  - Add additional settling equipment (lamella plates, thickeners) and flocculants (polymers) for better solids removal. Effectiveness will be based on the characteristics (i.e., size, density) of the residual particulates.
  - Do not remove solids and perform increased maintenance to the closed-loop system because of solids accumulation in tanks and sumps, as well as plugging nozzles or small lines.
  - Include a purge to an FGD system and/or add filtration system to remove fines. The solids may need to be removed prior to the FGD because of the solids can have negative impacts on gypsum marketability or formation. [44]

44 See EPRI (2018) at 1-4 – 1-6 (footnotes omitted throughout).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 36

Comment Excerpt:

2. Requiring Stringent BMP Plans for BA Transport Water Is Problematic

For the subcategory of low utilization boilers, EPA is proposing surface impoundments along with a requirement to prepare and implement a BMP plan under section 304(e)[44] for BA transport water. EPA's rationale is that requiring other technologies would impose a disproportionate cost on low utilization boilers.

The EPA is required to consider, among other things, the cost of achieving effluent reductions when promulgating effluent limitation guidelines.[45] In this Proposed Rule, EPA states that it has considered the costs to low utilization boilers in setting this proposed standard. However, the requirement of preparing and implementing a BMP plan under section 304(e) will impose additional costs that low utilization facilities cannot afford. EPA is proposing that low utilization facilities discharging BA transport water develop a plan to minimize the discharge of pollutants by recycling as much BA transport water as practicable, back to the BA handling system.[46] Each facility would need to determine the amount of BA transport water that could easily be recycled and then develop a facility-specific BMP plan. The facility would then need to implement the plan, as well as review and revise the plan annually. In addition, as part of any permit renewal or re-opening, the facility would need to submit the facility-specific plan along with a certification that the plan complies with the requirements of 40 CFR § 423.13(k)(3) and is being implemented. This plan and certification, by a professional engineer, would need to be updated and provided to the permitting authority.

EPA's proposed amendments add section (k)(3) to 40 CFR §423.13. This new section spells out the requirements of the best management practices plan for BA transport water from low utilization boilers. The requirements include, among other things: identification of the low utilization coal-fired generating units that contribute bottom ash, a description of the existing bottom ash handling system, a detailed water balance specifying the volume and frequency of water additions and removals, measures that are to be employed by all facilities including daily or more frequent inspections of the BA transport water system, evaluation of options and feasibility for eliminating or minimizing discharges of BA transport water, a description of the BA recycle system, a schedule of implementing any changes to achieve the minimized discharge of BA transport water, a method for documenting and demonstrating the system is well operated and maintained, and weekly flow monitoring. In addition, EPA proposes adding section 423.19(d) regarding the certification process for BA transport water BMPs. This will require an initial and annual certification including certifications by a professional engineer.

As one can see, the requirements for the BMP are particularly onerous and will present a burden on low utilization boilers. The resources needed for design, construction, maintenance, developing plans for closure, conducting inspections, applying for certification, and more will impose significant costs on these facilities. In addition, requiring BMPs for low utilization facilities may create uncertainties that will result in inefficient or wasteful use of resources. As proposed, the BMP plan is akin to a BPJ approach, even though EPA's intent is to avoid case-bycase BPJ for the BA transport water subcategory. [47]

The Association would recommend amending the BMP plan by establishing a two-tier approach to establishing BAT for the low utilization subcategory. First, the permittee could install automated technology that would allow the permittee to automate control of the BA transport water system, using a programmable logic controller (PLC), for example. The automated technology would allow the operator to automatically control BA transport discharges. When maintenance is required, the operator will be able to override the automated system and manually control any discharges. Second, the permittee should prepare and implement a BMP plan consistent with the use of its existing technology, thus ensuring the BA transport maximum recycling requirement does not result in costs beyond the cost to install an automated operations technology.

44 33 U.S.C. §1314(e).
45 33 U.S.C. § 1314(b).
46 See 84 Fed. Reg. at 64,664.
47 84 Fed. Reg. at 64,639

23 BATW – Other Technologies

Commenter Name: Michael P. Alaimo
Commenter Affiliation: Clean Fuels Michigan, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8305-A1
Comment Excerpt Number: 3

Comment Excerpt:

Weakening of bottom ash limits is unjustified: EPA is proposing to allow power plants to discharge millions of gallons of contaminated bottom ash wastewater daily, up to 10 percent of a facility's total volume. The 2015 standards required coal plants to eliminate bottom ash wastewater discharges, which the agency determined plants could achieve by installing dry handling systems or by using closed-loop wet handling systems. This requirement meant that any water used to flush bottom ash had to be treated and reused, instead of pulling additional fresh water from a nearby river or lake and then discharging contaminated wastewater back into that body of water. Some power companies claim this 10 percent purge allowance is needed because it is too difficult and expensive to achieve zero discharge of bottom ash wastewater. But this claim is not grounded in reality. In 2015 EPA documented that more than 80 percent of all coal plants built in the last 20 years did not discharge bottom ash wastewater and that more than half of all older plants had already installed closed-loop or dry handling systems for bottom ash. The record clearly shows zero discharge technologies for bottom ash wastewater are available and achievable and therefore EPA must reaffirm the 2015 prohibition on these discharges.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 11

Comment Excerpt:

For bottom ash, EPA is proposing to weaken the 2015 nondischarge standard to once again allow wastewater discharges, even though completely dry handling systems are available and in place throughout the country.

Commenter Name: Jennifer Peters, et al.
Commenter Affiliation: Clean Water Action, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8462-A1
Comment Excerpt Number: 1

Comment Excerpt:

Weakening of bottom ash limits is unjustified: EPA is proposing to allow power plants to discharge millions of gallons of contaminated bottom ash wastewater daily, up to 10 percent of a facility's total volume. The 2015 standards required coal plants to eliminate bottom ash wastewater discharges, which the agency determined plants could achieve by installing dry handling systems or by using closed-loop wet handling systems. This requirement meant that any water used to flush bottom ash had to be treated and reused, instead of pulling additional fresh water from a nearby river or lake and then discharging contaminated wastewater back into that body of water. Some power companies claim this 10 percent purge allowance is needed because it is too difficult and expensive to achieve zero discharge of bottom ash wastewater. But this claim is not grounded in reality. In 2015 EPA documented that more than 80 percent of all coal plants built in the last 20 years did not discharge bottom ash wastewater and that more than half of all older plants had already installed closed-loop or dry handling systems for bottom ash. The record clearly shows zero discharge technologies for bottom ash wastewater are available and achievable and therefore EPA must reaffirm the 2015 prohibition on these discharges.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 36

Comment Excerpt:

IV BOTTOM ASH WASTEWATER

a. The Best Available Technology Standard Requires Non-Discharge Systems for Bottom Ash.

EPA's proposal to weaken the current non-discharge standard for bottom ash handling is incompatible with the Clean Water Act.

Bottom ash handling does not require generating any wastewater. Technology to remove bottom ash for dry landfill storage or recycling, such as Mechanical Drag and Conveyor systems, exists and is already in place at facilities around the country. According to EPA, over 75% of all facilities already use dry handling or closed-loop systems.[85] Moreover, these solutions need not rely on advanced technology: Santee Cooper has indicated in public meetings that it works with a local manufacturer who collects and trucks bottom ash off-site for use in cinder blocks. Thus, the best available technology is plainly a non-discharge system, and there is no justification for allowing the unnecessary bottom ash wastewater discharges proposed by EPA.

[85] See 84 Fed. Reg. at 64,634.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.

Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 28

Comment Excerpt:

In addition, EPA is again applying a legally incorrect test in evaluating whether dry handling systems should be BAT for bottom ash transport water discharges. As discussed in detail above (see Sections II – Legal Background and III – Southwestern Electric), BAT is not based on the “least costly” technology, but rather on the technology that is used at the best-performing plant in the industry that is both available and economically achievable. Because dry handling systems meet this test, as EPA itself acknowledges, EPA must continue to find them to be BAT for bottom ash transport water discharges (and has no basis to reverse its 2015 determination that they are BAT). For this additional reason, EPA must maintain the zero-discharge requirements for bottom ash transport water that it established in the 2015 ELG Rule.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 30

Comment Excerpt:

As EPA determined in 2015, the best-performing plants in the industry are achieving zero discharge of bottom ash transport water using either closed-loop wet systems or dry handling systems. In the record for the 2019 Proposal, EPA itself identified several examples of plants that are currently operating closed-loop wet systems to achieve zero discharge.[117] And as noted above, dry handling systems are currently in use at over 60% of power plants to achieve zero discharge.[118] For all of the reasons discussed above, EPA has no basis to reconsider its 2015 BAT determination for bottom ash transport water.

[117] See Sahu Expert Report at 6 (citing ERG, Review of Potential Closed-Loop Bottom Ash Transport Water Systems – DCN SE06493, Docket ID No. EPA-HQ-OW-2009-0819-7148 (Feb. 23, 2018)).
[118] See Proposed TDD at 3-9 Tbl. 3-3.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 122

Comment Excerpt:

As discussed above, the record shows that the Best Available Technology for treating bottom ash transport water is closed-loop handling with zero discharge, or dry handling.[420] In the absence of any evidence that meaningfully distinguishes between the treatment capabilities of low-utilization units and other units, this BAT determination would have to apply equally to the low-utilization units. As shown above, to the extent that the record illuminates bottom ash treatment cost, it shows that costs for units that run at a low capacity factor are not significantly higher than for other units.[421] More importantly, EPA provides no evidence that a zero-discharge standard for bottom ash could not be "reasonably borne" by the proposed subcategory.[422]

[420] See Section V - Bottom Ash.
[421] See Figure LU3.
[422] *Waterkeeper All., Inc. v. EPA*, 399 F.3d at 516; *Rybachek v. EPA*, 904 F.2d at 1290-91 (discussing this standard).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 43

Comment Excerpt:

Moreover, the current ELG rule already accounts for utilities' needs. As one industry publication explained in 2016, "After nearly five years of data collection, technology and cost evaluations, draft rulemaking, public comment and industry commentary, utilities now have the regulatory clarity necessary for compliance strategy development, technology selection, budgeting, permitting, scheduling and ultimately project implementation."[107] The ELG rule already provides flexibility for maintenance by, for example, excluding from the definition of transport water "low volume, short duration discharges of wastewater from . . . minor maintenance events (e.g., replacement of valves or pipe sections)."[108]

[107] Power Engineering, "Dry Ash Conversions" (Feb. 25, 2016), https://www.power-eng.com/2016/02/25/dry-ashconversions/#gref (Attachment 38).
[108] 40 C.F.R. § 423.11(p).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 44

Comment Excerpt:

EPA's proposed approach illustrates the importance of the BAT standard Congress created. Without the BAT standard, EPA—as it is trying to do here—could allow utilities' preferences to dictate the level of water pollution controls that would be applied. Average or even worse-performing plants could be used as the basis for setting nationwide effluent standards, just as EPA is proposing here.

Fortunately, that is not how the Clean Water Act works. It requires the BAT standards to be set based on the best-performing technology available. There are numerous facilities handling their bottom ash today without any discharges: this technology is plainly economically achievable and in place already. And indeed, EPA makes no attempt to argue that non-discharge bottom ash handling is unavailable or infeasible. EPA admits that "now over 75 percent" of all facilities have installed or are implementing non-discharge systems.[109] Moreover, EPA states that even more types of dry handling systems are now "available and in use" than in 2015, and that these new types of systems allow for more flexible installations to accommodate space constraints. [110] These developments only confirm that zero discharge, based on the performance of dry handling systems, is BAT for bottom ash.

Yet EPA is proposing to downgrade its BAT standard to different and far less effective technology—high recycle rate wet systems—as the "model treatment technology."[111] EPA is proposing to backslide from the admittedly "available and in use" non-discharge systems currently operating around the country that provide the basis for the BAT limitations under the current rule. There is no justification for this approach.

EPA should not be rewriting the rule to accommodate utility preferences, but rather requiring utilities to comply with the straightforward non-discharge standards that have been in place for years and are being met at facilities around the country.

[109] 84 Fed. Reg. at 64,634.
[110] Id.
[111] Id. at 64,663

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 45

Comment Excerpt:

2. EPA's Proposal Is Unnecessarily Harmful.

There is no need for this proposed weakening of the bottom ash standard.

Examples throughout the Southeast illustrate that utilities can successfully implement non-discharge systems. Georgia Power has committed to complying with the ELG Rule standard for Bottom Ash Transport Water per § 40 CFR 423.13(k) by November 1, 2020.[112] The company is installing completely dry Magaldi systems at Plant Scherer[113] and is also installing dry pneumatic systems at Bowen, Scherer, and Wansley.[114]

In April 2019, Santee Cooper's Cross Generating Station in South Carolina completed upgrades that allow all bottom ash to be handled dry.[115] And in 2017, Santee Cooper proposed to construct a zero discharge remote mechanical drag chain system to handle bottom ash at its Winyah Generating Station.[116]

Alabama Power already has installed a pneumatic ash extractor system with dedicated clinker grinder for handling bottom ash completely dry at its Miller power plant. And it has installed closed-loop systems at its Gaston and Barry facilities.[117]

And all coal-fired power plants in North Carolina have already stopped sluicing bottom ash to impoundments and have installed non-discharge systems. (These are primarily drag chain systems, although the Mayo facility has used a pneumatic bottom ash system for years.)[118] Duke Energy, which operates these facilities, requested compliance dates in each of its NPDES applications to allow it time to "optimize" its systems, and so far as we are aware, Duke Energy has never claimed to the state environmental agency that it was infeasible to achieve a true nondischarge system. Duke Energy and the other Southeastern utilities' success in installing and operating these systems makes clear that there is no cause to delay or weaken the non-discharge BAT requirement nationwide.

[113] Id. at 5.
[114] GPC ECS 2019, Attachment 21 at 65.
[115] Santee Cooper, Cross Bottom Ash Pond Closure Plan, at 3 (Aug. 21, 2019), available at https://www.santeecooper.com/About/CCR-Data-Rule/Cross/pdfs/Closure-and-post-closure-care/20190821-CGSBottom-Ash-Pond-Closure-Plan-Rev1.pdf (Attachment 39).
[116] WorleyParsons Group, Preliminary Engineering Report for Santee Cooper Winyah Station Low Volume Waste Ponds, at 4 (July 12, 2017) (Attachment 40).
[117] Alabama Power, Environmental Compliance Update (Dec. 12, 2018), at 25–34 (Attachment 41); Alabama Power, Preliminary Environmental Compliance Plan (Nov. 1, 2019), at 44 (excerpted in Attachment 42).
[118] See, e.g., NC DEQ, Fact Sheet for NPDES Permit Development, NPDES No. NC0038377, Duke Energy Progress, LLC, Mayo Steam Electric Generating Plant (Feb. 9, 2018), available at https://files.nc.gov/ncdeq/Water+Quality/NPDES+Coal+Ash/2014+Duke+Energy+Renewals+and+Modifications/Mayo/MAYO-38377--fact-sheet-2018.pdf (Attachment 43).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 47

Comment Excerpt:

None of these facts justifying the non-discharge BAT standard has changed. In light of the clear harms and risks posed by bottom ash transport water, and the fact that the best available technology is capable of eliminating all discharges of this wastewater, EPA's proposal to allow increased bottom ash wastewater discharges is unnecessarily harmful.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 15

Comment Excerpt:

V. THE PROPOSED WEAKENING OF BOTTOM ASH LIMITS IS UNJUSTIFIED.

EPA is proposing to reconsider its BAT determination for bottom ash transport water in the 2019 Proposal. As EPA acknowledges, it had previously determined that BAT for bottom ash transport water was zero discharge, based on the use of *either* a dry handling system or a closed loop system in which bottom ash is still handled wet but the transport water is completely recycled.[69] At the time that the 2015 ELG Rule was issued, EPA found that over fifty percent of power plants were already using dry handling or closed loop systems for their bottom ash transport water.[70] According to the 2019 Proposal, this number has now grown to over seventy-five percent of power plants already using these technologies.[71] More specifically, according to the Proposed TDD, over 60% of power plants are currently handling their bottom ash dry, approximately 20% are handling bottom ash wet in a system that recycles most or all of the transport water, and only approximately 20% are still handling their bottom ash wet in a system with limited or no recycling.[72]

EPA is now proposing to determine a new BAT for bottom ash transport water based on "high-recycle rate systems," which it describes as "partially closed loop" systems that are able to recycle their bottom ash transport water the majority of the time but require regular discharges of a purge stream for various reasons including maintenance and storm events. Specifically, EPA is proposing to allow power plants to operate wet bottom ash systems that would be allowed to purge up to 10% of their transport water by volume on a rolling monthly basis. This translates into allowing such systems to discharge up to their total volume three times in any given monthly period.

For the reasons described below, EPA's proposed redefinition of BAT for bottom ash transport water is meritless and contrary to the CWA. There is no basis in the record for EPA to reconsider its 2015 BAT determination that closed-loop wet bottom ash recycling systems and dry handling systems can achieve zero discharge of bottom ash transport water, as such systems remain available and economically achievable and are already widely in use at the best-performing plants in the industry.

[69] 84 Fed. Reg. at 64,634.
[70] Id.
[71] Id.
[72] Proposed TDD at 3-9 Tbl. 3-3.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 24

Comment Excerpt:

1.EPA acknowledges that closed-loop systems are available and economically achievable.

Closed-loop wet bottom ash recycling systems are still available and economically achievable for the industry, and nothing in the record of the 2019 Proposal requires EPA to go back on its prior determination that these systems are BAT for bottom ash transport water and can achieve zero discharge. EPA, in discussing the "challenges" that some plants face in achieving zero discharge of bottom ash transport water, concedes in the 2019 Proposal that the best-performing plants using wet bottom ash recycling systems "can likely eliminate such discharges with additional process changes and expenditures."[98] Moreover, EPA notes that it "does not find this higher cost [of fully closing the loop of a wet bottom ash recycling system] to be economically unachievable."[99]

[98] 84 Fed. Reg. at 64,635.
[99] Id.

Commenter Name: Mike Krumland
Commenter Affiliation: Nebraska Public Power District (NPPD)
Document Control Number: EPA-HQ-OW-2009-0819-8308-A1
Comment Excerpt Number: 6

Comment Excerpt:

NPPD questions the need to strictly regulate bottom ash transport water. Our testing indicates that the leachate from bottom ash is well below the current drinking water standards. This includes test results for Arsenic, Barium, Boron, and Selenium. We believe the zero discharge requirement of bottom ash transport water in the current rule is a regulatory overreach and is unnecessary.

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 12

Comment Excerpt:

Revisions to Effluent Discharge Limitations for BA Transport Water

Another major deficiency with the 2015 ELG rule is the imposition of an effluent discharge limitation that prohibits the discharge of any BA transport water into surface water. The imposition of a zero-discharge limitation means every coal-fired power plant must convert to dry ash handling or install a closed-loop wet ash handling system for transferring the BA from the boiler to CCR disposal facilities. In the case of the latter control option, the closed-loop system must be able to recycle 100 percent of the BA transport water in order to comply with the zero-discharge limitation imposed under the 2015 ELG rule.

Although technically possible, the recycling of all BA transport water is challenging to achieve for closed-loop systems. Furthermore, it overlooks the fact that small amounts of effluent are discharged in most of the closed-loop wet ash systems upon which a zero discharge limitation for BA transport water was set in the 2015 ELG rules.[7] In light of this fact, wet ash handling systems for BA transport are, in reality, "partially closed" rather "closed looped," and they must operate as partially closed systems "due to small discharges associated with stormwater, and water chemistry imbalances including acidity and corrosiveness, scaling, and fines build-up."[8] Furthermore, the total elimination of all discharges for many coal-fired facilities would require extensive process changes, increased costs and, in many cases, be difficult to achieve.[9] As a result, the cost of achieving this last increment of reduction in BA transport water would be disproportionately high with negligible benefits to human health and the environment.

[7] 84 Fed. Reg. at 64,634-35.

[8] In particular, the proposed ELG rule identified many of the measures that electric utility owners and operators would have to implement in order to eliminate all discharges from existing wet ash recycle systems. These measures include "adding additional treatment chemicals (caustic) to manage acidity or other chemicals to control alkalinity, making use of reverse osmosis filters to treat a slip stream of the recycled water to remove dissolved solids, adding polymer to enhance settling and remove fine particles ('fines'), and building storage tanks to hold water during infrequent maintenance or precipitation events." 84 Fed. Reg. at 64,634-35.

[9] Ibid.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 39

Comment Excerpt:

IX. Completely Closed-Loop Recirculating BATW Systems Are Not Economically Reasonable in Light of Their Higher Costs in Relation to Marginal Pollutant Reductions Achieved.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 45

Comment Excerpt:

Additionally, EPA also should conclude that completely closed-loop BATW systems are not economically achievable in light of their much higher costs and only slight marginal pollutant reductions as compared to high recycle rate systems.[59]

[59] In doing so, EPA should revise its statement that it "does not find this higher cost [of complete recycle BATW systems as compared to high recycle rate systems] to be economically unachievable…." 84 Fed. Reg. at 64,635. EPA should conclude that the costs compared to the marginal additional pollutant reductions rules out choosing complete recycle BATW systems as BAT.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 37

Comment Excerpt:

VII. Completely Closed-Loop Recirculating BATW Systems Require More Equipment than Closed-Loop Recirculating Systems with a Purge Stream.

During its reconsideration of the 2015 rule, EPA reevaluated its choice of dry handling or completely closed-loop recirculating BATW systems as the model technology for BATW. From an engineering perspective, the Agency determined that its 2015 model technology for the zero discharge limit was likely not sufficient for all facilities. See 84 Fed. Reg. at 64,635.

The Agency acknowledges that "some facilities with wet ash removal systems … in many cases must operate as high recycle rate systems" instead of zero discharge systems (84 Fed. Reg. at 64,635) and suggests that facilities unable to operate in zero discharge mode could add "additional treatment chemicals (caustic) to manage acidity or other chemicals to control alkalinity, make use of reverse osmosis filter to treat a slip stream of the recycled water to remove dissolved solids, add polymer to enhance settling and removal of fine particulates ('fines') and build storage tanks to hold water during infrequent maintenance or precipitation events." Id. at 64,635.

For the Proposed Rule, EPA's model technology for high recycle rate BATW systems with a purge consists of an RMDS, sump, recycle pumps, a chemical feed system, and a semi-dry silo for each generating unit. Supplemental TDD at 5-33. But EPA's model technology for a completely closed-loop BATW system also includes a reverse osmosis system and a surge tank, pumps, and piping needed to hold and recirculate the reverse osmosis distillate or BATW back to the plant for reuse. Id. at 5-47. Because a completely closed-loop system would have to add additional equipment (whether that is a reverse osmosis system or something else, such as clarifiers, additional chemical treatment, and overflow tanks) to be able to operate without any purge stream, EPA correctly increased its costs for the zero discharge technology.[36]

Industry experience with completely closed-loop RMDSs bears out the need for additional technology and/or treatment steps. At Plant Wansley, Georgia Power constructed an RMDS in 2016-2019. The components of the system include drag chain conveyors, caustic feed skids, concrete storage bunkers, sumps, high pressure recirculation pumps, and balance of plant scope including electrical and utility services. But to close the loop, Georgia Power added the following additional treatment steps in addition to the RMDS described in the 2015 ELG TDD:

polymer injection system, lamella clarifiers within the RMDS troughs, overflow tanks, surge tanks, and containment around the bottom ash hopper. Also, additional piping, valves, pumps, and instrumentation were added to tie in BATW purge to the FGD scrubber for reuse. Furthermore, the RMDS included 100 percent redundant equipment trains for maintenance and reliability purposes.

These additional components, of course, add to the cost of a complete recycle system. But there are other complications that also add costs for ensuring that every gallon of BATW, except those associated with minor maintenance, is recirculated. For instance, Georgia Power had to find a way to contain BATW that would be released when the bottom ash hopper must be opened to service the grinders. In order to ensure a complete recycling of the BATW during this major maintenance event, the plant constructed containment walls around each hopper, along with new tanks and sumps to collect and recirculate BATW back into the system. This costly modification was necessary to prevent BATW from commingling with other wastewaters (not subject to a zero discharge limit) and being discharged as a low volume waste.

[36]EPA, although it included a reverse osmosis system as part of its zero discharge option within the Proposed Rule, does not appear to have accounted for the costs of management and disposal of the brine from this system and did not include costs for containment of BATW released from the bottom ash hopper when the grinders within the hopper need maintenance.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 41

Comment Excerpt:

B. The Much Higher Costs of Complete Recycle BATW Systems Are not Justified.

Comparing EPA's industry-wide costs for the baseline option (BATW complete recycle) to Option 3 (BATW with a purge stream, without the low utilization boiler exemption)[46] demonstrates the significant cost differential between these options. The comparison of the two options isolates the cost savings attributable to allowing the BATW purge stream.

EPA's Estimated Costs of Implementation of Bottom Ash Transport Water (in millions of pre-tax 2018 dollars)[47]

Regulatory Option	Number of Plants	Capital Costs	Annual O&M Costs
Baseline (BATW complete recycle)	94	$1,680	$96.1
Option 3 (BATW with purge)	94	$1,330	$80.4

Thus, EPA estimates a savings of approximately $350 million in capital costs and an annual savings of about $16 million in O&M costs based on allowing the 10 percent by volume discharge allowance.

In comparison to EPA's estimates, EPRI's estimated costs are much higher. EPRI estimated costs on the basis of 10 plants that have either retrofitted to zero discharge of BATW or retrofitted to partially closed-loop BATW systems. EPRI's RMDS capital costs are based on total engineering, procurement, and construction cost project examples for 10 plants,[48] with a range of MWs capacities from five utility companies.[49] EPRI then compared its list of plants to EPA's list of plants and duplicated EPA's list, with just a few adjustments to account for additional unit retirements.[50] EPRI also assigned MDSs and RMDSs to the units subject to BATW retrofits in the same manner as EPA.[51] EPRI then estimated total industry-wide costs to be as follows:

EPRI's Estimated Costs of Implementing Bottom Ash Transport Water Retrofits (in millions of mid- 2018 dollars)[52]

Regulatory Option	Capital Costs ($M)	O&M Costs ($M per year)
Convert from Wet to Dry Bottom Ash Handling	$3,103	$140

While EPA's "baseline" assumes achievement of "zero discharge" for all plants subject to retrofitting, EPRI's costs are based on a mix of plants designed to achieve zero discharge and other partially closed-loop BATW systems. But given that EPRI has virtually matched its universe of plants and units to EPA's list (except for a few additional retirements, which would lessen industry costs), and has assigned MDSs and RMDSs according to EPA's approach, it is clear that overall industry costs are significantly higher as calculated by EPRI. EPRI's capital costs are 1.8 times EPA's capital costs, and its O&M costs are 1.4 times higher.

[46] Using Option 3 for this comparison is appropriate because doing so eliminates any cost savings attributable to the special provisions for units that may qualify for the low utilization boiler exemption in Option 2 and thus makes a better comparison for this limited purpose.
[47] Adapted from the Supplemental TDD, Table 5-10 at 5-60.
[48] None of the plants on whose real-world experience EPRI based its BATW cost estimate had all of the technology components potentially required by EPA's proposal – e.g., "installed spares, redundancies, maintenance tanks, and other secondary bottom ash equipment." Proposed § 423.13(k)(2)(i)(A)(1).
[49] EPRI 2020 Comments, Appendix F at F-3.
[50] See id. at F-1.
[51] Id. at F-3.
[52] Id. at F-1.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 18

Comment Excerpt:

1.6 BATW Zero-Discharge Implementation Costs

EPA's cost analysis for its proposal is also highly suspect and inflated because it presumes that BATW will need to undergo reverse osmosis treatment in order for its proper management. This is overkill and adds considerably to the estimated costs by EPA. It is my opinion that routing small amounts (i.e., less than 2%—which could be even less with proper BMPs) to FGDs or storing such waters for reuse with simple treatments such as pH balance and addition of anti-scaling agents should be sufficient. Of course precipitation should not be allowed to enter the BATW waters as part of any BMPs or formulation of any purge allowance. EPA does not assume such reasonable actions in its cost analysis. Instead, as discussed in the TDD, Section 5.3.3, EPA states the following as part of "additional zero discharge costs":

The cost methodology for all rMDS systems includes chemical addition equipment to manage pH of the transport water so that potential corrosion or scaling is minimized, and to allow for polymer addition if needed to enhance removal of suspended solids. For the zero discharge technology option, the EPA has also estimated costs for plants to install more robust treatment should it be necessary to prevent the buildup of dissolved solids to levels that may interfere with effectively controlling corrosion and scale formation by the chemical addition processes. This additional treatment entails the use of reverse osmosis to treat a slipstream of transport water. The data in the record indicates that most plants would not experience such TDS-related interferences or that managing alkalinity would resolve potential issues and obviate the need for RO treatment. However, since the EPA does not have sufficient plant-specific data to determine which plants may need RO treatment, the EPA's cost methodology assumes that all new and current rMDS systems would install RO treatment to ensure the plant could manage the closed-loop recycle for the bottom ash transport water.[45] (emphasis added)

In other words, even though EPA admits that "most plants" would not need to install expensive RO systems to achieve zero discharge, nonetheless it has assumed that RO systems would be required in order to manage the closed loop BATW. This is an unreasonable assumption. As I have noted earlier, the small purge volumes that are associated with continuous purges (after BMPs are implemented) as well as from occasional maintenance (after storage) can be managed via FGD systems or boiler feed water systems at all plants and there should be no need to consider RO systems to manage these purges. EPA's skewed assumption that RO systems would be required is fundamentally wrong. Thus, all costs derived from this assumption (including the strange and unsupported reference to "$43 million per year" costs in the preamble,[46]) are unnecessary.

[45] TDD at 5-45.
[46] 84 Fed. Reg. at 64,635.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 12

Comment Excerpt:

EPA's selection of reverse osmosis (RO) technology for eliminating a purge is technically challenging and overly complex when deploying a fully closed-loop remote bottom ash dewatering system. RO also does not address all sources of purge water that could occur, making a no-discharge solution unworkable.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 56

Comment Excerpt:

8.2 **EPA's selection of RO technology for eliminating a purge is technically challenging and costly when deploying fully closed-loop remote bottom ash dewatering. Use of RO does not address all sources of purge.**

EPA estimated an annualized cost for the industry as a whole of $43 million per year to go from remote bottom ash loop with purge to completely closed loop [EPA 2019a]. The EPA's approach to estimating was to assume the plant would add an RO system to treat the purge water and reuse the permeate in a closed loop. The EPA estimated an annualized cost of $43 million per year cost to go from a remote bottom ash high recycle system with purge to completely closed loop [EPA, 2019a]. EPA's approach to cost estimating was to assume the plant would add an RO system to treat the purge water and reuse the permeate in a closed loop. EPA provides a cost formula and curve for the RO system. It is not clear how the EPA estimated cost to manage the brine produced from the RO treatment, which could be a significant cost. Presumably the brine would need to be encapsulated and disposed of. Additionally, RO does not address modifications necessary to eliminate unintentional purges that could confound compliance with a no discharge of bottom ash transport water requirement. For example, purges due to leaks may require expensive infrastructure modifications to contain leaks. For example, certain activities associated with the bottom ash system may involve flows that are currently routed to a station sump. In theory, these flows could be captured to prevent them from entering the station sump, but depending upon the plant's configuration, that may be infeasible or expensive to accomplish. On the other hand, rerouting the station sump to the bottom ash system is not recommended because it introduces even more flows and possibly other constituents such as oil and grease.

EPRI researched the challenges of high-recycle rate bottom ash systems in 2019 [EPRI, 2019] by interviewing seven plants to identify the cause(s) of having to purge from their system. EPRI then did a high-level cost estimate for eliminating the purge for the seven case study plants, as is shown in Table 8-1. There is a large range of costs to go from having a purge to having no purge. These do not account for additional challenges that may require additional treatment or a purge to counteract, specifically water quality issues from higher recirculation rates. The median annualized cost would be roughly $650,000/year.

Table 8-1
EPRI case study costs compared to individual plant estimates for costs to close the loop

Description of Approach to Eliminate Purge	Plant	Capital Cost	O&M	Total Annualized Cost
Addition of a new treatment system for non-transport wastewaters currently treated in the bottom ash dewatering system (equalization tanks, clarifiers, dewatering building, and chemical feed systems)	F	$17,000,000	$470,000	$2,100,000
Treatment system for purge to FGD scrubber (pH adjustment and a pressure filter)	G	$4,600,000	$270,000	$700,000
Addition of maintenance tanks and associated return pumps	A	$6,200,000	$73,000	$660,000
Addition of maintenance tanks and associated return pumps	E	$6,000,000	$75,000	$640,000
Addition of maintenance tanks and associated return pumps	D	$5,500,000	$75,000	$590,000
Addition of heat exchangers to provide water temperatures needed for economizer ash hopper cooling water	C	$230,000	$51,000	$73,000
Addition of caustic feed system and pH monitoring controls to control acidity	B	$31,000	$6,000	$9,000

$ = U.S. dollars, pre-tax in 2018 dollars

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 25

Comment Excerpt:

Separately in the 2019 Proposal, EPA estimates that "the costs of fully closing the loop" in closed-loop systems "to be $43 million in after-tax costs, above and beyond the costs of the systems themselves."[100] This assumption is inflated, however: as EPA acknowledges in the Proposed TDD, it is assuming for the 2019 Proposal that any remote bottom ash recycling systems would need to install additional wastewater treatment – a reverse osmosis system – in order to meet zero discharge requirements.[101]

This assumption is unreasonable, for at least three reasons. First, as discussed above, EPA's record does not establish that *any* plant has a need for a bottom ash purge allowance, let alone a 10% volumetric purge allowance, given that the purported causes of such purges can all be feasibly addressed so as to eliminate any need for discharges of the purge stream.

Second, EPA generalizes this cost assumption to all wet bottom ash recycling systems, without acknowledging that its record (as noted above) is limited to remote systems. There is no analysis in the record of under-the-boiler systems, nor does EPA appear to have even distinguished between remote and under-the-boiler systems in determining which plants would likely discharge a bottom ash purge stream.[102]

Third, as EPA concedes in the Proposed TDD, "[t]he data in the record indicates that most plants would not experience" the water quality issues that it believes would require use of reverse osmosis treatment.[103] In other words, even taking EPA's analysis of the record at face value, the Agency itself acknowledges that reverse osmosis treatment would not be required at most plants in order to fully close the loop of a wet bottom ash recycling system. And yet despite this acknowledgement that most plants will not actually need to install reverse osmosis treatment, EPA nevertheless assumes that all plants would install such systems for purposes of developing its cost estimate.[104] EPA explains this assumption – which has the effect of dramatically increasing the cost estimate to fully close the loop at an average plant – by stating only that it "does not have sufficient plant-specific data to determine which plants may need [reverse osmosis] treatment."[105] EPA's assumption that all plants will install an expensive additional treatment system that even the Agency itself believes most plants will not need is plainly irrational. Even taking the rest of the analysis for the 2019 Proposal at face value, this assumption in and of itself renders EPA's rejection of wet closed-loop systems as BAT arbitrary and capricious.

[100] Id.
[101] See Proposed TDD at 5-45.
[102] See, e.g., ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option –DCN SE07090, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019) (documenting EPA'sunit-level assumptions about technology selection without distinguishing between remote and under-the-boiler wet recycling systems for bottom ash).
[103] See Proposed TDD at 5-45.
[104] Id.
[105] Id.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 8

Comment Excerpt:

1.3 BATW Zero Discharge Is Clearly Feasible

It is worth noting at the outset that zero discharge of BATW is clearly achievable and in place at many U.S. coal-fired power plants.

First, this includes plants that dry-handle bottom ash, avoiding the use of BATW altogether – thereby achieving "zero" discharge. As shown in Table 3-3 in the TDD provided earlier, this includes 173 plants/284 units. Yet, in the proposed rule, EPA has explicitly set aside any considerations that this is a perfectly reasonable approach to achieve zero discharge.[12] Thus, EPA has implicitly reversed its determination from 2015 that dry handling is available and economically achievable under the BAT standard. EPA's own record in this matter contains discussions with vendors such as Magaldi[13] and Delta Ducon[14] who have such dry-ash handling systems. While these types of systems may not work in all instances, depending on the space available under the boiler, EPA has made no efforts in this proposal to collect the data on such boiler space limitations – thereby identifying candidate plants/units where such dry system installations are possible. It is unreasonable to assume that none of the units at the 90+ plants that are the subject of EPA's focus in this proposed rule with regards to BATW are space limited and cannot therefore install dry systems. In fact, there is every reason to believe that most boilers do have the space below the boiler to accommodate dry systems.[15] In any case, by not providing this crucial information, EPA's proposal presumptively jumps ahead to "flexibility" where none may be needed.

Second, even for plants that use water to convey bottom ash, EPA has itself identified examples of plants that achieve complete recycle or zero discharge. These include: EME Homer City Generation L.P. (Plant ID 1381), Shiras (Plant ID 5711), Genoa #3 (Plant ID 7175).[16]

Any reasonable interpretation of BAT would arrive at the conclusion that these plants and how they have achieved complete recycle and therefore zero discharge, should be the basis for how BATW should be handled fleet-wide. Thus, EPA's proposed redefinition of BAT to include a 10% volumetric purge makes no sense under the BAT standard, when there are numerous better performing plants. It is a "solution" in search of a problem.

[12] "Although the technology basis includes dry handling, the limitation is based on the necessary purge volumes of a wet, high recycle rate BA system." 84 Fed. Reg. at 64,663 n.97.
[13] ERG Telephone Call Record with Magaldi North America Re: Discussion of Magaldi Bottom Ash Handling Systems (Feb. 14, 2018) (EPA-HQ-OW-2009-0819-7695).
[14] ERG Telephone Call Record with Delta Ducon Re: Potential Changes to the Ash Handling Part of the Steam Electric ICR (Jan. 28, 2010) (EPA-HQ-OW-2009-0819-1202).
[15] See id. Per a conversation between ERG and Delta Ducon in January 2010 (i.e., roughly 10 years ago), the "vast majority of plants would have the vertical space required to retrofit a boiler with a dry bottom ash handling system."
[16] ERG, Review of Potential Closed-Loop Bottom Ash Transport Water Systems, at 1 (Feb. 23, 2018) (EPA-HQOW-2009-0819-7148).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 41

Comment Excerpt:

As for maintenance costs associated with operating a truly closed loop system, the proposed weakening of the BAT standard is not needed. EPA admits that facilities using wet systems can take "relatively straightforward steps" to address maintenance, stormwater, and buildup issues in order to avoid discharging polluted wastewater into the nation's waterways— but EPA is not requiring them to do so, and instead proposes to weaken the rule.[101] This approach is unjustified.

And while EPA claims other facilities may need to make "more extensive process changes,"[102] this claim also does not justify departing from the BAT standard. Utilities have been on notice for years that they must achieve zero discharge, and some chose to implement wet rather than dry systems in order to do so. If some of this technology does not work as specified, resulting in additional compliance costs, that is a matter for those utilities to resolve with their vendors and/or their insurance providers; the public should not be forced to accept less effective wastewater treatment at those facilities. Still less should the public be forced to accept a nationwide rule that allows all facilities to pollute more based on less effective treatment at a few poorly performing facilities.

[101] See id.
[102] See id.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 27

Comment Excerpt:

2.E*ven if it was true that closed-loop systems could not achieve zero discharge, BAT should still be set at zero discharge due to dry handling systems being available and achievable.*

EPA's purported reconsideration of its 2015 BAT determination for bottom ash transport water also fails because dry handling systems are an available, economically achievable means for the industry to achieve zero discharge. EPA even notes in the 2019 Proposal that there have been advances in dry handling technologies since it issued the 2015 ELG Rule.[110] In particular, EPA points to two new technology options, in addition to the mechanical drag systems that were the technology basis for the zero-discharge bottom ash limits in the 2015 rule, that are "now available and in use at some facilities": pneumatic systems and submerged grinder conveyors.[111] EPA notes that these new systems would "at some facilities . . . have costs similar to recirculating wet systems that would require a purge."[112] EPA claims, however, that it "did not have cost information to determine" for the 2019 Proposal "the subset of facilities for which new dry systems might be least costly."[113]

This is a fatal gap in EPA's analysis. EPA acknowledges that dry handling systems are available to the industry, and it previously determined in the 2015 ELG Rule that one type of dry handling system was economically achievable and thus BAT. Conversion to dry handling may be cost-effective even for plants that have already installed closed-loop systems,[114] yet EPA appears not to have considered this possibility at all in connection with the 2019 Proposal. An expert report submitted during the comment period for the 2013 proposed ELG rule found that dry handling systems are more cost-effective, have lower space requirements, save energy, produce more valuable ash that is easier to manage, eliminate many operation and maintenance issues, and are safer as compared to wet systems (including closed-loop systems).[115] Instead of weakening its 2015 BAT determination, EPA must thoroughly analyze whether dry handling systems can be feasibly adopted at any plants that may experience challenges in achieving zero discharge through closed-loop wet systems. EPA's failure to do a plant-by-plant analysis for the 2019

Proposal of which plants could feasibly install new dry handling systems is arbitrary and capricious.[116]

[110] 84 Fed. Reg. at 64,634.
[111] Id.
[112] Id. at 64,435 n.41.
[113] Id.
[114] See Expert Report of Dr. Phyllis Fox, at 16, Docket ID No. EPA-HQ-OW-2009-0819-4704 (Sept. 19, 2013 ("Fox Expert Report") ("[T]he literature on conversion from wet to zero discharge bottom ash handling systems indicates dry bottom ash handling systems pay for themselves in a very short period, as they significantly reduce the O&M costs of bottom ash handling, offsetting the capital investment. In addition, they generate an ash stream that is much more marketable than a wet bottom ash stream.").
[115] See id. at 15-22.
[116] See Sahu Expert Report at 6. EPA also failed to analyze the costs of dry handling systems for the 2015 ELG rule. As an expert report submitted during the comment period for the 2013 proposed ELG rule found, "[w]hile it may not be feasible to convert 100% of the subject units to dry systems (as it is likely not feasible to convert 100% of subject units to [mechanical drag systems] or remote [mechanical drag systems]), the EPA should have evaluated dry options to bound the range of costs and impacts, or
should have assumed that a portion of the fleet would convert to dry." Fox Expert Report at 15.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 38

Comment Excerpt:

VIII. Submerged Grinder Conveyors, an Emerging Technology, are Not BAT.

EPA notes some "advances" in dry bottom ash handling systems since the 2015 rule. 84 Fed. Reg. at 64,634. In particular, EPA points to the emergence of submerged grinder conveyors as "available" technology being used at some facilities. Id. While this technology is in use at two facilities, it is not universally applicable, and, therefore, should not be the basis for setting nationally applicable BAT requirements. [37] The submerged grinder conveyor essentially replaces the bottom ash sluice piping with a clinker grinder and mechanical conveyors to dewater and remove bottom ash from beneath the boiler house. Industry experience with this technology is very limited at this point, so questions remain about performance, reliability and operating costs for the wide variety of physical and operating conditions at other plants in the category. For example, because this technology is so new, it is difficult to say with certainty how well it performs across the industry under difficult and/or extreme conditions. However, it is clear that it is not universally applicable, for the following reasons:

- It is feasible only for smaller units (generally less than 550 MW).
- If the boiler is below grade, it will be difficult to apply this technology, because there needs to be sufficient room underneath the existing bottom ash hopper for the grinder conveyor.
- There must be enough open space for the grinder conveyor to dewater ash and to exit the boiler house. At some sites, there will be space constraints in these areas.

- The system's chain conveyor is much smaller and lighter duty than chains for an MDS or RMDS. Therefore, it is better suited for units with low utilization, where performance and maintenance issues are less problematic.

[37] UWAG believes submerged grinder conveyors should not be the technology basis for BATW limits. But this emergent technology can be considered a type of dry handling equipment that facilities may choose to install to meet BATW limits.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 42

Comment Excerpt:

Despite its reliance on the "process changes" element of the BAT analysis, EPA has not attempted to show that implementing or maintaining a closed-loop system cannot be done. Nor has EPA attempted to argue that the cost of compliance is unachievable. Instead, EPA merely makes vague reference to its desire to give utilities "flexibilities,"[103] a concept that cannot dictate the BAT standard. Instead, it appears that EPA's "process changes" rationale is really just an attempt to lower costs for utilities. In essence, EPA is attempting to rewrite the BAT requirement to accommodate utility preferences to save money at the expense of the nation's waters. For example, EPA's 2017 Belews Creek site visit notes state that Duke Energy would prefer to "bleed" off a portion of the bottom ash wastewater to deal with fines. However, EPA also reports that SCE&G/Dominion's Wateree plant in South Carolina "recently installed lamella plate clarifiers to remove solids recirculating within the plant's remote SFC system."[104] EPA should maintain a standard that ensures Duke Energy and other utilities implement this type of solution rather than discharging large volumes of contaminated wastewater.

Similarly, Duke Energy has claimed a tax credit for operating a "dry bottom ash handling" system at Belews Creek, stating that this system "is used for pollution abatement" "100%" of the time.[105] Yet the EPA Belews Creek site visit notes state that Duke Energy prefers to let the system "rest" 10% of the time.[106] EPA should require Duke Energy to use the system to its full pollution control capacity — all the more so because Duke is charging its customers and receiving tax credits for using this system 100 percent of the time.

[103] Id.
[104] Belews Creek Site Visit Notes, supra n.26, at 3.
[105] Duke Energy, Application for Certification of Pollution Control Facility (July 19, 2018) (Attachment 37).
[106] Belews Creek Site Visit Notes, supra n.26, at 3.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 16

Comment Excerpt:

First, as noted previously, BMP plans should be required for all plants in order to ensure compliance with zero discharge requirements for BATW. They should cover steps that a plant should take to minimize routine purges and leaks from the BATW system and they should address elimination of any precipitation or major maintenance related BATW.

24 BATW – General

No comment excerpts were received on this topic.

25 Non-Water Quality Environmental Impacts

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 8

Comment Excerpt:

5. "Paste" is defined in the proposed rule as "A substance containing solids in a fluid which behaves as a solid until a force is applied which causes it to behave like a fluid". "Paste Landfill" is defined in the rule as "A landfill which receives any paste designed to set into a solid after the passage of a reasonable amount of time".

Paste delivered to Paste Landfills by pipeline is a future-generation brine disposal technology currently at R&D stage. On the other hand, "Grout" can be defined as "A solid material which encapsulates brine concentrated from wastewater and sequesters the metals and other pollutants present in the brine". Grout can be transported by conveyors or trucks or other bulk containers. Grout can be safely disposed in a CCR Landfill without concerns of "leachate blowout" described in the rule, or grout may be beneficially used at the power plant without the passage of time.

a. Landfills on site at power plants and at third-party sites are designed to receive solid CCR by conveyors or trucks. Current landfilling operations are not equipped to handle paste pumped from the end of a pipe even if the paste can pass TCLP and paint filter tests. Operators are trained and skilled at operating heavy mobile equipment to properly place large quantities of bulk materials. Most of them have no experience handling paste or knowing how to do so. On the other hand, fully cured grout that arrives in chunks can be received, handled and placed in the same manner and using the same equipment and procedures as CCR. After the industry gains experience with grout, the transition to paste disposal may be easier when paste technology has reached the same technology readiness level.

b. The costs of landfill operations will likely increase when third-party operators are asked to change the scope of their services to include paste. Many power plant CCR disposal operations are outsourced to third-party contractors. The contracts anticipate receipt and disposal of solid bulk material to be delivered by conveyors, trucks, railcars or barges rather than paste from the end of a pipe. Contractors are very likely to demand higher prices and absolution for any risks associated with transporting and handling paste. The inclusion of grout with CCR in landfill operations would not change the scope of contractors' services, add risk to their operations, or justify higher contract prices.

c. The EPA's technical analysis of paste technology should consider electric energy required to pump paste a long distance compared to the fuel required by trucks. The electric energy to pump paste is produced by processes that are about 35% energy efficient and grout can be hauled by trucks that are about 50% energy efficient. Grout may also be moved by conveyor belt along with CCR. Moreover, in the future grout and CCR may be transported with electric vehicles if emissions are concerning.

d. The EPA's technical analysis should consider beneficial uses of cement-like grout as flowable fill or pond liner, not just solid waste for disposal.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 9

Comment Excerpt:

6. The EPA's rationale for paste technology is that it (1) minimizes fly ash requirements and (2) results in less CO2 emissions by pumping paste to a landfill rather than hauling grout in trucks.

a. Fly ash is not a scarce commodity

i. The proposed rule states that "over one half of the FA (fly ash) generated by coal-fired facilities is being sold for beneficial uses rather than disposed of". Some of the remainder (almost 10 million tons annually) is not sold because it doesn't meet the required quality specifications, or it's too far from the market demand, or the expected revenue from the sales is not an adequate incentive to pay for the handling cost.

ii. Some of the present beneficial uses of FA might incorporate brine without impacting product quality or cost. Some examples of beneficial uses that may use brine in to replace fresh water include:

1. Flowable fill (over 80,000 tons of FA in 2018)
2. Structural fill (over 1.5 million tons of FA in 2018),
3. Waste stabilization (over 900,000 tons of FA in 2018)

4. CCR pond closure (over 600,000 tons of FA in 2018).

iii. Many millions of tons of fly ash remain in ponds and landfills and can be reclaimed, processed and sold if and when the market demands it.

b. The EPA estimates CO2 emissions that result from producing, transporting and disposing of paste with unverified physical and chemical properties are more art than science. Any estimate should include CO2 emissions associated with energy and raw materials required to manufacture, deliver, and install pipe, make and transport the paste, and special handling required for paste disposal.

c. When CCR are disposed in landfills, they are dampened by about 15-20% water (by weight) to prevent dust and to improve handleability. Brine can be used to replace fresh water for FA dampening. Grout may contain as much as 40% brine by weight so making grout from FA destined for disposal has the net effect of replacing plant water with brine and doubling the amount of liquid in the mixture. Power plant water consumption for CCR dampening is eliminated by grout making and no free liquid arrives with CCR at the landfill; the landfill receives grout as a dry bulk solid.

26 EA – Scope

No comment excerpts were received on this topic.

27 EA – General Impacts and Exposure Pathways

Commenter Name: Tara A. Rocque, Washington University Interdisciplinary Environmental Clinic
Commenter Affiliation: Labadie Environmental Organization ("LEO"), Missouri Chapter of the Sierra Club
Document Control Number: EPA-HQ-OW-2009-0819-8303-A1
Comment Excerpt Number: 1

Comment Excerpt:

Missouri is a very coal dependent state and thus has many CCR disposal ponds which discharge significant volumes of CCR wastewater.[1] Without exception, all of the CCR disposal ponds in Missouri are leaking and contaminating groundwater and surface water. Without good reason, the proposed amendments to the ELG rule would allow this contamination to continue damaging Missouri's water quality and threatening the health of Missouri's citizens. EPA should withdraw its proposed amendments and allow the 2015 ELG rule to be fully implemented on its original schedule.

The proposed amendments to the ELG Rule will allow continued contamination of major rivers in Missouri.

1 U.S. Energy Information Administration states that "More coal is consumed for electricity generation in Missouri than in all but one other state – Texas." See https://www.eia.gov/state/analysis.php?sid=MO . Data from U.S. EIA, Annual Coal Report 2017, November 2, 2018, Table 26.

Commenter Name: Tara A. Rocque, Washington University Interdisciplinary Environmental Clinic
Commenter Affiliation: Labadie Environmental Organization ("LEO"), Missouri Chapter of the Sierra Club
Document Control Number: EPA-HQ-OW-2009-0819-8303-A1
Comment Excerpt Number: 3

Comment Excerpt:

As an example, Ameren-Missouri operates four coal fired power plants that surround the St. Louis metropolitan area.[8] All four plants have ash ponds which discharge contaminants such as arsenic, lithium, selenium and boron into major rivers[9] and are leaking these same contaminants into these rivers' alluvial groundwater resources.[10] The total design discharge capacity for bottom ash wastewater from these four facilities is 140.25 million gallons per day (MGD).[11] Under the 2015 ELG Rule, this entire wastewater stream would be eliminated. However, under EPA proposed amendments, these four facility could continue to discharge up to a combined 14 MGD of contaminated wastewater.[12] Allowing contaminated wastewater to continue discharging to Missouri's waters compounds these facilities' environmental impact since all four facilities have ash ponds that are leaking contaminants directly into alluvial groundwater.[13] The alluvial groundwater flows into the adjacent surface water, adding these contaminants to the river's flow. Groundwater sampling at Ameren's Rush Island Energy Center showed concentrations of arsenic up to 25 times the federal drinking water standard and boron concentrations nearly 8 times Missouri's water quality standard for groundwater.[14] The proposed amendment would allow this additional wastewater discharge on top of the contamination already flowing via groundwater into Missouri's rivers.

EPA's proposed amendment would directly and adversely affect Missouri's drinking water resources.

EPA's proposed amendments to the ELG Rule are problematic because most utilities in Missouri discharge bottom ash and fly ash wastewater into major rivers like the Missouri River and Mississippi River which are sources of drinking water. Forty-three percent of Missouri's citizens rely on the Missouri River as a surface water source for drinking and over half of the state's population use the Missouri River surface water and its alluvial groundwater for drinking water.[15]

Multiple ash ponds located on the banks of the Missouri River both leak contaminants into alluvial groundwater and discharge ash pond wastewater into the river. The largest ash pond discharge into the Missouri River is from the Ameren Labadie Energy Center. The Labadie ash ponds have a design discharge of 57.8 MGD. If EPA's proposed amendments to the ELG Rule are implemented, the Labadie ash ponds could continue to discharge up to 5.78 MGD. Multiple public drinking water intakes are downstream from the Labadie Energy Center. These intakes supply water to St. Charles County, St. Louis County and St. Louis City residents.[16]

Multiple ash ponds are also located on the banks of the nation's largest river, the Mississippi River which is also a source of drinking water for many Missouri citizens. These ponds are located at Ameren's Sioux Energy Center, Meramec Energy Center and Rush Island Energy Center and Associated Electric Cooperative Inc.'s (AECI) New Madrid Power Plant. The Sioux Energy Center in particular has ash pond discharges upstream of the City of St. Louis' drinking water intake.[17] Allowing discharges to continue, even at reduced flow, will continue to put the drinking water of Missouri's citizens at risk.

EPA's proposed amendments for bottom ash transport water will effectively length the lifetime of ash ponds and extend the life of their wastewater discharges. In combination with leaking ash ponds, these unnecessary discharges will continue threating human health and the environment. LEO and the Sierra Club request that EPA rescind its misguided proposed amendment to the ELG Rule.

8 See Ameren's fact sheet listing four coal fired power plants in the St. Louis area: https://www.ameren.com/-/media/missouri-site/files/aboutus/amerenmissourifactsheet.pdf.
9 See Ameren-Missouri's NPDES Permits: 1) Labadie Energy Center, MO-0004812, effective August 1, 2015, Outfall #002; 2) Rush Island Energy Center, MO-0000043, effective March 2, 2019, Outfall #002; 3) Meramec Energy Center, MO-0000361, effective January 1, 2018, Outfall #003; and 4) Sioux Energy Center, MO-0000353, Outfall #002, effective April 1, 2017. The Labadie Energy Center ash ponds discharge to the Missouri River. The Sioux and Rush Island Energy Centers' ash ponds discharge to the Mississippi River and the Meramec Energy Center ash ponds discharge to the Meramec River above its confluence with the Mississippi River.
10 For example, see 2018 Annual Groundwater Monitoring and Corrective Action Report, LCPA Surface Impoundment, Labadie Energy Center, Golder Associates Inc., January 31, 2019, Tables 3-Table 8. Ameren's other groundwater monitoring and corrective action reports showing exceedances of state and federal standards are available at https://www.ameren.com/company/environment-and-sustainability/managing-coal-combustion/ccrcompliance-reports .
11 See Ameren-Missouri's NPDES Permits: 1) Labadie Energy Center, MO-0004812, effective August 1, 2015, Outfall #002; 2) Rush Island Energy Center, MO-0000043, effective March 2, 2019, Outfall #002; 3) Meramec Energy Center, MO-0000361, effective January 1, 2018, Outfall #003; and 4) Sioux Energy Center, MO-0000353, Outfall #002, effective April 1, 2017. The design discharge capacities for ash ponds at Labadie, Rush Island, Sioux and Meramec are 57.8 MGD, 43.1 MGD, 15.8 MGD and 23.55 MGD, respectively. The total design discharge capacity is 140.25 MGD.
12 140.25 MGD * 0.10 = 14 MGD
13 See Ameren's 2018 groundwater monitoring and corrective action reports at https://www.ameren.com/company/environment-and-sustainability/managing-coal-combustion/ccr-compliancereports
14 2017 Annual Groundwater Monitoring Report, RCPA Surface Impoundment, Rush Island Energy Center, Golder Associates, Inc., January 30, 2018, Table 2. The federal Maximum Contaminant Level for arsenic is 10 micrograms per liter (see https://www.epa.gov/ground-water-and-drinking-water/national-primary-drinking-water-regulations) and Missouri's water quality standard for boron is 2,000 micrograms per liter (see 10 CSR 20-7.031 Table A).
15 See Missouri Department of Natural Resources, Water Protection Program - Public Drinking Water Branch at https://dnr.mo.gov/env/wpp/drinkingwaterweek/index.html.
16 The City of St. Louis operates two drinking water plants. The Chain of Rocks Plant is located on the Mississippi River approximately 5 miles source of the confluence of the Missouri and Mississippi Rivers. The Howard Bend Treatment Facility is located on the Missouri River. The combined capacity of the two plants is 380 MGD. See

https://www.stlouis-mo.gov/government/departments/public-utilities/water/water-treatment.cfm. See also Missouri American Water 2018 Annual Water Quality Report, page 2, available at http://www.amwater.com/ccr/stlouisregion.pdf . Missouri American Water uses water from both the Missouri and Meramec Rivers for customers in St. Louis, St. Charles and Jefferson Counties.

17 The City of St. Louis operates two drinking water plants. The Chain of Rocks Plant is located on the Mississippi River approximately 5 miles source of the confluence of the Missouri and Mississippi Rivers. The Howard Bend Treatment Facility is located on the Missouri River. The combined capacity of the two plants is 380 MGD. See https://www.stlouis-mo.gov/government/departments/public-utilities/water/water-treatment.cfm.

Commenter Name: Michael P. Alaimo
Commenter Affiliation: Clean Fuels Michigan, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8305-A1
Comment Excerpt Number: 1

Comment Excerpt:

Steam electric power plants, mostly coal plants, are responsible for the majority of arsenic, lead, mercury, selenium and other toxic metals discharged into our nation’s rivers, lakes, and streams every year. These plants also discharge high levels of nutrients, bromide, and other harmful pollutants. Power plant wastewater discharges have made it unsafe to eat fish from many rivers, contaminated the lakes and rivers where people swim, damaged aquatic ecosystems, and created treatment challenges for drinking water systems.

If finalized as proposed, EPA’s revisions would gut long overdue protections established in 2015 that prohibited the dumping of coal ash wastewater into our nation’s waters and imposed stringent limits on toxic metals and other pollutants in scrubber sludge discharges. Weakening these standards is unjustified and will result in more pollution in our nation’s precious water resources. In Michigan, emissions and wastewater discharges from coal plants have led to fish advisories and contaminated waterways across the state. We therefore urge EPA to abandon its misguided proposal to weaken the 2015 standards.

Commenter Name: Angie Rosser
Commenter Affiliation: West Virginia Rivers Coalition (WV Rivers), et al.
Document Control Number: EPA-HQ-OW-2009-0819-8321-A1
Comment Excerpt Number: 2

Comment Excerpt:

Steam electric power plants, mostly coal plants, are responsible for the majority of arsenic, lead, mercury, selenium and other toxic metals discharged into our nation’s rivers, lakes, and streams every year. West Virginia currently has five power plants discharging into the state’s rivers that would be impacted by the relaxation of the regulations; Fort Martin Power Station, Mount Storm Power Station, John E. Amos Power Station, and the Mitchell Plant. Additionally, the Cardinal Plant located in Ohio discharges to the Ohio River which forms the boundary between WV and

OH and impacts WV residents. EPA's proposal to weaken the regulations for these facilities are unjustified and unnecessarily puts the environment and public's health at risk.

EPA is proposing to allow power plants to discharge higher amounts of arsenic and selenium in Flue Gas Desulfurization wastewater. The Fort Martin Power Plant is already exceeding the discharge limitations for selenium. Fort Martin's National Pollutant Elimination System (NPDES) permit WV0004731 allows an average monthly discharge of selenium at concentrations of 0.0101 mg/L and a maximum discharge of 0.0202 mg/L. On the August 31, 2019 sampling event at Outlet 0002, discharges of selenium were recorded at an average concentration of 0.021706 mg/L and a maximum concentration of 0.022788 mg/L. The receiving stream, Crooked Run, is already on the 303(d) list for biological impairments. Allowing Fort Martin to discharge more selenium would further impair this already damaged stream. EPA should be reducing selenium discharges, not allowing power plants to discharge more of these toxic metals into our waterways.

EPA is proposing to allow power plants to discharge contaminated bottom-ash wastewater, up to 10% of a facility's total volume. Fort Martin produced 8,340 tons in 2018. Bottom ash contains high concentrations of heavy metals such as arsenic, barium, beryllium, boron, cadmium, chromium, thallium, selenium, molybdenum and mercury that are toxic to aquatic life and public health. Zero discharge technologies for bottom ash wastewater are available and achievable; therefore, EPA has no justification to allow power plants to discharge more of these toxic pollutants into our waterways.

Commenter Name: Anonymous
Commenter Affiliation:
Document Control Number: EPA-HQ-OW-2009-0819-8408
Comment Excerpt Number: 2

Comment Excerpt:

Finally, this rule recognizes in Section XII(D) that there are several grave non-monetized benefits, including health and other effects from changes in NOX and SO2 air emissions; changes in certain noncancer health risks (e.g., effects of cadmium on kidney functions and bone density); impacts of pollutant load changes on threatened and endangered species habitat; and ash marketing changes. The quick discussion and dismissal of these serious issues should prompt the agency to reconsider how it assessed the benefits of this rule. Moreover, the global environmental and health impact of this rule is conspicuously missing from this proposed rule as well.

Commenter Name: Colton Fagundes
Commenter Affiliation: American Sustainable Business Council

Document Control Number: EPA-HQ-OW-2009-0819-8463-A1
Comment Excerpt Number: 1

Comment Excerpt:

The 2015 ELG standards were the first-ever national water pollution limits to control the amount of heavy metals that were being dumped into our nation's water supply. If some of these standards had not been delayed by the EPA in 2017 at the behest of industry, they would have prevented 1.4 billion pounds of pollution from being dumped in our waterways every year.

Since these restrictions were delayed, much of our nation's water supply now contains entire populations of fish that are unsafe for human consumption. In 2015 the EPA estimated that roughly 30 million people have eaten fish contaminated by coal plants, pollution had made over 4,000 miles of rivers unsafe for use as a drinking water source or for fishing, and had made over 6,000 miles of rivers unsafe for children to use for recreational fishing, primarily from high mercury levels.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 1

Comment Excerpt:

Steam electric power plants, mostly coal plants, are responsible for the majority of arsenic, lead, mercury, selenium and other toxic metals discharged into our nation's rivers, lakes, and streams every year. These plants also discharge high levels of nutrients, bromide, and other harmful pollutants. Power plant wastewater discharges have made it unsafe to eat fish from many rivers, contaminated the lakes and rivers where people swim, damaged aquatic ecosystems, and created treatment challenges for drinking water systems.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 26

Comment Excerpt:

Selenium is toxic to fish, and it can be toxic to humans. Scientific studies on human health effects have shown low levels of environmental exposure can cause severe cardiomyopathy, and high exposures can have adverse effects on the endocrine system, particularly the thyroid, and increase the risk of type 2 diabetes, some types of cancers such as melanoma and lymphoid cancers, and nervous system disturbances.[41] Especially because selenium is known to have a toxic effect on fish and human health at low levels, EPA must retain the more protective limits set forth in the 2015 Rule.

[41] See, e.g., Marco Vinceti, et al, Health risk assessment of environmental selenium: Emerging evidence and challenges (Review), 15 MOLECULAR MED. REP. 3323, 3324 (2017), available at https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5428396/pdf/mmr-15-05-3323.pdf (Attachment 2).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 27

Comment Excerpt:

Selenium contamination has been an issue across the Southeast. In past decades in North Carolina, selenium pollution from the Belews Creek site has devastated the fish population in Belews Lake, eliminating 95 percent of fish species present in Belews Lake. In 2007, EPA classified Belews Lake a "proven ecological damage case" due to selenium poisoning from leaking coal ash pits at the Belews Creek plant.[42] Selenium bioaccumulates and persists in the environment, and birds that feed in Belews Lake continue to experience adverse effects from selenium poisoning. According to Duke Energy's own studies, selenium concentrations in fish tissue continue to be two to three times higher downstream of the Belews Creek coal ash site, compared to upstream concentrations.[43]

[42] Excerpt of EPA Office of Solid Waste, Coal Combustion Waste Damage Case Assessments at 25 (July 9, 2007) (Attachment 3).
[43] Excerpt of Duke Energy, Belews Creek Steam Station, 2013 Dan River Summary at 2-3 (Dec. 2014) (Attachment 4).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 28

Comment Excerpt:

Also in North Carolina around the Cliffside plant, researchers at Appalachian State University have detected high levels of heavy metals, including selenium, in the tissue of fish caught near the plant in the Broad River.[44] They studied fish caught upstream, downstream, and at the pipe where Duke Energy dumps polluted water into the river. The researchers discovered the fish downstream have accumulated highly elevated levels of heavy metals, including arsenic, lead, selenium, and zinc. At a public meeting held by NC DEQ in January 2019, the lead researcher, Dr. Shea Tuberty, implored DEQ to consider these findings in its coal ash pond closure determinations. Dr. Tuberty mentioned selenium as an example. Upstream, the level of selenium accumulated in the fish was 2 parts per million (ppm, or 2mg/kg dry body weight), but at the weir dam next to the ash ponds, it was higher, ranging from 1-5 ppm. Downstream of a drainage pipe from the ash pond, the fish tissue accumulation was higher still: 10 ppm of selenium, which he warned is a level of high concern. At that level of contamination, he said, EPA recommends people should limit consumption of those fish to four meals per month to prevent non-cancer health effects.[45] As Dr. Tuberty said, the truth about whether the water is contaminated is in the animals we eat. The fish tissue study indicates that discharge at Cliffside, which includes FGD wastewater, is polluting the water.

[44] See Alexandra Gibbs, et al, Heavy Metal Accumulation in Fish of the Broad River Near the Rogers Energy Complex Coal Ash Basins (Attachment 5).
[45] U.S. Environmental Protection Agency, Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories, Vol. 2 (Nov. 2000), available at https://www.epa.gov/sites/production/files/2015-06/documents/volume2.pdf (Attachment 6).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 46

Comment Excerpt:

In addition, the harms of EPA's proposed change are serious and apparent, as EPA itself has acknowledged previously. Coal ash wastewater, including bottom ash transport water, is a major source of dangerous pollutants. As EPA explained in the 2015 rulemaking:

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 55

Comment Excerpt:

In 2016, a team of Duke University researchers performed seep, groundwater and surface water sampling at 15 coal ash sites in 5 states, including unlined impoundments at Georgia Power's Plant Branch and Plant Arkwright. [143] This published, peer-reviewed study concluded that there was "strong evidence for the leaking of coal ash ponds to adjacent surface water and shallow groundwater" – "systemic evidence" of toxic pollution at "levels above drinking water and ecological standards..." [144] The CCR Leak Study concluded that unlined impoundments at Georgia Power's Plant Branch was polluting nearby Lake Sinclair with boron and strontium, contaminating groundwater with one or more toxic pollutants at levels exceeding the groundwater protection standard or other health-based standards. [145]

In Virginia, Dominion Energy's Chesterfield Units 5 and 6 run so infrequently that Dominion has started to describe them as "peaker" units; both units will likely be eligible for the proposed exception. The 15 million tons of ash in Chesterfield's two impoundments are immediately adjacent to a public park, Dutch Gap Conservation Area. An expert analyzed surface water and sediment sampling data and concluded that there are elevated cancer risks and other health hazards for recreational visitors to Dutch Gap.[146] Eliminating this leaking, unlined pit should be required by EPA under the Clean Water Act, but if this proposal were the only authority in place, Dominion would be allowed to continue operating it. Fortunately, Virginia has enacted legislation requiring this impoundment (and all of Dominion's unlined impoundments in the state) to be fully excavated to dry, lined landfill storage or recycling.[147] But this site illustrates the serious consequences of EPA's approach.

[143] See Jennifer Harkness, Barry Sulkin and Avner Vengosh, Evidence for Coal Ash Ponds Leaking in Southeastern United States, Envtl. Science and Tech., (June 10, 2016) ("CCR Leak Study") (Attachment 50); see also Tim Lucas, Coal Ash Ponds Found to Leak Toxic Chemicals: Long-lasting contamination won't be cleaned up by ash removal alone, DUKE TODAY (June 10, 2016), available at https://today.duke.edu/2016/06/ashpondleaks (summarizing CCR Pond Leaking Study, reporting that "In all of the investigated sites, we saw evidence of leaking" and "high levels of contaminants" in polluted surface waters, according to Duke geochemistry and water quality professor Avner Vengosh) (Attachment 51).
[144] See Attachment 50 at 6583 (Abstract).
[145] See id. at 6587.
[146] See Dr. Carolyn L. Fordham, PhD., Terra Technologies Environmental Services, Human Health and Ecological Risk Assessment, Chesterfield Power Station Ash Ponds (Nov. 9, 2018) (Attachment 52).
[147] 2019 Va. Acts Ch. 651.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 60

Comment Excerpt:

The Cumberland Plant is the largest coal-fired power plant in TVA's fleet.[156] The Cumberland Plant is located in Cumberland City, Tennessee, at the confluence of Wells Creek and a stretch of the Cumberland River known as Lake Barkley and is upstream from cherished recreational and wildlife areas in Tennessee, including Barkley Wildlife Management Area, Cross Creeks National Wildlife Refuge, and Land Between the Lakes National Recreation Area.[157] The Cumberland River/Lake Barkley (river miles 90.3–108) is included on Tennessee's list of Known Exceptional Tennessee Waters and Outstanding National Resource Waters due to the Cross Creeks National Wildlife Refuge and the presence of state-endangered lake sturgeon.[158] Several drinking water intakes are also located downstream from the Cumberland Plant.[159]

The Cumberland Plant burns millions of tons of coal annually, resulting in approximately one million tons of coal combustion residuals (coal ash) waste generated annually and, in 2016, an average of 2,097 million gallons of wastewater each day.[160] In the 2019 Proposal, EPA asserts that the Cumberland Plant is the single largest source of FGD wastewater in the country, accounting for "approximately one-sixth to one-seventh of all industry FGD wastewater flows."[161]

In 1994, TVA chose to install a scrubber that discharges large amounts of FGD wastewater after a single use rather than recycling the wastewater in its industrial process.[162] TVA's stated reasons for selecting a high-flow, once-through scrubber included "the ability to burn a wide range of coals" and "the lack of any wastewater treatment effluent limitations for metals."[163] Like most other coal plants, prior to the adoption of the 2015 ELG Rule, TVA's NPDES permit included no limits on toxic pollutants like mercury, arsenic, and selenium.[164] For this reason, shifting toxic pollution from the air to the water made economic sense for TVA in 1994.

For decades, TVA has been discharging massive quantities of toxic pollutants into state designated Exceptional Tennessee Waters on the Cumberland River. A 2016 report published by the Environmental Integrity Project identified the Cumberland Plant as the worst mercury polluter among coal plants nationwide.[165] Mercury is a neurotoxin that accumulates in fish and can cause damage to a person's nervous, digestive, and immune systems.[166] The report, based on information provided by TVA to the federal EPA and available to the public in the Toxics Release Inventory, found that in 2015, TVA dumped 120 pounds of mercury generated at the Cumberland Plant into the Cumberland River.[167] The same report identifies the Cumberland Plant as the second-worst selenium polluter among coal plants nationwide.[168] Like mercury, selenium also accumulates in fish. Selenium can cause damage to a person's circulatory system.[169] In 2015, TVA dumped 6,000 pounds of selenium generated at the Cumberland Plant into the Cumberland River.[170] Although TVA's subsequent Toxic Release Inventory reporting indicates a reduction in mercury discharges, in 2018, TVA continued to dump 60 pounds of mercury into the river.[171] In 2016, the last year TVA reported, the utility discharged 1,300 pounds of selenium from the Cumberland Plant.[172]

[156] Tenn. Valley Auth., Cumberland Fossil Plant, https://www.tva.gov/Energy/Our-PowerSystem/Coal/Cumberland-Fossil-Plant (2,470 megawatt generating capacity) (Attachment 54).
[157] Southern Envtl. Law Ctr., Cumberland Fossil Plant: Managed Natural Resource Areas Downstream, May 22, 2015 (Attachment 55).
[158] Tenn. Dep't Envt. & Conservation, Exceptional Tennessee Waters & ORNWs in Tennessee: Cumberland River (Lake Barkley), http://tdec.tn.gov:8080/pls/enf_reports/f?p=9034:34304:0: (last visited Apr. 25, 2019) (Attachment 56).
[159] Southern Envtl. Law Ctr., Tennessee Valley Authority Coal Ash Sites and Downstream Drinking Water Intakes, June 30, 2016 (Attachment 57).
[160] Tenn. Valley Auth., Cumberland Fossil Plant Coal Combustion Residuals Management Operations Environmental Impact Statement (Apr. 2018), at S-1 ("The plant consumes an average of 5.6 million tons of coal annually and produces approximately 1 million tons of CCR each year.") (Attachment 58); Tenn. Valley Auth., Cumberland Fossil Plant (CUF)—NPDES Permit No. TN0005789—Updated Permit Renewal Application (Aug. 1, 2016) (reporting an average flow of 2,096.987 mgd from Outfall 2, which includes discharge from internal Outfall 001) (Attachment 59).
[161] 84 Fed. Reg. at 64,638, n.54.
[162] Tenn. Valley Auth., Cumberland Fossil Plant—NPDES Permit No. TN0005789—TVA Request for Alternative Effluent Limitations for Wet Flue Gas Desulfurization System Discharges Based on Fundamentally Different Factors Pursuant to 33 U.S.C. § 1311(n), at 4 (Apr. 28, 2016) (Attachment 60) ("TVA FDF Request").
[163] Id. at 5.
[164] Tenn. Dep't of Envtl. & Conservation, Cumberland Fossil Plant, NPDES Permit No. TN0005789 Part A, 2 (effective date January 1, 2008) (Attachment 61).

[165] Environmental Integrity Project, Toxic Wastewater from Coal Plants, at 16 (Aug. 2, 2016), http://environmentalintegrity.org/wp-content/uploads/Toxic-Wastewater-from-Coal-Plants-2016.08.11-1.pdf (Attachment 62) ("EIP Report"); see also Mark Hicks, Cumberland City Plant Rated Worst Mercury Polluter, Clarksville Leaf-Chronicle (Aug. 11, 2016), http://www.theleafchronicle.com/story/news/2016/08/11/cumberlandfossil-plant-rated-worst-mercury-polluter-us/88559336/ (Attachment 63).
[166] EIP Report, Attachment 62, at 8 (Aug. 2, 2016).
[167] Id. at 16.
[168] Id.
[169] Id. at 8.
[170] Id. at 16.
[171] EPA, TRI On-Site and Off-Site Reported Disposed of or Otherwise Related (In Pounds) Trend Report for Facilities in US TVA Cumberland Fossil Plant (TRI ID 37050STVCM815CU) for Mercury Compounds Chemical US 2000-2018 (Nov. 12, 2019), https://enviro.epa.gov/triexplorer/release_trends?tri=37050STVCM815CU&p_view=TRYR&trilib=TRIQ1&sort=_VIEW_&sort_fmt=1&state=All+states&county=All+counties&chemical=N458&industry=ALL&core_year=&tab_rpt=1&FLD=AIRLBY&FLD=E1&FLD=E2&FLD=E3&FLD=E4&FLD=E41&FLD=E (Attachment 64).
[172] EPA, TRI On-Site and Off-Site Reported Disposed of or Otherwise Related (In Pounds) Trend Report for Facilities in US TVA Cumberland Fossil Plant (TRI ID 37050STVCM815CU) for Selenium Compounds Chemical US 2000-2018 (Nov. 12, 2019), https://enviro.epa.gov/triexplorer/release_trends?tri=37050STVCM815CU&p_view=TRYR&trilib=TRIQ1&sort=_VIEW_&sort_fmt=1&state=All+states&county=All+counties&chemical=N725&industry=ALL&core_year=&tab_rpt=1&FLD=AIRLBY&FLD=E1&FLD=E2&FLD=E3&FLD=E4&FLD=E41&FLD=E (Attachment 65).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 134

Comment Excerpt:

The Cumberland Plant is the largest coal-fired power plant in TVA's fleet.[459] The Cumberland Plant is located in Cumberland City, Tennessee, at the confluence of Wells Creek and a stretch of the Cumberland River known as Lake Barkley and is upstream from cherished recreational and wildlife areas in Tennessee, including Barkley Wildlife Management Area, Cross Creeks National Wildlife Refuge, and Land Between the Lakes National Recreation Area.[460] The Cumberland River/Lake Barkley (river miles 90.3–108) is included on Tennessee's list of Known Exceptional Tennessee Waters and Outstanding National Resource Waters due to the Cross Creeks National Wildlife Refuge and the presence of state-endangered lake sturgeon.[461] Several drinking water intakes are also located downstream from the Cumberland Plant.[462]

The Cumberland Plant burns millions of tons of coal annually, resulting in approximately one million tons of coal combustion residuals (coal ash) waste generated annually and, in 2016, an average of 2,097 million gallons of wastewater each day.[463] In the 2019 Proposal, EPA asserts that the Cumberland Plant is the single largest source of FGD wastewater in the country, accounting for "approximately one-sixth to one-seventh of all industry FGD wastewater flows."[464]

In 1994, TVA chose to install a scrubber that discharges large amounts of FGD wastewater after a single use rather than recycling the wastewater in its industrial process.[465] TVA's stated reasons for selecting a high-flow, once-through scrubber included "the ability to burn a wide range of coals" and "the lack of any wastewater treatment effluent limitations for metals."[466] Like most other coal plants, prior to the adoption of the 2015 ELG Rule, TVA's NPDES permit included no limits on toxic pollutants like mercury, arsenic, and selenium.[467] For this reason, shifting toxic pollution from the air to the water made economic sense for TVA in 1994.

For decades, TVA has been discharging massive quantities of toxic pollutants into state-designated Exceptional Tennessee Waters on the Cumberland River. A 2016 report published by the Environmental Integrity Project identified the Cumberland Plant as the worst mercury polluter among coal plants nationwide.[468] Mercury is a neurotoxin that accumulates in fish and can cause damage to a person's nervous, digestive, and immune systems.[469] The report, based on information provided by TVA to the federal EPA and available to the public in the Toxics Release Inventory, found that in 2015, TVA dumped 120 pounds of mercury generated at the Cumberland Plant into the Cumberland River.[470] The same report identifies the Cumberland Plant as the second-worst selenium polluter among coal plants nationwide.[471] Like mercury, selenium also accumulates in fish. Selenium can cause damage to a person's circulatory system.[472] In 2015, TVA dumped 6,000 pounds of selenium generated at the Cumberland Plant into the Cumberland River.[473] Although TVA's subsequent Toxic Release Inventory reporting indicates a reduction in mercury discharges, in 2018, TVA continued to dump 60 pounds of mercury into the river.[474] In 2016, the last year TVA reported, the utility discharged 1,300 pounds of selenium from the Cumberland Plant.[475]

[459] Tenn. Valley Auth., Cumberland Fossil Plant, https://www.tva.gov/Energy/Our-Power-System/Coal/Cumberland-Fossil-Plant (2,470 megawatt generating capacity) (attached).
[460] S. Envtl. Law Ctr., Cumberland Fossil Plant: Managed Natural Resource Areas Downstream, May 22, 2015 (attached).
[461] Tenn. Dep't Envt. & Conservation, Exceptional Tennessee Waters & ORNWs in Tennessee: Cumberland River (Lake Barkley), http://tdec.tn.gov:8080/pls/enf_reports/f?p=9034:34304:0: (last visited Apr. 25, 2019) (attached).
[462] S. Envtl. Law Ctr., Tennessee Valley Authority Coal Ash Sites and Downstream Drinking Water Intakes, June 30, 2016 (attached).
[463] Tenn. Valley Auth., Cumberland Fossil Plant Coal Combustion Residuals Management Operations Environmental Impact Statement (Apr. 2018), at S-1 ("The plant consumes an average of 5.6 million tons of coal annually and produces approximately 1 million tons of CCR each year.") (attached); Tenn. Valley Auth., Cumberland Fossil Plant (CUF) – NPDES Permit No. TN0005789 – Updated Permit Renewal Application (Aug. 1, 2016) (reporting an average flow of 2,096.987 mgd from Outfall 2, which includes discharge from internal Outfall 001) (attached).
[464] 84 Fed. Reg. at 64,638 n.54.
[465] Tenn. Valley Auth., Cumberland Fossil Plant – NPDES Permit No. TN0005789 – TVA Request for Alternative Effluent Limitations for Wet Flue Gas Desulfurization System Discharges Based on Fundamentally Different Factors Pursuant to 33 U.S.C. § 1311(n), at 4 (Apr. 28, 2016) (attached).
[466] Tenn. Valley Auth., Cumberland Fossil Plant – NPDES Permit No. TN0005789 – TVA Request for Alternative Effluent Limitations for Wet Flue Gas Desulfurization System Discharges Based on Fundamentally Different Factors Pursuant to 33 U.S.C. § 1311(n), at 5 (Apr. 28, 2016) (attached).
[467] Tenn. Dep't of Envtl. & Conservation, Cumberland Fossil Plant, NPDES Permit No. TN0005789 Part A, 2 (effective date Jan. 1, 2008) (attached).
[468] Environmental Integrity Project, Toxic Wastewater from Coal Plants, at 16 (Aug. 2, 2016), http://environmentalintegrity.org/wp-content/uploads/Toxic-Wastewater-from-Coal-Plants-2016.08.11-1.pdf (attached); see also Mark Hicks, Cumberland City Plant Rated Worst Mercury Polluter, ClarksvilleLeaf-Chronicle (Aug. 11, 2016), http://www.theleafchronicle.com/story/news/2016/08/11/cumberland-fossil-plant-rated-worst-

mercury-polluter-us/88559336/ (attached).
[469] Environmental Integrity Project, Toxic Wastewater from Coal Plants, at 8 (Aug. 2, 2016), http://environmentalintegrity.org/wp-content/uploads/Toxic-Wastewater-from-Coal-Plants-2016.08.11-1.pdf (attached).
[470] Environmental Integrity Project, Toxic Wastewater from Coal Plants, at 16 (Aug. 2, 2016), http://environmentalintegrity.org/wp-content/uploads/Toxic-Wastewater-from-Coal-Plants-2016.08.11-1.pdf (attached).
[471] Environmental Integrity Project, Toxic Wastewater from Coal Plants, at 16 (Aug. 2, 2016), http://environmentalintegrity.org/wp-content/uploads/Toxic-Wastewater-from-Coal-Plants-2016.08.11-1.pdf (attached).
[472] Environmental Integrity Project, Toxic Wastewater from Coal Plants, 8 (Aug. 2, 2016), http://environmentalintegrity.org/wp-content/uploads/Toxic-Wastewater-from-Coal-Plants-2016.08.11-1.pdf (attached)
[473] Environmental Integrity Project, Toxic Wastewater from Coal Plants, 16 (Aug. 2, 2016), http://environmentalintegrity.org/wp-content/uploads/Toxic-Wastewater-from-Coal-Plants-2016.08.11-1.pdf (attached).
[474] EPA, TRI On-Site and Off-Site Reported Disposed of or Otherwise Related (In Pounds) Trend Report for Facilities in US TVA Cumberland Fossil Plant (TRI ID 37050STVCM815CU) for Mercury Compounds Chemical US 2000-2018 (Nov. 12, 2019), https://enviro.epa.gov/triexplorer/release_trends?tri=37050STVCM815CU&p_view=TRYR&trilib=TRIQ1&sort=_VIEW_&sort_fmt=1&state=All+states&county=All+counties&chemical=N458&industry=ALL&core_year=&tab_rpt=1&FLD=AIRLBY&FLD=E1&FLD=E2&FLD=E3&FLD=E4&FLD=E41&FLD=E (attached).
[475] EPA, TRI On-Site and Off-Site Reported Disposed of or Otherwise Related (In Pounds) Trend Report for Facilities in US TVA Cumberland Fossil Plant (TRI ID 37050STVCM815CU) for Selenium Compounds Chemical US 2000-2018 (Nov. 12, 2019), https://enviro.epa.gov/triexplorer/release_trends?tri=37050STVCM815CU&p_view=TRYR&trilib=TRIQ1&sort=_VIEW_&sort_fmt=1&state=All+states&county=All+counties&chemical=N725&industry=ALL&core_year=&tab_rpt=1&FLD=AIRLBY&FLD=E1&FLD=E2&FLD=E3&FLD=E4&FLD=E41&FLD=E (attached).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 185

Comment Excerpt:

A. The Impacts of Toxic Heavy Metals Such as Cadmium, Mercury, and Selenium on Aquatic Life and Species Health are Significant

1. Cadmium

Cadmium pollution is toxic to many aquatic species and can be toxic to mammals and birds. It can cause toxicity through both chronic exposure and consumption of prey in which the metal has bioaccumulated. Specifically, cadmium can negatively impact the survival, growth, reproduction, development, behavior, and metabolism of fresh water-dependent, endangered, and threatened species, especially during early life stages. Synergistic and additive effects may also occur when heavy metals are mixed with other toxic chemicals.

Cadmium pollution from mining activities in southern Arizona near the habitat of the endangered Chiricahua leopard frog, for example, was identified by FWS as one of the main contributing factors to the decline of this species.[699] Likewise, cadmium is known to disrupt the endocrine functions of Atlantic salmon and other listed salmonids in the Pacific Northwest and is negatively impacting the reproductive capabilities of these endangered species.[700] Cadmium pollution negatively impacts the shortnose sturgeon's physiological processes and ability to swim.[701]

Further, as the recovery plan for the Cumberland and Tennessee River mussels explain, many endangered freshwater mussels are "among the most intolerant organisms to heavy metals," and "[c]admium appears to be the heavy metal most toxic to mussels."
[702] Cadmium has been directly correlated with the decline of the dwarf wedgemussel,[703] and FWS has identified cadmium as "acutely toxic" to the winged mapleleaf mussel.[704] Alarmingly, FWS has noted in another recovery plan that "[v]irtually nothing is known about the sublethal impacts in mussels to long-term exposure to metals at low concentration" and that "[s]ublethal effects are frequently observed at concentrations only one-half the lethal concentrations, which indicates freshwater mussels become stressed at metal concentrations much lower than those reported in acute toxicity tests."[705] Thus, even small amounts of cadmium may have disproportionately adverse effects for endangered species – effects that are especially pronounced in aquatic species.[706]

[699] U.S. Fish & Wildlife Serv., Chiricahua Leopard Frog: Final Recovery Plan, at 23 (2007) (attached).
[700] NOAA's Nat'l Marine Fisheries Serv. & Ne. Region, U.S. Fish & Wildlife Serv., Final Recovery Plan for the Gulf of Maine Distinct Population Segment of Atlantic Salmon, at 1-38, 1-39 (2005) (attached).
[701] U.S. Dep't of Commerce, Nat'l Oceanic & Atmospheric Admin., Nat'l Marine Fisheries Serv., Final Recovery Plan for the Shortnose Sturgeon, at 49 (1998) (attached).
[702] U.S. Fish & Wildlife Serv., Recovery Plan for Cumberland Elktoe, Oyster Mussel, Cumberlandian Combshell, Purple Bean, and Rough Rabbitsfoot, at 37 (2004) (attached); see also U.S. Fish & Wildlife Serv. et al., Scaleshell Mussel Recovery Plan, at 19, 26 (2010) (attached); see also U.S. Fish & Wildlife Serv., Recovery Plan for Endangered Fat Threeridge, Shinyrayed Pocketbook, Gulf Moccasinshell, Ochlockonee Moccasinshell, Oval Pigtoe, and Threatened Chipola Slabshell, and Purple Bankclimber, at 33-35 (2003) (attached).
[703] U.S. Fish & Wildlife Serv., Dwarf Wedge Mussel Recovery Plan, at 14 (1993) (attached).
[704] U.S. Fish & Wildlife Serv., Winged Mapleleaf Mussel Recovery Plan, at 9 (1997) (attached).
[705] U.S. Fish & Wildlife Serv., Higgins Eye Pearlymussel Recovery Plan: First Revision, at 12 (2004) (attached).
[706] U.S. Fish & Wildlife Serv., Alabama Cave Shrimp Recovery Plan, at 11 (1997) (attached).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 186

Comment Excerpt:

2. Mercury

Mercury, particularly in the chemical form methylmercury, is a toxic pollutant that poses a substantial threat to human health and the health of water-based ecosystems. Danger from mercury exposure has increased rapidly in recent history, especially in oceans and other aquatic environments. In surface ocean water, mercury concentrations have, for example, increased two-fold over the last century, correlating with increases in industrialization and energy production.[707]

Mercury-based damage has been documented in a variety of species, spanning several water-based ecosystems across the United States. Generally, mercury damages wildlife by causing deformities in developing animals, lessening reproductive capacity, causing abnormal behavior that can hinder survival, rendering protective enzymes less effective, and even causing mortality.[708] Studies confirm, for example, that "mercury is adversely affecting diving ducks from the San Francisco Bay, herons and egrets from the Carson River in Nevada, and heron embryos from colonies along the Mississippi River."[709]

Mercury pollution in the Gulf of Maine is also known to affect populations of whales, porpoises, seals, and birds as well as some of the world's most productive fisheries.[710] In some cases, mercury concentrations in species of marine birds in the Gulf of Maine exceeded reproductive effect thresholds, preventing these species from sustaining healthy populations.[711]

Importantly, mercury's toxic dangers do not exist in isolation. Mercury's harm to species health can be amplified when combined with other contaminants, including those present in the wastestreams at many steam electric facilities, particularly coal-fired facilities. For example, methylmercury can be more harmful to bird embryos when selenium, another potentially toxic element, is present in the bird's diets.[712]

[707] Celia Y. Chen et al., Sources to Seafood: Mercury Pollution in the Marine Environment, 64 Me. Sea Grant Publ'ns (2012) (attached).
[708] EPA, EPA-452/R-97-005, Mercury Study Report to Congress, Vol. III: Fate and Transport of Mercury in the Environment (1997) (attached); Charles T. Driscoll et al., Mercury as a Global Pollutant: Sources, Pathways, and Effects, 47 Envtl. Sci. & Tech. (2013) (attached); U.S. Geological Survey, Fact Sheet FS-216-95, Mercury Contamination of Aquatic Ecosystems (1995) (attached); U.S. Geological Survey, Fact Sheet FS-016-03, Mercury in Stream Ecosystems – New Studies Initiated by the U.S. Geological Survey (2003) (attached).
[709] Id.
[710] Celia Y. Chen et al., Sources to Seafood: Mercury Pollution in the Marine Environment, 64 Me. Sea Grant Publ'ns (2012) (attached).
[711] Id.
[712] EPA, EPA-452/R-97-005, Mercury Study Report to Congress, Vol. III: Fate and Transport of Mercury in the Environment (1997) (attached); Driscoll et al., Mercury as a Global Pollutant: Sources, Pathways, and Effects, 47 Envtl. Sci. & Tech. (2013) (attached); U.S. Geological Survey, Mercury Contamination of Aquatic Ecosystems, Fact Sheet FS-216-95(1995); U.S. Geological Survey, Mercury in Stream Ecosystems – New Studies Initiated by the U.S. Geological Survey, Fact Sheet FS-016-03 (2003) (attached).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 187

Comment Excerpt:

3. Selenium

Selenium is a nonmetallic element that can produce toxic effects on animals in water-based ecosystems, as well as to humans. Like mercury and cadmium, selenium is bioaccumulative, making it a great source of concern for not only directly exposed species but also for organisms higher up on the food web.[713] Unlike mercury, however, some amount of selenium is essential for proper nutrition in living systems (approximately 0.04 to 0.1 parts per million for humans), though toxicity may occur if amounts in food are even slightly higher than that; for humans, toxicity may occur at amounts in food as low as four parts per million.[714]

Effects of selenium on fish and other water-based wildlife include: physical malformations during embryonic development; sterility; exophthalmos (popeye); pathological alterations in the kidney, liver, heart, and ovaries; anemia; cataracts; and death.[715] Selenium contamination can cause mutations in fish and other aquatic organisms,[716] and its bioaccumulative properties are known to cause very severe embryonic deformities and death in birds.[717] Selenium can also harm lower level organisms in water-based ecosystems, such as algae and plankton – organisms that are essential food sources for many aquatic species and without which can lead to starvation and death.[718]

[713] Steven J. Hamilton, Review of Selenium Toxicity in the Aquatic Food Chain, 326 Sci. of the Total Env't 1-31, at 1 (2004) (attached).
[714] U.S. Geologic Survey, Biological Res. Div. Info. & Tech. Rep. 1999–001, Field Manual of Wildlife Diseases, at 335-36 (1999) (attached); Patuxent Wildlife Research Ctr. & U.S. Fish & Wildlife Serv., Selenium Hazards To Fish, Wildlife, and Invertebrates: A Synoptic Review, at 6 (1985) (attached).
[715] U.S. Fish & Wildlife Service, Aquatic Cycling of Selenium: Implications for Fish and Wildlife, at 6-9 (1987) (attached); Dennis A. Lemly, Symptoms and Implications of Selenium Toxicity in Fish: The Belews Lake Case Example, 57 J. Aquatic Toxicology 1-2, at 39-49 (2002) (attached); U.S. Geologic Survey, Biological Res. Div. Info. & Tech. Rep. 1999–001, Field Manual of Wildlife Diseases at 335-36 (1999) (attached).
[716] Leslie Kaufman, Mutated Trout Raise New Concerns Near Mine Sites, N.Y. Times, Feb. 22, 2012 (attached).
[717] Patuxent Wildlife Research Ctr. & U.S. Fish & Wildlife Serv., Selenium Hazards To Fish, Wildlife, and Invertebrates: A Synoptic Review, at 6 (1985) (attached).
[718] Id.

28 EA – Halogens/Drinking Water Impacts

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 77

Comment Excerpt:

Bromides are dangerous because they can lead to the formation of trihalomethanes in drinking water supplies. Trihalomethanes can increase the risk of cancer, and can lead to liver, kidney, or central nervous system disease. Trihalomethanes are formed in the course of chlorination of drinking water when chlorine interacts with organic matter. The addition of bromide to source water can increase both the overall level of trihalomethanes and the prevalence of brominated species. Even a small increase in the amount of bromide in source water can increase the prevalence and concentrations of brominated trihalomethanes (bromoform, dibromochloromethane, and bromodichloromethane), thereby increasing the risk of harm, because organic disinfection byproduct precursors react preferentially with bromine over chlorine, generating higher concentrations of brominated trihalomethanes.[265] Of the four trihalomethane species regulated by EPA with a cumulative maximum contaminant level (MCL), two, bromoform and bromodichloromethane, have a MCL goal of zero, meaning no level of these trihalomethanes is safe for human health.[266]

[265] Jeanne M. VanBriesen, Ph.D., P.E., "Potential Drinking Water Effects of Bromide Discharges from Coal-fired Electric Power Plants," at 16-18 (Attachment 72).
[266] EPA National Drinking Water Regulations at 5 (May 2009), available at https://www.epa.gov/ground-water-anddrinking-water/national-primary-drinking-water-regulations (Attachment 73). EPA defines the Maximum Contaminant Level Goal as the "level of a contaminant in drinking water below which there is no known or expected risk to health."

Commenter Name: Michael P. Alaimo
Commenter Affiliation: Clean Fuels Michigan, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8305-A1
Comment Excerpt Number: 5

Comment Excerpt:

Bromide present in source water creates treatment challenges for drinking water systems because it reacts with the disinfectant chemicals used to kill harmful pathogens to form carcinogenic disinfectant byproducts. EPA's own record clearly documents the tremendous public health benefits of reducing bromide discharges from power plants, but its proposal lacks any requirement for plants to actually limit bromide discharges.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 9

Comment Excerpt:

First, EPA's estimates of health impacts from bromide do not support the inclusion of a bromide limit in the Proposed Rule, particularly for discharges to estuarine, marine, or tidally influence environments. In the Preamble, EPA suggests that changes in bladder cancer incidence from use and consumption of drinking water contaminated with TTHM are derived from bromides.[19] But although EPA mentions that there are several site-specific factors associated with the formation of TTHM, including chlorine, organic carbon, temperature, pH, and system residence time, it is unclear how EPA's analysis accounts for these additional factors that contribute to TTHM formation.[20] For example, one Group member evaluated TTHM data for its treatment plant and found that over 50% of the TTHM species identified were chlorine-based rather than bromine-based compounds. Nor are coal-fired stations the only source of bromides: in some circumstances elevated levels of TTHM may be attributed to inappropriately designed water treatment systems or systems operating below the original design basis where chlorinated water is retained for an extended period of time in storage tanks and distribution piping, which would facilitate formation of TTHM. EPA's use of only one potential factor associated with TTHM formation and one potential source for that factor in its quantification of benefits means that the benefit associated with addressing bromides in the ELG revision rule is likely overstated.

[19] Proposed Rule, 84 Fed. Reg. at 64,653-56.
[20] Id. at 64,656.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 85

Comment Excerpt:

Moreover, the proposed 'fix' of substituting chloramines for chlorine creates other problems for downstream drinking water users: chloramines are linked to health problems such as respiratory irritants, severe skin reactions, and greater exposure to pathogens in the water.[284] The City of Eden itself has recognized that certain sub-categories of people, such as people with kidney issues, will need to take special precautions when drinking chloramine-treated water.[285] Chloramines can also lead to the formation of carcinogenic byproducts called nitrosamines. Nitrosamine formation may be hastened by the presence of bromides.[286] Chloramines also cause other problems, including the leaching of lead from pipes. The switch from chlorine to chloramine has been implicated in elevated levels of lead observed in drinking water in Washington, DC and other cities. In these drinking-water distribution systems, the leaching of lead from pipes had been inhibited for many decades by a chlorine-induced coating of insoluble lead oxide on the surface of the pipes. After chlorine was replaced by chloramine, which is not as strong an oxidant, the coatings became more soluble and released higher concentrations of lead into the drinking water.[287] Lead leaching from chloramines should be a concern in many places, including, for example, some communities in South Carolina whose drinking water utilities switched to chloramines due to concerns about bromides from upstream FGD wastewater discharge. [288]

[284]Citizens Concerned About Chloramine, Chloramine Facts (Sept. 11, 2006), http://www.chloramine.org/chloraminefacts.htm (Attachment 94); see also World Health Organization, Seminar Pack for Drinking-Water Quality at 5, http://www.who.int/water sanitation health/dwq/S04.pdf (According to the World Health Organization, "monochloramine is about 2,000 and 100,000 times less effective than free chlorine for the inactivation of E. Coli and rotaviruses, respectively.") (Attachment 95).
[285] Eden 2015 Water Quality Report, Attachment 86.
[286] See Amisha Shah et al., Trade-Offs in Disinfection Byproduct Formation Associated with Precursor Preoxidation for Control of N-Nitrosodimethylamine Formation, 46 Environ. Sci. Technol. 4809, 4809 (2012) (Attachment 96).
[287] David L. Sedlak and Urs von Gunten, The Chlorine Dilemma, 311 Science Mag. 42, 43 (2011) (Attachment 97).

[288] Sammy Fretwell, Lead tainted water in SC communities, THE STATE (Feb. 19, 2016), available at http://www.thestate.com/news/local/article61283287.html (Attachment 98).

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 49

Comment Excerpt:

BROMIDE

7.1 **EPA's bromide mass loading and transport model appears to have overestimated the amount of bromide reaching downstream drinking water treatment systems from current coal-fired power plant discharges.**

EPA estimated mass loadings of bromide to surface water from flue gas desulfurization (FGD) wastewater and bottom ash transport water (BATW) [ERG, 2019a]. Downstream transport of bromide to the inlet of Public Water Supply (PWS) drinking water treatment systems was modeled using a set of transport equations, the D-FATE model. EPA used the modeled bromide concentrations in the PWS source water to estimate excess cancer risk from exposure to disinfection byproducts (DBPs) formed from the additional bromide. EPA used this analysis to determine that five power plants out of 70 evaluated could potentially have unacceptable downstream health impacts. EPRI reviewed the EPA methodology and determined that the bromide loadings and downstream impacts were apparently overestimated. EPRI recommends that EPA reevaluate its modeling results and the number of facilities impacted after addressing the sources of the overestimation.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 77

Comment Excerpt:

3. Absent Strict Standards to Control Bromide Discharges, Human Health Will Continue to Be at Risk and Drinking Water Systems Will Continue to Face Increasing Costs and Treatment Challenges

As documented in the record, described in the Proposed EA and Proposed BCA and discussed above, drinking water systems in different regions of the country are being impacted by coal plant bromide discharges. Even when drinking water systems are able to adjust treatment to ensure regulated DBPs do not exceed the MCL, different DBP treatment options come with their own human health risks and treatment challenges. Consequently, EPA should require upstream power plants to control their bromide discharges. As discussed in an earlier section of these comments, there is no "safe level" for some brominated DBPs, so any reduction of DBP concentrations below the MCL will benefit human health.

By failing to require bromide limits in FGD wastewater, EPA continues to shift the burden from coal plants polluting upstream onto downstream drinking water utilities and their customers. A more equitable approach to this problem would be to control this pollution at its source – in upstream bromide discharges – rather than forcing drinking water systems to invest in complicated treatment options that could continue to put public health at risk. By not requiring coal plants to limit their own bromide discharges, EPA is failing to meaningfully act on vital information available in its own rulemaking record. Moreover, the same treatment technologies that would more effectively address bromide pollution in FGD wastewater discharges – in particular: membrane technology or its equivalent – would also similarly eliminate other pollutants in the discharge stream, creating substantial additional public health benefits that the 2019 Proposal foregoes by not requiring the best-performing technologies as BAT.[274]

[274] See Section XIII - Benefits.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 84

Comment Excerpt:

b. Membrane filtration is necessary to eliminate bromide discharge and prevent the formation of trihalomethanes in downstream drinking water supplies.

It is essential for EPA to address bromide discharges by settling an effluent limitation for power plants, rather than leaving it up to drinking water utilities to treat the resulting trihalomethanes downstream. By failing to put a limit on bromide discharges, EPA shifts the burden of dealing with the downstream impacts of bromide pollution onto already-burdened drinking water utilities, which are often small, rural municipalities.

The experience in North Carolina and Virginia underscores the importance of setting membrane filtration as BAT for bromide. Even though Duke Energy poured millions of dollars into attempts to help find a band-aid solution for the Madison and Eden drinking water utilities, it was not able to eliminate the bromide-caused carcinogens in these drinking water systems. There is no guarantee that the so-called 'fixes' that Duke Energy pursued will eliminate these bromide-caused carcinogens from peoples' drinking water. In 2015, trihalomethane levels in the City of Eden's water supply were detected as high as 89 parts per billion,[279] and in 2016, they increased to as high as 100 ppb.[280] In 2017, trihalomethane levels were detected as high as 87 ppm,[281] and in 2018 (the most recent reporting year), they were as high as 86 ppm.[282]

The City of Danville, Virginia, which is on the North Carolina border on the Dan River, downstream of Belews Creek, also took action to address trihalomethanes that were formed as a result of bromide discharges from Belews Creek. In 2015, it reported installing new technology to reduce the formation of trihalomethanes, yet based on subsequent water quality reports, it does not seem to have been effective. In 2018 (the most recent reporting year), Danville suffered from total trihalomethane levels as high as 120 parts per billion, and in the third quarter of 2018, it violated the EPA MCL of 80 ppb with an average level of total trihalomethane of 85 ppb.[283]

[279] City of Eden, 2015 Annual Drinking Water Quality Report, 5, available at http://www.edennc.us/DocumentCenter/View/1226 (Attachment 86).
[280] City of Eden, 2016 Annual Drinking Water Quality Report, 5, available at https://www.edennc.us/DocumentCenter/View/5779/2016-Water-Quality-Report (Attachment 87).
[281] City of Eden, 2017 Annual Drinking Water Quality Report, 4, available at https://www.edennc.us/DocumentCenter/View/10316/2017-Water-Quality-Report-- (Attachment 88)
[282] City of Eden, 2018 Annual Drinking Water Quality Report, 5, available at https://www.edennc.us/DocumentCenter/View/11061/2018-Water-Quality-Report (Attachment 89).
283 City of Danville, 2018 Water Quality Report, 4, available at https://danvilleutilities.com/Attachments/2018%20Water%20Quality%20Report%20FINAL.pdf (Attachment 90); see also City of Danville 2015 Water Quality Report, PWSID # 5590100 at 2-3 (2015) (showing trihalomethane detections as high as 100 parts per billion) (Attachment 91); City of Danville 2016 Water Quality Report, available at https://danvilleutilities.com/Attachments/2016%20Water%20Quality%20Report.pdf (showing total trihalomethane detections as high as 108 ppb) (Attachment 92); City of Danville 2017 Water Quality Report, available at https://danvilleutilities.com/Attachments/2017%20Water%20Quality%20Report%20Final.pdf (showing trihalomethane detections as high as 91 ppb) (Attachment 93). The City of Danville installed a new mixing and aeration system at one of its storage reservoirs to help remove trihalomethanes, but subsequent water quality reports show high levels of total trihalomethanes are still detected in drinking water. Id

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 86

Comment Excerpt:

Belews Creek may be one of the best documented examples of bromide issues from FGD discharges in our region, but it is not the only one. For example, in Alabama, the City of Birmingham had to shut down its drinking water intake when trihalomethane levels reached 130 parts per billion, 50 parts per billion over the EPA standard.[289] In Virginia, quarterly sampling at a drinking water plant in Hopewell, VA, downstream of Dominion Energy's Chesterfield Power Station, indicates that, since at least 2011, total trihalomethanes levels have been elevated, and have regularly approached or exceeded the MCL, and brominated forms of trihalomethanes have been present at levels higher than would be expected without bromide addition to source water.[290] The FGD discharge at Chesterfield Power Station is likely a significant contributor to this chronic problem. There also have been problems at sites in North Carolina other than Belews Creek.[291]

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 87

Comment Excerpt:

In sum, an effluent limitation based on membrane filtration is sorely needed to control bromide. Although there is an outdated federal limit on total trihalomethanes in drinking water, there has been no federal limit for bromide in FGD wastewater, meaning the common source of the problem (power plants discharging bromides) is left unchecked. States, including North Carolina and Virginia, have no state limits on bromide. At Belews Creek, there were no numerical limits on bromide discharges in Duke Energy's wastewater permit. Duke Energy's permit for Belews Creek still contains no numerical limits for bromide—it is only required to periodically monitor it.[292] Likewise, Dominion Energy's permit for Chesterfield does not limit bromide discharge, nor does it require monitoring. Instead of placing the onus of dealing with the problems created by bromide on downstream drinking water systems, EPA must address the problem on the front end by requiring effluent limitations based on membrane filtration.

[292] NC DEQ, Final NPDES Permit Renewal, Permit NC0024406, Belews Creek Steam Station (March 21, 2019), available at https://files.nc.gov/ncdeq/Coal%20Ash/2019-actions/24406-Final-Permit-signed-2019.pdf (Attachment 101); see also letter from Southern Environmental Law Center to NC DEQ (July 30, 2018) (Attachment 102)

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 10

Comment Excerpt:

Likewise, a literature review conducted by the Electric Power Research Institute (EPRI) has critiqued articles linking bromide discharges from coal-fired power plants to exceedances of EPA's Stage 2 Disinfectants and Disinfection Byproducts Rule (DBR).[21] Issues identified with those articles include errors in calculations and conservative assumptions used to compensate for uncertainty in complex modeling, among others. These errors indicate that the current record does not adequately support the argument that FGD wastewater is the source of disinfection byproduct violations.

[21] EPRI, "Impacts of Bromide from Power Plants on Downstream Disinfection Byproduct Formation: A Literature Review," at ix (Nov. 2019), available at https://www.epri.com/#/pages/product/000000003002016479/?lang=en-US.

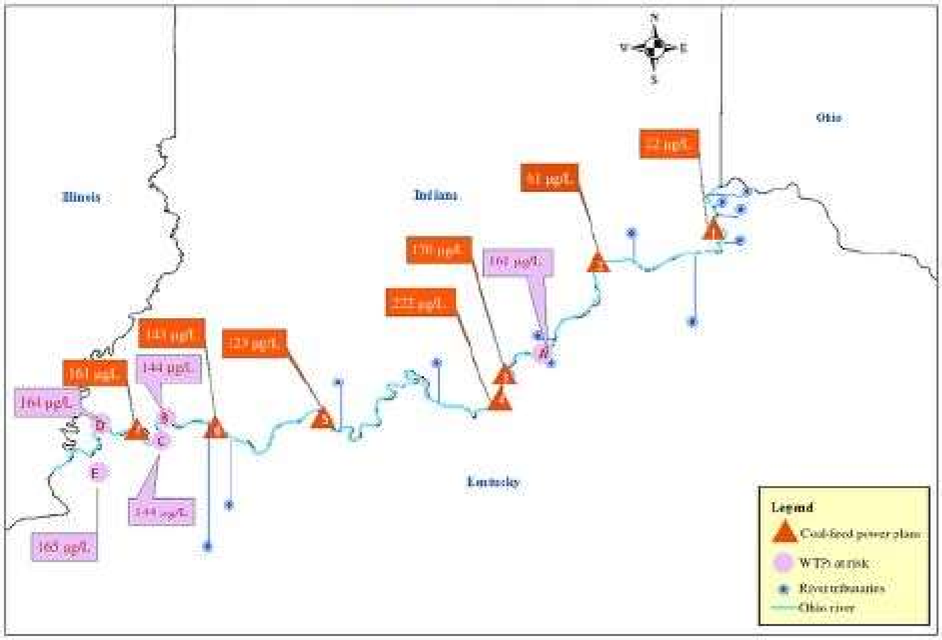
Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 77

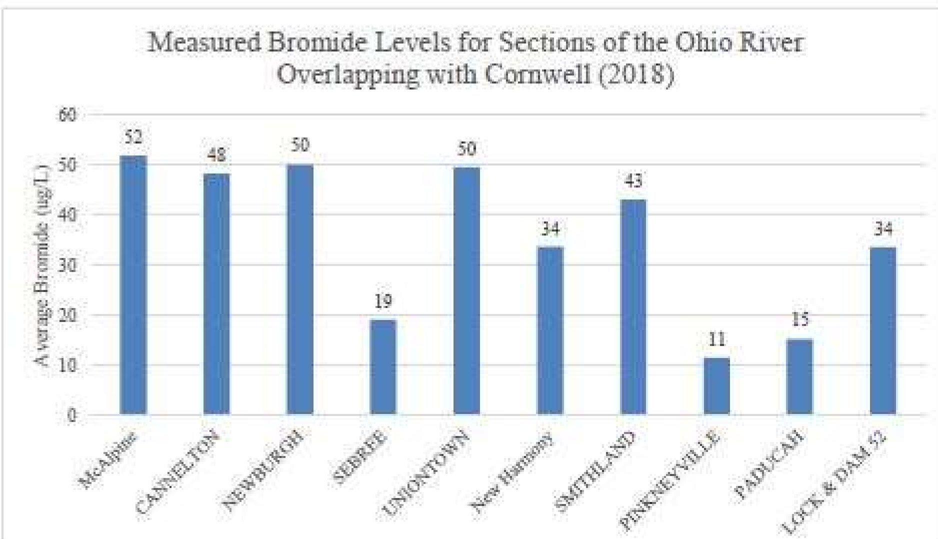
Comment Excerpt:

5. The Research Overestimates In-Stream Bromide Concentrations Due to Flaws in Hydrologic Modeling.

The research also takes a conservative approach to hydrology and hydraulics, likely overestimating potential bromide impacts. Seasonal variations in rainfall affect the quantity of flow in riverine systems, which has a significant impact on the concentration of bromide in the water. For example, the same discharge of bromide will produce lower concentrations during periods of higher flows and higher concentrations when there are lower flows. Cornwell (2018) used dynamic modeling to address flow variability but only focused on low flow periods, which likely occur only 20 percent of the time.[131] By calculating impacts during periods of low flow, the article exaggerates the likely impacts from bromide discharges the rest of the year. Furthermore, of the recently published articles that focused on impacts of bromide discharged from coal-fired power plants, none of them verify their calculations with sampling of instream data. For example, since 2013, the Ohio River Valley Water Sanitation Commission ("ORSANCO") has been collecting bromide samples from 29 locations along the Ohio River and its major tributaries. ORSANCO's publicly available data differ significantly from the data in Cornwell (2018) Figure 2, depicted below.[132]

Cornwell (2018) Figure 2 - Modeled Bromide Values





For example, for ORSANCO's first five monitoring locations, from McAlpine to Uniontown, average bromide levels vary from 19 to 52 µg/L. The corresponding section of the river in Cronwell (2018) is from drinking water treatment plant A to plant E. But Cornwell's modeled bromide values in this section range from 123 to 222 µg/L, significantly higher than the ORSANCO data.

The research has not identified (beyond a few isolated examples) drinking water facilities adversely impacted by bromide discharges. According to EPA's 2015 ELG Rule, one study "showed an increase in bromides at four drinking water utilities' intakes after wastewater from []

FGD systems began to be discharged to the rivers." However, the same study found increased levels of TTHM at only one facility. 80 Fed. Reg. at 67,840. Therefore, where it is necessary to bring drinking water treatment facilities into compliance with TTHM requirements, it may be more appropriate and cost-effective to modify the water treatment facility or the water treatment process itself, rather than set a national standard for bromide.

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[131] EPRI Bromide Report at 7-2.

[132] ORSANCO's monitoring locations overlap with the locations depicted in Cornwell (2018) Figure 2 but do not correspond directly. For example, the first five ORSANCO monitoring locations, from McAlpine to Uniontown, correspond to various locations between water treatment plants A through E on the Cornwell (2018) map. The remaining monitoring stations, from New Harmony to Paducah, are located further downstream along the Ohio River.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 78

Comment Excerpt:

6. The Number of Affected Populations is Overstated.

Additionally, one of the most frequently cited articles to identify affected populations significantly overestimates the potential risks to downstream water users.[133] In order to quantify potentially affected populations, the articles multiply the anticipated bromide concentration contributions from all upstream power plants by the potentially affected population of downstream drinking water users. First, as noted above, the number of relevant power plants and the quantity of bromide in the FGD wastewater discharges has been overstated. Second, bromide discharges were tracked up to hundreds of miles downstream, ignoring the uncertainty associated with the hydrologic complexity of riverine systems that considerably affects the degree of dilution. Third, water treatment facilities generally withdraw water from multiple sources, and therefore it's unclear what percentage of the population is served by the surface water of interest, rather than other streams, lakes, or groundwater. As such, there is significantly more uncertainty in calculating the affected population than the Good and VanBriesen (2019) article suggests.

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[133] See Good and VanBriesen (2019).

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 4

Comment Excerpt:

In addition, non-coal sources of iodine include pharmaceuticals and FDA required levels in table salt. Pharmaceuticals (including disinfectants) and contrast agents are estimated to represent more than half of the increases in iodine levels in water.

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 5

Comment Excerpt:

Requirements in the Steam Electric ELG to reduce iodine levels to below naturally occurring levels inappropriately transfers public water plant treatment responsibilities to the power-generation sector. At this time, insufficient data and analysis is available to determine the impact of coal-burning power plants or any other single source on iodine levels in source water for public water treatment plants.

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 7

Comment Excerpt:

Any potential impact of iodine or other halogens to downstream water treatment is dependent on multiple factors, including: the amount of iodine or halogen in the water from natural or nonpower-plant sources, the amount of iodine or halogen discharged by the power plant; the volume of flow of the water into which such halogen is discharged; and the distance from the point of discharge to the water treatment facility. A variation in any aspect of the above could fundamentally change the potential for formation of DBPs.

Significant additional research would be required in order to determine a regulatory approach to discharge of iodine. Given the variabilities due to downstream effects, it appears any such regulatory approach should be determined at the local rather than national level, where the specifics of other contributors, water flow, and distance could be appropriately taken into account.

Commenter Name: Ron Eller and Jim Zerefos
Commenter Affiliation: Tinuum Group, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8306-A1
Comment Excerpt Number: 6

Comment Excerpt:

The EPA's Steam Electric ELG proposal related to the potential regulation of bromine is premised upon the potential for application of bromine to facilitate formation of disinfection byproducts (DBPs) downstream. To state the obvious, iodine is not bromine and the interaction of each halogen must be reviewed and assessed independently. DBPs are formed as a result of disinfectants at water treatment plants reacting with halogens in the incoming water. Disinfectants used at water treatment plants with higher oxidizing strength, such as chlorine dioxide, and high relative doses of chlorine to iodide will convert most iodine to iodate, which is a non-toxic sink for iodide in treated water.

Most research to date on DBP formation has focused on chlorine or bromine, with significantly less research on iodine. What limited research has been conducted on DBP formation specifically related to iodine is limited in geographic scope and data and fails to support a conclusion with respect to the potential national impact of iodine. Regardless of the regulatory approach to bromine in the Steam Electric ELG, it is neither appropriate nor scientifically justified to include iodine or other halogens without discrete review of the impact of each halogen. Significant additional research on iodine and potential DBP formation would be required prior to an assessment of the appropriateness of any regulatory restrictions.

29 EA – IRW Model

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 202

Comment Excerpt:

C. EPA Did Not Address the Disproportionate Impacts on Children of Consuming Contaminated Fish.

EPA evaluated the non-cancer and cancer human health impacts from consuming fish from contaminated wastewaters in the Proposed EA and found that all of its proposed options increase the number of receiving waters contributing to oral RfD (non-cancer) exceedances over the baseline.[779] Although EPA's results show disproportionate impacts on children, EPA makes no mention of these results in the proposed rule, and does not take them into consideration when weighing the various options. Table 4-7 of the Proposed EA compares how each of the four options increases the number of receiving waters contributing to oral RfD exceedances.[780] The table shows that the impacts of Option 2 on children are disproportionately greater than on adults (e.g., for selenium subsistence, there is a 2.25 times greater impact on children (9/4), and for mercury subsistence, there is a 1.4 times greater impact on children (17/12). Additionally the table shows that the increased impact of Option 2 versus Option 4 is disproportionately more harmful to children (e.g., for subsistence child 1.7 (19/11) times greater for any pollutant under Option 2 versus under Option 4, versus only 1.5 times greater (12/9) for subsistence adults for any pollutant under Option 2 versus Option 4).[781]

[779] Proposed EA at 4-11.
[780] Id. at 4-12, Tbl. 4-7.
[781] Id.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 203

Comment Excerpt:

D. EPA Does Not Account for Cumulative Impacts of Multiple Pollutants on Children.

EPA's assessment of the potential impacts to children is narrowly focused on a few impacts of individual pollutants. EPA did not assess the cumulative impacts of the pollutants that have disproportionate impacts on children. For example, EPA notes that it did not consider the impact of mercury on the uptake or toxicity of selenium. "There is evidence in the literature (Chapman et al., 2009) that these two compounds interact in the environment to decrease each other's impact on a receptor. Conversely, the interaction of other pollutants may increase the impact to a receptor."[782]

[782] Id. at D-8.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 35

Comment Excerpt:

On page 6 of the rulemaking record document "Receiving Water Characteristics Analysis and Supporting Documentation for the 2019 Steam Electric Supplemental Assessment," DCN SE07925, ERG October 31, 2019, ERG details the receiving water information assumed for

CWLP's discharge. In footnote "a" to the table, it appears the consultant discovered that they had incorrectly linked the discharge point to Lake Springfield rather than Sugar Creek. While this conclusion is accurate for bottom ash transport water for which CWLP is a ***direct*** discharger to Sugar Creek under an NPDES permit, even this correction does not properly identify CWLP's indirect discharge which following treatment at the SCRWD's Spring Creek facility is discharged to the Sangamon River from Outfall 007 (Latitude: 39° 51' 3 7.234" North, Longitude: 89 38' 30.082" West).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 138

Comment Excerpt:

Second, UWAG is concerned that EPA's 2015 assessment of the environmental impacts of power plant discharges prior to the 2015 ELG rule, in tandem with its 2019 assessment of the extent to which the current proposal would decrease or increase those impacts, is presented in a fashion that might give rise to misinterpretation. EPA, *Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* EPA-821-R-15-006, EPA-HQ-OW2009-0819-6427 (Sept. 2015) ("2015 EA"); Supplemental EA at 3-3, *citing* 2015 EA. Although the 2015 EA and the Supplemental EA both indicate that EPA calculated "plant-specific" baseline and postcompliance pollutant loadings, the 2015 TDD and the Supplemental TDD on which those loadings are based make clear that EPA did not use site- and pollutants specific discharge data from all affected facilities. See Supplemental EA at 3-3 (referring to the Supplemental TDD description of how EPA calculated estimates of baseline and post-compliance loadings); 2015 EA at 3-13 (referring to Section 10 of the 2015 TDD). Instead, those estimates are based on a combination of plant-specific flows (in some cases, estimated rather than actual flows, where EPA deemed flow data inadequate) and average pollutant levels from a handful of plants that EPA deemed representative of discharges from other facilities. These values were then applied, through an "instream receiving water" model that made further assumption about the nature and behavior of the receiving water. UWAG encourages EPA to acknowledge more clearly than it has that these estimates are, at best, rough approximations of the potential impacts from the affected facilities.

30 <u>EA – Downstream Analysis</u>

No comment excerpts were received on this topic.

31 EA – Proximity Analyses

No comment excerpts were received on this topic.

32 EA – Environmental Change Under Regulatory Options

No comment excerpts were received on this topic.

33 Regulatory Implementation – Timing

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 2

Comment Excerpt:

EPA should expedite the process of finalizing the proposal so that permitting authorities and regulated facilities can begin the process of renewing or modifying permits and initiate projects required for compliance.

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 14

Comment Excerpt:

V. EPA should continue to grant flexibility to permitting authorities to determine a date that is "as soon as possible" within the implementation period up to, and including, the final compliance deadline of December 31, 2023.

EPA solicits comments on whether the earliest date on which facilities may have to meet the proposed limitations should be later than November 1, 2020.[7] Due to the complexities of recent proposed changes to the ELG rule and other environmental regulations, the limitations created by short construction seasons, and the administrative burden placed on permitting authorities to reopen and modify existing permits, Berkshire Hathaway Energy recommends that EPA eliminate the compliance window altogether and impose a "no later than" universal compliance deadline of December 31, 2023. Implementing a "no later than" compliance date of December 31, 2023, would allow facilities time to adequately evaluate options under the proposed ELGs once it becomes finalized. In many cases, plants affected by the ELG rule are nearing end-of-life, and strategies that may be considered cost effective by EPA are not viable. With anticipated finalization of this proposal occurring in spring or summer of 2020, that leaves very little time for planning and evaluation.

7 Id. at 64,641.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 15

Comment Excerpt:

Finally, EPA should allow permit writers to extend the applicability dates for BATW compliance beyond December 31, 2023. Id. at 64,622. While the Proposed ELG Rule notes that many facilities have already begun making BATW retrofits and asserts that retrofits can be achieved in 15-23 months, retrofitting and installation of the required technology may, under certain circumstances require additional time—especially for companies that relied on the ELG postponement rule and those affected by the August 2018 decision from the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) regarding "lined" ponds who did not necessarily have the same starting point as other companies. [16]

[16] Some facilities have clay-lined ponds that met the criteria of "lined" ponds under the 2015 CCR Rule, and therefore were not subject to closure. 40 C.F.R. § 257.71(a)(1)(i). However, in August 2018 the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated this provision. Utility Solid Waste Activities Group v. EPA, 901 F. 3d 414 (D.C. Cir. 2018). EPA is planning to propose a rule that would "provide a mechanism in which unlined surface impoundments meeting strict criteria would be allowed to continue to operate." However, units that were not subject to the CCR Rule originally and became subject to it following the D.C. Circuit's decision did not have the same time and planning horizon as units and facilities that could incorporate compliance with both rules from the beginning.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 21

Comment Excerpt:

B. EPA's Provision of Additional Compliance Time is Appropriate, and The Agency Should Consider Extending the Compliance Timeframe.

EPA also proposes to update the compliance timeframe for the revised BAT FGD wastewater requirements to no sooner than November 1, 2020 but no later than December 31, 2025, as determined by the permit writer. Facilities opting to utilize the VIP program would have to comply by December 31, 2028. 84 Fed. Reg. 64,642. The proposed extension of the compliance timeframe for the new FGD wastewater requirements is appropriate and will provide EEI members with the additional time necessary to design, procure, engineer, test, pilot and install the technology that will be necessary to meet the new standards. Once installed, EEI's members will need some additional time to commission and optimize the technology in order to ensure that it can consistently allow for units to meet the applicable limits.

The additional time provided to meet the new FGD wastewater BAT requirements is necessary to allow for the various processes that must be undertaken to install the required technology. For example, substantial engineering work may be necessary to ensure that biological systems perform properly. Further, installing environmental controls and the long time horizons for project construction and implementation can require members to schedule unit outages over several months in order to ensure the projects can be completed in a timely manner and in a way that allows the units to continue to operate in a manner consistent with overall system needs, as discussed supra. At times, these scheduled outages can be difficult to balance as multiple, similarly situated and geographically adjacent units may all require the installation of control technology in roughly similar time horizons, requiring increased coordination amongst units, companies, and grid operators. As a result of these needed processes, the additional time provided to install and operate the new FGD wastewater BAT requirements are justified.

As EPA notes, when considering the technological availability and economic achievability of BAT limitations, it is appropriate to consider "the magnitude and complexity of process changes and new equipment installations…required at facilities to meet the proposed requirements," as well as the need to "raise capital, plan and design systems, procure equipment, and then construct and test systems…[and] also allow for consideration of facility changes being made in response to other Agency rules affecting the steam electric power generating industry (e.g., the CCR rule)." 84 Fed. Reg. at 64,641. The proposed applicability dates reflect a reasonable consideration of these factors.

Commenter Name: American Coal Council (ACC)
Commenter Affiliation: American Coal Council (ACC)
Document Control Number: EPA-HQ-OW-2009-0819-8315-A1
Comment Excerpt Number: 5

Comment Excerpt:

Compliance Deadlines

EPA's proposal extends the compliance deadline for the new rule to on or after November 1, 2020 but no later than December 31, 2023 for BATW and December 31, 2025 for FGD wastewater. We suggest that for the sake of consistency and with necessary considerations of compliance with both BATW and FGD wastewater as well as the CCR Rule, the deadline for compliance for BATW should be set as December 31, 2025.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 1

Comment Excerpt:

1. EPA should finalize the 2019 proposal to update the 2015 ELG Rule (2015 Rule) in a timely manner.

EPA's review of public comments and the potential changes to the ELGs that result from them should could occur expeditiously. This would allow for the industry to adequately plan, design and engineer the technology-based requirements presented in the final rule. Completing the final rule in a timely manner will also allow companies to work with their respective state regulatory agencies to modify and issue NPDES permits as early as possible to establish compliance deadlines within the appropriate applicability dates identified by the final rule.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 7

Comment Excerpt:

3. The applicability date for BATW should be extended to December 31, 2025.

EPA proposes to set the applicability dates for BATW to December 31, 2020 to December 31, 2023. They based this decision on information from technology vendors as well as from some industry facilities and they concluded that facilities may be able to complete design, procurement, installation, and operation of BATW technologies by December 31, 2023[7]. A. The proposed timeframe does not allow sufficient time for all required steps for such a project. The proposed applicability date does not allow the timeframe needed to implement a cost-effective project, nor is it sufficient to accommodate a full range of facilities affected by the BATW ELG. For example, EPA and its consultant conducted a request for quotation (RFQs) from vendors for a specific BATW technology. The responses to the RFQ averaged a timeframe of 35 months[8], but did not include key project steps such as procuring capital, obtaining permits or engineering retrofits for site specific applicability. EPA did consider these project steps in the 2015 Rule, but they failed to do so in the 2019 proposal because it "understands that some facilities may have already installed, or are now installing, technologies that could comply with the proposed limits”[9].

[7] Fed. Reg. Vol 84, p. 64641
[8] Fed. Reg. Vol 84, p. 64641
[9] Fed. Reg. Vol 84, p. 64641

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 8

Comment Excerpt:

i. CCR Rule requirements have not driven BATW ELG projects at all facilities.

In the preamble of the 2019 proposed rule, EPA states that extending the applicability dates for “facilities to comply with BAT limitations for BATW beyond 2023 is not necessary because of the process changes should already have occurred due to CCR rule requirements.[10]” Although this may be true for some facilities, but there are other facilities that were CCR compliant without having to install BATW technologies. For example, some facilities that utilize retention ponds or impoundments, which are CCR compliant, are able to adequately attain current ELG based TSS and oil/grease standards. Additionally, some facilities have clay-lined ponds that were not subject to closure under the CCR Rule, but in August 2018 the D.C. Circuit Court of Appeals vacated this provision[11]. EPA is planning to propose a rule[12] which would establish a mechanism to demonstrate clay-lined surface impoundments meet CCR criteria and be allowed to continue operation. Therefore, some facilities with clay-lined ponds are awaiting this rule and have not retrofitted BATW handling systems. In the 2019 proposal, EPA gives no consideration of the DC Circuit Court of Appeals decision and the impact it had on the industry when determining the BATW applicability timeframes.

[10] Fed. Reg. Vol 84, p. 64641
[11] Utility Solid Waste Activities Group v. EPA
[12] EPA Fall 2019 Unified Regulatory Agenda

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 9

Comment Excerpt:

B. The proposed applicability dates do not consider multi-unit facilities, unit outage impacts and potential skilled labor and supply shortages.

The 2019 proposal does not address factors that could be critical to a project and have implications to the overall timeframe of ELG based compliance projects.

i. Multi-Unit Generating Facilities

The impact of the December 31, 2023 applicability date is more critical for facilities with multiple units that would need to be retrofitted. As discussed previously, in the 2019 proposal EPA and its consultant appear to have failed to consider critical steps of a ELG compliance project that could take months or years to accomplish (i.e. permitting). The 2019 proposal did not indicate that EPA considered facilities with multiple units. Design and engineering for facilities with multiple units is more difficult and time consuming to ensure all project components are addressed and working as one system. Additionally, a multi-unit project adds significantly more time to a project as the compliance technology needs to be installed multiple times.

ii. Unit Outage Schedules

Depending on the type of BATW technology, significant unit outages may be required to “tie-in” the equipment to the existing infrastructure. If a significant outage is required, this could have implications on grid reliability and electrical demand. It is important for companies to strategically schedule their unit outages to avoid such issues and will often plan to execute multiple capital projects during a unit outage. This prevents the facility from requiring a forced outage and risking grid reliability and demand. In addition, unit outages at a multi-unit facility cannot be scheduled to occur at the same time in order to maintain adequate capacity to support electricity demand. The applicability date of December 31, 2023 in the 2019 proposal presents the risk that the date will impact the unit outage schedules for multi-unit facilities, possibly forcing unit outages and impacts to grid reliability and demand.

iii. Equipment and Labor Shortages

The 2019 proposal does not indicate that EPA considered potential difficulties in attaining equipment and labor procurement when establishing their BATW applicability date. Many of the ELG compliant technologies cannot be purchased “as is” and could take significant time to build once the design has been established. Competition for scarce resources such as long lead-time equipment, skilled labor and consultation services once the rule is finalized will likely create backlogs and delays in project timelines.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 10

Comment Excerpt:

C. FGD WW and BATW applicability dates need to match.

EPA should extend the applicability date in the 2019 proposal for BATW to December 31, 2025 to match the applicability date for FGD WW. This is necessary to accommodate the use of BATW as FGD absorber make up water. The 2015 Rule and 2019 proposal both allow for the discharge of BATW to a facility's FGD absorber to be used as scrubber water if it is treated by the FGD WW treatment systems and meets new FGD WW standards accordingly. However, due to the discrepancy of applicability dates for FGD WW and BATW in the 2019 proposal, technologies and associated treatments systems for FGD WW compliance may not be completed for up to two years after BATW technologies have been installed. This will prevent the discharge of BATW to the FGD absorber for up to two years. To allow facilities the time needed to design and implement a system that allows a discharge of BATW to the FGD absorber and then achieve compliance with the FGD WW ELG standards, EPA must extend the applicability date for BATW to December 31, 2025.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 11

Comment Excerpt:

D. The 2017 ELG Postponement Rule[13] Preamble

The 2017 Postponement Rule preamble summary states, "EPA's action to postpone certain compliance dates in the 2015 Rule is intended to preserve the status quo for FGD wastewater and bottom ash transport water until EPA completes its next rulemaking concerning those wastestreams." EPA then went on to say in the Background section of the Rule's Supplementary Information, "EPA explained that this postponement would preserve the regulatory status quo with respect to wastestreams subject to the 2015 Rule's new, and more stringent, limitations and standards during reconsideration and that postponement of compliance dates is intended to prevent the unnecessary expenditure of resources until EPA finalizes any rulemaking as a result of its reconsideration of the 2015 Rule." As a result of the Postponement Rule and the preamble language presented above, many companies subsequently paused their ELG compliance-based projects that were initiated in response to the 2015 Rule. EPA clearly stated that companies should not incur "unnecessary expenditure of resources" until the ELGs were reconsidered. Therefore, the lack of extension for the BATW applicability dates in the 2019 proposal put companies who followed the directive of the EPA in the 2017 Postponement Rule preamble to a disadvantage. These companies kept their expenditure of resources to a minimum following EPA's directive. Companies continued to evaluate potential compliant technologies but did not move forward with final engineering and design necessary to implement projects until final standards would be established by EPA in the new ELG Rule. This is especially true for companies who did not need to implement projects for CCR compliance (See item 3(A)(i) above). Since EPA gave the directive to not expend resources until their reconsideration of the 2015 Rule was complete, then by principle, the BATW applicability dates should be extended the same amount of time as EPA's reconsideration.

[13] EPA–HQ–OW–2009–0819; FRL–9967–90–OW; Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; https://www.federalregister.gov/documents/2017/09/18/2017-19821/postponement-ofcertain-compliance-dates-for-the-effluent-limitations-guidelines-and-standards-for

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 12

Comment Excerpt:

V. COMPLIANCE DATE MUST BE EXTENDED IN ORDER TO PROVIDE SUFFICIENT TIME FOR INSTALLING FGD WASTEWATER TREATMENT SYSTEMS.

Santee Cooper supports EPA's proposal to extend the compliance dates for facilities that will be building new treatment units for FGD wastewater. Based on our information, including discussions with vendors, we believe that a schedule on the order of five years from the date of publication of the final rule is reasonable but aggressive. It includes the benefit of a great deal of work Santee Cooper had invested toward complying with the 2015 rule. It does not account for difficulties and delays as the industry collectively pivots to the new treatment technologies, stretching the resources of vendors, suppliers, consultants, and skilled labor in meeting an aggressive schedule. Construction costs could be lowered with a longer time frame, and we support UWAG's request for a longer timeframe.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 13

Comment Excerpt:

F. Compliance with the Proposed ELG Revision Rule Will Require Timely Finalization of the CCR, ELG Revision Rules CCIG agrees with EPA that the CCR Rule Amendments,[25] if finalized as proposed, will have implications for the requirements found in the Proposed Rule, and agrees that the overlap is an important consideration for EPA as it finalizes both sets of rulemakings.[26] Specifically, (1) compliance with the revised ELGs will require timely finalization by EPA of both the CCR and the ELG proposed revisions and (2) EPA should consider extending the deadlines for ELG compliance to account for the time it will take companies to make changes responding to the CCR Rule Amendments. First, should the CCR Rule Amendments and/or the Proposed Rule fail to be finalized in a timely manner, plants may have difficulty submitting requests for extensions to operate certain unlined ponds under the proposed CCR Rule Amendments because they will not fully know their compliance obligations.

As proposed, the CCR Rule Amendments establish deadlines as early as May 15, 2020 to seek such extensions; without knowing very soon the full scope of the regulatory obligations companies will be subject to under both the CCR Rule and the ELG program, companies may not know by that date whether they will require an extension. Second, the current timelines proposed by EPA leave very little room for operators to understand their new compliance obligations and how those new obligations under the CCR Rule and the ELG program interact with each other. Adjusting the compliance timeline under the Proposed Rule - especially the timeline for BATW – to account for adjustments that may be necessary in light of the CCR Rule Amendments would help alleviate these concerns. As proposed, the CCR Rule Amendments establish an initial presumptive compliance deadline of August 31, 2020, by which all unlined surface impoundments must cease receiving waste, leaving a window of a few months at most for many facilities to take all appropriate actions to be in compliance with the new CCR Rule requirements.[27] The proposed compliance deadlines in the ELG Proposed Rule, especially the BATW compliance deadlines, follow shortly after the CCR rule deadlines: EPA generally proposes that the limitations apply as soon as possible on or after November 1, 2020, but no later than December 31, 2023 for BATW or December 31, 2025 for FGD wastewater.[28] These timelines leave very little room for operators to make adjustments that may be required in light of CCR rule requirements. Therefore, CCIG respectfully requests that EPA consider adjusting the compliance timelines found in the Proposed Rule – especially the timeline for BATW – to account for adjustments that may be necessary in light of the CCR Rule Amendments.

[25] 84 Fed. Reg. 65,941.
[26] See, e.g., Id. at 64,626, 64,664 ("The limit of what is practicable at a facility may change drastically after making changes to comply with the CCR rule. For instance, if a facility closes its unlined surface impoundment and installs a remote MDS, the recycle rate that is practicable may approach that of the high recycle systems that the EPA used to establish BAT for units not falling into this subcategory.").
[27] CCR Rule Amendments, 84 Fed. Reg. at 65,942, 65,948.
[28] Proposed Rule, 84 Fed. Reg. at 64,622.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 2

Comment Excerpt:

BATW Applicability Date

First, the Proposed ELG Rule maintains that systems retrofitting to high recycle rate processes can do so by December 31, 2023. USEPA supports the Proposed date by stating, "Information in the record indicates that most facilities should be able to complete all steps to implement changes needed to comply with Proposed BA transport water requirements within 15–23 months…" 84 Fed. Reg. at 64,665. Contradicting the previous statement, the docket contains information from 35 retrofits that displays that remote mechanical drag systems ("rMDS") have an average Initial Request for Quotation ("RfQ") to Operational time period of 32 months. See EPA-HQ-OW-2009-0819-8191, page 3, Table 2. Furthermore, the times presented are all averages and do not present a full picture of what some facilities across the Country face and therefore is not necessarily applicable nationwide. Finally, the information in the record is from vendors and does not include pertinent information that the vendor would not have access to. Such information includes, but is not limited to, permitting, financing mechanisms, public utility commission approvals, lack of labor professionals, and site-specific issues, such as access limitations, logistics limitations, and outage sequencing. In FirstEnergy's previous experience, we have seen significant delays caused by permitting agencies or other regulatory bodies.

FirstEnergy is particularly concerned with the lack of consideration given for outage sequencing in the Proposed ELG Rule. When projects do not correspond to normal, regularly planned facility outages, they can present a variety of issues to the facility and the larger electric grid, including the consumer. Projects that fall outside of the normal outage cycle may force the unit to come down during periods of elevated demand. Normal, planned unit outages only occur in the spring and fall due to higher demand in summer and winter and only occur once every three years, upon request and *approval* [emphasis added] through the Regional Transmission Organization ("RTO"). Aggressive applicability dates for BATW could require an outage during elevated demand periods which results in higher electric prices or grid resiliency issues during these periods. In addition, submerged grind conveyors, require work directly on the boiler, particularly the clinker grinders and/or jet pumps. Whenever work is performed directly on the boiler, outages become longer and more complex.

The Proposed ELG Rule also never factored in outage sequencing for multiple unit plants. At multiple unit plants, site specific challenges can occur, particularly when more than one unit has an outage at the same time. These challenges can include, but are not limited to, resource (labor and material) limitations, site constraints, equipment laydown and setup constraints. As mentioned above, the RTO must approve outages and when multiple units are affected grid reliability and resiliency become a greater concern. For instance, FirstEnergy's Harrison Power Station ("Harrison") is a three-unit, 1,984-megawatt ("MW") plant in Haywood, West Virginia. Harrison has one-unit outage scheduled per year. Assuming the Proposed Rule's final requirements will not be finalized until mid-2020, the facility will have to perform detailed design, RfQ, permitting, finance planning and securing, procurement, and take delivery of all equipment in less than 12 months to meet the 2021 outage. If the 2021 outage is not met, the next outage is not until 2024 (after the latest applicability date for BATW).

The Proposed ELG Rule notes that over 75 percent of the industry has now installed dry or high recycle rate BATW systems. See 84 Fed. Reg. at 64,634. However, this still leaves 25 percent and several FirstEnergy units needing to retrofit existing systems. There are only two generally accepted vendors that understand and install BATW retrofit systems to meet the needs of most, if not all, of these remaining facilities. In addition, the fast approaching applicability dates will force all the remaining facilities to place their orders with the two vendors at approximately the same time.

While EPA looks at national applicability of a technology, the Proposed ELG Rule did not consider labor availability to meet the proposed applicability date. The United States is in one of the largest economic expansions in history. Compounding this expansion, several FirstEnergy states are undergoing an economic stimulus from the Marcellus and Utica Shale natural gas formations. Not only does the extraction of natural gas require labor but several downstream industries also require skilled labor. In one such instance, an ethylene cracker plant is under construction in the middle of FirstEnergy's territory. The plant is requiring almost 6,000 construction workers, at its peak, and $6 billion in investment. At least two additional, similar ethylene cracker plants are under consideration in the area. The tight labor market coupled with large natural gas related projects are creating a strain in obtaining the requisite talent and completing projects in a timely fashion. This same workload not only affects labor talent but also local engineering talent for supporting system design and procurement.

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 11

Comment Excerpt:

FGDW Applicability Date
FirstEnergy generally supports EPA's FGDW applicability date as written in the Proposed ELG Rule. However, FirstEnergy believes consideration should be given to allow for justified extensions to be granted by the permitting authority on the FGDW applicability dates. While EPA's analysis shows that 114 or so systems will be affected in the Regulatory Impact Analysis, the burden falls mostly in the eastern United States eliminating large majorities of the Country. See EPA-HQ-OW-2009-0819-7106, Page 2-2, Table 2-1. In fact, EPA's on Regulatory Impact Analysis shows 86 percent of the compliance costs will be concentrated in only two NERC regions, Reliability First Corporation and SERC Reliability Corporation, which comprises less than half of the United States. See EPA-HQ-OW-2009-0819-7106, Page 7-3, Table 7-1. The concentration of units requiring the retrofits may cause regional procurement and construction difficulties. With the current state of the coal electric utility industry, the decision to complete multi-million-dollar upgrades to a plant has become a very complicated process. Items such as loss of company jobs, supporting industry jobs, future politics, future of gas prices, are just some of the multitude of factors that must be considered. Also, this decision is further complicated with the addition of the Coal Combustion Residuals and Affordable Clean Energy rules. Therefore, FirstEnergy believes that with justified information the permitting agency should have the authority to grant extensions (up to a maximum of 2 years) as appropriate.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 1

Comment Excerpt:

As a first priority, UWAG urges EPA to finalize this rule as soon as reasonably possible, consistent with all necessary administrative procedures. Facilities subject to the 2015 rule have been waiting since April 2017, when EPA granted the reconsideration, for further direction on the two waste streams being reconsidered. Some of these facilities have received permits with applicability dates that are fast approaching. Other facilities expect to initiate permit renewal activities soon. And the majority of facilities subject to the ELG rule are also subject to the Coal Combustion Residuals ("CCR") rule, which is undergoing its own process of amendment. The certainty of a final ELG rule would be beneficial because it would answer some questions regarding how the facilities will operate in the future and thus will allow owners and operators to plan appropriately.

Commenter Name: Mike Krumland
Commenter Affiliation: Nebraska Public Power District (NPPD)
Document Control Number: EPA-HQ-OW-2009-0819-8308-A1
Comment Excerpt Number: 1

Comment Excerpt:

In the 2015 Rule, the earliest compliance date for new, more stringent BAT effluent limitations and PSES for FGD wastewater and BA transport water was no later than November 1, 2018. In the 2017 Postponement Rule, EPA amended the date to no later than November 1, 2020. In this Proposed Rule, EPA is suggesting that the earliest compliance date for BA transport water will remain no later than November 1, 2020.To ensure compliance and for consistency with the CCR Rule, EPA should set the deadline for compliance with BAT limitations for BA transport water as no later than December 31, 2025.

Unlike the 2015 ELG rule however, the Proposed Rule's applicability dates for BA transport water and FGD wastewater are no longer in harmony. Instead, the latest BA transport water deadline is two years shorter than the latest FGD wastewater deadline. NPPD would like the compliance harmonized to ensure good decisions are made regarding BA transport water. We encourage the EPA to establish a BA transport water applicability date of no later than December 31, 2025.

Commenter Name: John P. Shimshock
Commenter Affiliation: Keystone-Conemaugh Projects, LLC (KEY-CON)
Document Control Number: EPA-HQ-OW-2009-0819-8304-A1
Comment Excerpt Number: 1

Comment Excerpt:

KEY-CON is concerned that the proposed "no later than" date may not be sufficient to ensure that the required evaluation studies are planned, developed, funded and completed, and wastewater treatment systems or system modifications are designed, engineered, manufactured, permitted, constructed and optimized by the compliance deadline. Furthermore, assessing the complexity and implications for power plants that will convert existing once-thru Bottom Ash Transport Water (BATW) systems to zero or near zero discharge, which could include rerouting BATW to the FGD as an alternative source of make-up water and incorporating into treatment system design as well as possibly redirecting other stormwater and low volume wastes to maintain a viable water balance and meet BATW BAT additionally, supports our proposed "no later than" compliance date concern. Consequently, KEY-CON is requesting EPA to include a provision in the final rule that would allow sources to seek up to three sequential one-year extensions as needed beyond December 31, 2025 compliance date for FGD wastewater and December 31, 2023 for BATW. A compliance time schedule that is in accordance with this request would be consistent with the compliance schedule included in the 2015 rule. EPA noted the following in that rule:

As part of the consideration of the technological availability and economic achievability of the BAT limitations in the rule, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the rule's requirements. As described in greater detail in Section XVI.A.1, where BAT limitations in this rule are more stringent than previously established BPT limitations, those limitations do not apply until a date determined by the permitting authority that is as soon as possible beginning November 1, 2018 (approximately three years following promulgation of this rule), but that is also no later than December 31, 2023 (approximately eight years following promulgation).

Consistent with the proposal and supported by many commenters, the final rule takes this approach in order to provide the time that many facilities need to raise capital, plan and design systems, procure equipment, and construct and then test systems. It also allows for consideration of plant changes being made in response to other Agency rules affecting the steam electric industry (see Section V.B). Moreover, it enables facilities to take advantage of planned shutdown or maintenance periods to install new pollution control technologies. EPA's decision is also designed to allow, more broadly, for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability, something that public commenters urged EPA to consider. In addition, as requested by industry and states, this final rule and preamble clarify how the ''as soon as possible date'' is determined and implemented for steam electric power plants. The final rule specifies the factors that the permitting authority must consider in determining the ''as soon as possible'' date, and Section XVI.A.1 provides guidance on implementation with respect to timing.

FR 80 (212) November 3, 2015, page 67854

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 1

Comment Excerpt:

As will be explained further below, extending the earliest applicability date is the most important concern for GenOn because if the earliest applicability date is not extended expeditiously, GenOn's Maryland facilities will have to make considerable expenditures installing treatment upgrades to comply with the 2015 ELG Rule before the 2019 Proposed Rule becomes final.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 2

Comment Excerpt:

GenOn requests that EPA extend the earliest applicability date of both the 2015 ELG Rule and the 2019 Proposed Rule to two years after the 2019 final rule becomes effective. In the 2017 Postponement Rule, EPA made clear its intention to further postpone the 2015 ELG Rule compliance dates as necessary so that "the earliest compliance date is not prior to completion of the new rulemaking." 82 Fed. Reg. 43494, 43498 n.6 (Sept. 18, 2017).

Unfortunately, due to the timing of this rulemaking, GenOn may be required to comply with the 2015 ELGs for FGD wastewater and bottom ash transport water before there is a final rule. In the summer of 2018, GenOn's three facilities in Maryland were each re-issued NPDES permits by the Maryland Department of the Environment ("MDE") that require compliance with the 2015 ELGs for FGD wastewater and bottom ash transport water, where applicable, by November 1, 2020.[1] The permits include the earliest applicability date even though EPA said in its own words in the 2017 Postponement Rule that "the action to postpone certain compliance dates in the 2015 Rule is intended to preserve the status quo for FGD wastewater and bottom ash transport water until EPA completes its next rulemaking." 82 Fed. Reg. 43494.

With the 2017 Postponement Rule, EPA wanted to prevent regulated entities from having to incur compliance costs to comply with provisions that might ultimately change as a result of reconsideration of the existing rule. Id. at 43496–98. Without prompt action by the EPA to issue either a revised ELG Rule or a new Postponement Rule, GenOn will be irreparably harmed because it will be required to make expenditures that under the 2019 Proposed Rule may be unnecessary. See Phillip Morris v. Scott, 131 S.Ct. 1, 4 (2010) (Scalia, in chambers) ("Normally the mere payment of money is not considered irreparable, but that is because money can usually be recovered from the person to whom it is paid. If expenditures cannot be recouped, the resulting loss may be irreparable.") (citations omitted).

Therefore, GenOn is requesting that EPA expeditiously extend the earliest applicability date in the 2015 ELG Rule to two years after the expected release of the 2019 final rule or to December 31, 2023 through the same method it utilized for the 2017 Postponement Rule: a separate proposed rule, notice and comment period, and final rule just for postponement of the 2015 ELG Rule's earliest applicability date.[2] EPA plainly has the authority to issue such a postponement rule. The Fifth Circuit recently upheld the 2017 Postponement Rule finding that EPA had a "reasonable basis" for extending the ELG compliance deadlines in response to new information regarding feasibility of the 2015 ELG Rule. Clean Water Action v. United States Envt'l. Prot. Agency, 936 F.3d 308, 315 (5th Cir. 2019).

Without such a postponement rule, facilities like GenOn's in Maryland will be required to comply with the soon-to-be outdated effluent limitation guidelines just as new requirements will be finalized. Compliance by November 1, 2020 does not just mean flipping a switch on November 1, 2020. Compliance requires stations like GenOn's Maryland facilities to procure and install equipment at the cost of tens of millions of dollars well in advance of November 1, 2020. To avoid such costly and potentially unnecessary expenses, EPA must extend the deadline as soon as possible. All of GenOn's Maryland facilities already utilize chemical precipitation, biological systems for nitrogen and phosphorus removal for FGD wastewater and, where applicable, some form of bottom ash transport water recycling. Two stations already utilize ultrafiltration. Therefore, GenOn's economically stressed facilities in Maryland could avoid the expense of three additional 2015 BAT FGD biological systems to marginally improve selenium removal for eight boilers and bottom ash system capital improvements for six boilers.

[1] GenOn filed challenges to MDE's actions. The Maryland Circuit Courts that heard the matters upheld MDE's permit decisions. GenOn has timely filed appeals of those decisions that will be heard by the Maryland Court of Special Appeals in May 2020. However, the permits are not stayed during this process.
[2] In February 2019, GenOn sent a letter to then Acting Administrator Wheeler requesting the same relief. See Feb. 26, 2019 memorandum entitled EPA's Ongoing Reconsideration of the Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category (the ''ELG Rule'' or ''the ELGs''), available on EPA's Docket at No. EPA–HQ–OW–2009–0819.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 5

Comment Excerpt:

It is true that NPDES permits already include re-opener and modification provisions that allow for the modification of permits in the event of changes to the ELGs. It is also true that in the 2019 Proposed Rule "EPA recommends that in cases where a facility's final NPDES permit is issued before these ELGs are finalized and includes limitations for BA transport water and/or FGD wastewater from the 2015 rule, such a permit be reopened as soon as practicable and modified consistent with any rule provisions." 84 Fed. Reg. 64664. However, permit modifications can take months if not years. In fact, in the summer of 2019, GenOn submitted formal permit modification requests for all three stations to MDE seeking extension of the final permits' FGD wastewater and bottom ash transport water compliance deadlines based on the continued regulatory uncertainty as well as GenOn's ongoing studies assessing how and when the stations can comply with the 2015 ELGs. MDE has neither approved nor denied these requests. In fact, MDE has not acted on the requests at all. GenOn has found itself at the mercy of MDE as the clock continues to tick towards the November 1, 2020 compliance deadline.

Without an expeditious and immediate final postponement rule well ahead of the November 1, 2020 deadline, state agencies may not act in time to re-open existing permits and extend the applicability date prior to that date passing. This is very likely to be the case for GenOn's Maryland facilities.

Commenter Name: GenOn Holdings, Inc. (GenOn)
Commenter Affiliation: GenOn Holdings, Inc. (GenOn)
Document Control Number: EPA-HQ-OW-2009-0819-8298-A1
Comment Excerpt Number: 6

Comment Excerpt:

Even without a new postponement rule, GenOn believes that the earliest applicability date of the 2019 Proposed Rule should be extended to two years after the rule becomes effective. GenOn agrees with EPA's assessment that individual facilities may need two to three years from the effective date of a rule to install and begin to operate a treatment system. However, it is far from certain when the final rule will be issued and what it will ultimately require, so companies cannot prudently make large capital investment commitments for significant environmental compliance projects until a regulation is truly final. Extending the earliest applicability deadline will allow companies like GenOn adequate time after the rule becomes final to review the final rule, evaluate the options and how they impact each facility, and make decisions based on the final rule.

Specifically, the 2019 Proposed Rule identifies treatment using chemical precipitation followed by a low hydraulic residence time ("LRTR") biological treatment including ultrafiltration as the BAT technology basis for the control of pollutants discharged in the FGD wastewater. 84 Fed. Reg. 64631. EPA states that the LRTR reductions (1) are comparable to high residence time ("HRTR") reductions; (2) are less costly; and (3) require significantly less to process or facility footprint modifications than the HRTR option. Id. However, because EPA is proposing a new biological technology, the LRTR, facilities will need time to assess the availability, cost, and feasibility of the technology and time to optimize this or other technologies. As a result, the applicability date should be extended as soon as possible in cases where facilities have not yet installed biological treatment to meet the 2015 BAT Limitations for selenium and nitrate-nitrite.

The date should also be extended in cases where the 2015 BAT for biological treatment is planned and installed by November 1, 2020. The proposed more stringent BAT for FGD limitations for mercury may not be met with the 2015 BAT without the addition of ultrafiltration. GenOn's Morgantown Station's FGD wastewater treatment plant is not equipped with ultrafiltration. Vendor performance guarantees for meeting the 2015 BAT for biological systems do not include mercury and arsenic. The redesign and inclusion of an unbudgeted ultrafiltration system into a biological system that is already costlier than the BAT required by the 2019 Proposed Rule is cost prohibitive and impossible by November 1, 2020. In addition, as discussed, GenOn's facilities in Maryland may meet the net generation requirement for the LUB subcategory and would not be required to install 2019 BAT biological systems. Without an extension of the date, the higher cost of the 2015 biological system becomes wholly unnecessary and an additional strain on limited resources.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 17

Comment Excerpt:

If EPA retains BAT for BATW purge based on BPJ, EPA needs to allow more time than the December 31, 2023, date for installation of BAT treatment required. A robust set of discharge pollutant loading data spanning an extended amount of time to account for variability should be collected from the high recycle BATW system after its installation to ascertain the site-specific discharge loadings, a necessary step in determining site-specific BPJ. The statement on Page 64641 about not needing more time as process changes have already occurred is not correct if EPA selects a BPJ pathway to ELGs on BATW purge and the permitting agency requires more treatment than was previously installed. Sites will likely have to expedite schedules just to finish the high recycle portion for BA TW because of the implementation delays engendered by EPA's ELG reconsideration. TVA proposes that should EPA maintain BPJ for determining BAT for BA TW purges, the end date in the "as soon as possible date" for BA TW should be extended at least until December 31, 2025. TVA's projected schedules for completing the recirculation portion of the high recycle system calls into question EPA's suggested duration of 15-23 months for implementation of a *complete* high recycle system (Footnote 74, Page 64641). TVA estimates that implementation of the recirculating portion only is approximately twenty-four to thirty-six months.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 17

Comment Excerpt:

Need for Effective Date parity with FGD BAT limits based on additional time needed for biological treatment lead times

CWLP believes that the timeline for facilities to meet the PSES, which is no later than three years after the effective date of any final rule, is insufficient. Because units complying with BAT for FGD wastewater have until 2025 to comply, there should be some f01m of parity between these two standards. In the proposed rule, USEPA states:

"As with the final BAT effluent limitations, in considering the availability and achievability of the final PSES, the EPA concluded that existing, indirect dischargers need some time to achieve the final standards, in part to avoid forced outages (see Section VIII.C.7). However, in contrast to the BAT limitations (which apply on a date determined by the permitting authority that is as soon as possible beginning November 1, 2020, but no later than December 31, 2023, for BA transport water, and no later than December 31, 2025, for FGD wastewater), facilities must meet the PSES no later than three years after the effective date of any final rule. Under CW A section 307(b)(l), pretreatment standards shall specify a time for compliance not to exceed three years from the date of promulgation, so the EPA cannot establish a longer implementation period. Moreover, unlike limitations on direct discharges, limitations on indirect discharges are not implemented through an NPDES permit and thus are specified clearly for the discharger without delay, without waiting some time for the next permit issuance. ***The EPA has determined that all current indirect dischargers can meet the standards within three years of the effective date of any final rule (which the EPA projects will be issued in the summer of 2020)***." (emphasis added) 84 Fed. Reg. 64,644.

As explained above, CWLP is not clear what universe of sources USEPA was considering in developing the PSES generally, so it is even less clear what USEPA considered in concluding that three years is adequate for all facilities since the only mention is that the two facilities subject to PSES (for Bottom Ash transport water) will not need to meet the full PSES limits as low utilization boilers. This conclusion directly conflicts with USEPA's discussion of the time needed for construction of biological treatment for FGD wastewater to justify a no later than 2025 date for the BAT limits due to an expected backlog for vendors of biological systems.

With regard to the need for additional time for installation of biological systems for FGD wastewater treatment, USEPA says initially that "Information in the record indicates that most facilities should be able to complete all steps to implement changes needed to comply with proposed ... FGD wastewater requirements within 26 to 34 months." FNlOl on page 64,665. USEPA also concluded that more compliance time is needed for FGD wastewater than BA transport water to accommodate "an initial commissioning period to optimize the installed equipment" and because there is expected to be a backlog of biological treatment vendors. See, 84 Fed. Reg. 64,665. However, USEPA also recognized that "Cooperatives and municipalities presented information to EPA suggesting that obtaining financing for these projects can be more challenging than for investor-owned utilities. Under this factor, permitting authorities may consider whether the type and size of owner and difficulty in obtaining the expected financing might warrant additional flexibility up to the 'no later than' date." FNlOl on page 64,665. No such flexibility is provided in the PSES even though the indirect dischargers that CWLP has been able to identify were all municipal utilities. Like most municipal utilities, CWLP will be subject to significant delays that do not impact investor owned utilities for obtaining municipal bonds to finance the project, City Council approval to proceed with the project, state and municipal procurement requirements for designing and building the project and City Council approval of expenditures related to the project. See, Exhibit D for the timelines provided by CWLP's engineering study performed by Burns & McDonnell which provided a range of schedules of 30- 78 months depending on the technology selected and 37 - 53 months for both biological treatment options studied.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 18

Comment Excerpt:

CWLP is a member of APPA and supports their comments on the issues of parity of timelines for compliance with the PSES and incorporates them by reference herein. Failure to find a means to address this timing issue means that USEPA is asking a very small facility to be the early adopter of an expensive technology for no environmental benefit. This advanced effective date will force CWLP to try and squeeze to the front of the line on these biological treatment projects. It's not clear if this will even be possible, but it will certainly increase CWLP's costs and risks and put another weight on the scale in favor of a premature retirement of Unit 4.

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 5

Comment Excerpt:

The proposed deadline may also present problems. With a limited number of suppliers developing technologies to comply with the proposed limits, the December 31, 2025 deadline should remain flexible.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 3

Comment Excerpt:

Move quickly to finalize this reconsideration rulemaking: EPA should move quickly and thoughtfully toward a final rulemaking, as the earliest possible applicability date for bottom ash transport water and FGD wastewater—November 1, 2020—is fast approaching.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 6

Comment Excerpt:

Applicability dates

- We support an extension of the FGD wastewater late applicability date to at least December 31, 2025 and encourage EPA to finalize an identical extension for bottom ash transport water.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 29

Comment Excerpt:

IV. SOUTHERN COMPANY SUPPORTS EPA'S PROPOSAL TO EXTEND THE LATEST APPLICABILITY DATE FOR FGD WASTEWATER TO AT LEAST DECEMBER 31, 2025 AND RECOMMENDS AN IDENTICAL EXTENSION FOR BATW SYSTEMS

A. A Latest Applicability Date of December 31, 2025 for FGD Wastewater is Justified by EPA's "Postponement Rule" and the Time Required to Upgrade Treatment Systems.

On September 18, 2017, EPA issued a final rule entitled "Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Industry" (the "Postponement Rule").[54] In the Postponement Rule, EPA postponed the earliest compliance dates for FGD wastewater and BATW limits from November 1, 2018 to November 1, 2020 in the regulatory definition of "as soon as possible" [55] and signaled its intent to conduct a subsequent rulemaking that might revise the BAT determinations for BATW and FGD wastewater from the 2015 rule. The agency took this interim action in light of "the substantial investments required by the steam electric power industry to comply with the BAT limitations" for BATW and FGD wastewaters, recognizing "that certainty regarding the limitations and standards deserves prominent consideration by the Agency when these limitations and standards may change."[56] EPA postponed the earliest possible compliance date to November 1, 2020, because, at the time, EPA "project[ed] it [would] take approximately three years to propose and finalize a new rule (Fall 2020)."[57] EPA further noted that "[i]f [it] does not complete a new rulemaking by November, 2020, it plans to further postpone the compliance dates such that the earliest compliance date is not prior to completion of a new rulemaking."[58]

The explicit purpose of EPA's 2017 Postponement Rule was "to preserve the status quo for FGD wastewater and bottom ash transport water until EPA completes its next rulemaking concerning those waste streams."[59] EPA did not change the " 'no later than' date of December 31, 2023, [in its 2017 postponement action] because EPA [was] not aware that the 2023 date [was] an immediate driver for expenditures by plants." [60] Instead, EPA provided that it would "take up the appropriate compliance period in its next rulemaking,"[61] which the agency has done. [62]

Taken together, EPA's collective statements and actions from 2017 clearly indicate the agency did not intend for power plants to commit additional resources to comply with the BAT effluent limitations for FGD wastewater and BATW included in the 2015 ELG rule. Instead, EPA expected these regulated facilities to act once the revised rulemaking is complete and their obligations have been clarified.

While the Postponement Rule forestalled mandatory implementation of the 2015 BAT limits, it did not altogether result in a period of inactivity for Southern Company system plants. After the 2015 rule was published, the Southern Company system began collecting data, assessing plant water balances and heavily researching potential treatment technologies that might be capable of achieving EPA's proposed limitations. The Southern Company system and industry peers continued to advance and refine treatment technologies to address potential revised BAT limitations even after the Postponement Rule. In fact, EPA has now incorporated one such technology as the basis of the revised BAT for FGD wastewater. Therefore, the Postponement Rule did not prevent substantial progress toward eliminating use of surface impoundments or toward advancing the technology for treatment of FGD wastewaters.

The Postponement Rule has, however, necessitated a pause in FGD wastewater treatment engineering, design and procurement. The final design of these systems is so dependent on the required BAT limitations that, in the absence of a separate driver such as a state water quality standard, moving forward on substantial engineering, design and procurement of such systems would not be prudent outside the scope of existing federal requirements, such as the CCR rule. Even then, the technology employed due to the CCR rule to stop sending waste streams to impoundments is not necessarily the same as that required to meet limitations imposed by the ELG rule. Therefore, it is reasonable and appropriate that EPA extend the applicability dates for FGD wastewater until at least December 31, 2025 due to the Postponement Rule alone. Ideally, EPA should allow a commensurate amount of time from postponement (September 17, 2017) until EPA finalizes the reconsideration rule. As soon as EPA completes the final rulemaking with revised BAT limitations, FGD wastewater projects can resume in earnest to achieve the final applicability dates.

To avoid confusion on this delay issue, EPA should include in the final rule clear statements that: (1) the 2015 rule's applicability deadlines for the two waste streams in question are no longer applicable; (2) the 2017 Postponement Rule relieved the affected facilities of the obligation to continue planning and investing for compliance with the 2015 rule's requirements for BATW and FGD wastewater; (3) permit writers' establishment of appropriate applicability dates should not ascribe to a facility any obligation to have continued such planning or investment; and (4) the November 1, 2020 date is not a default date a facility must demonstrate is unattainable.

The delay caused by the Postponement Rule is enough on its own to apply the revised FGD BAT limits by no later than December 31, 2025. But that date is independently justified by the time required to upgrade FGD wastewater treatment systems. Based on its experience with the engineering, procurement and construction schedules, the Southern Company system expects projects to implement EPA's proposed FGD wastewater BAT to span a minimum of 48 months to 60 months from the date of a final rule.

Figure 4 sets out a schedule from a facility in the Southern Company system that is illustrative of the time it will take to comply with the requirements of the new final rule. Even with significant overlap between aspects of the project, the full duration is expected to require at least 60 months. This duration suggests a need for implementation through 2025 even if the final rule is promulgated quickly and is not subject to the uncertainty of legal challenges. Furthermore, Southern Company system plants have been utilizing the model schedule set out in Figure 5 for future planning purposes. This model schedule runs 48 months and suggests that a latest applicability date through 2025 is necessary if EPA is not able to promulgate the final rule in the very near future.

In sum, these schedules, coupled with the delay caused by EPA's 2017 regulatory actions, justify the decision to extend the latest applicability date for compliance with the FGD wastewater limitations to the end of 2025.

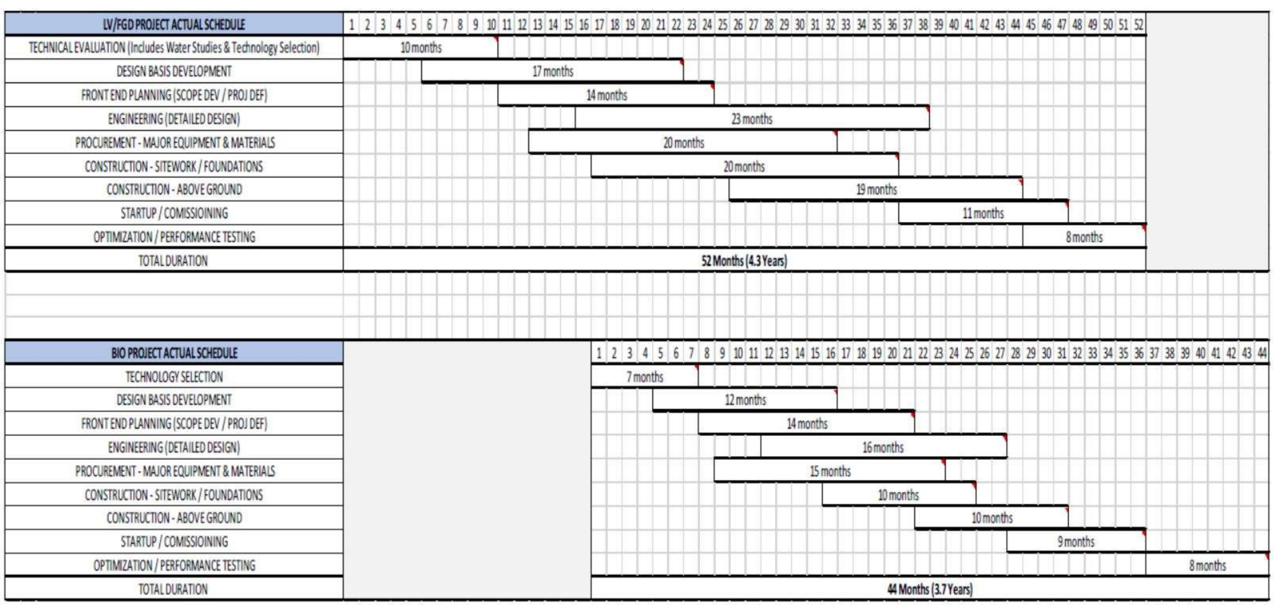

Figure 4. Actual Project Schedule for FGD Wastewater Treatment (CP+LRTR) Project

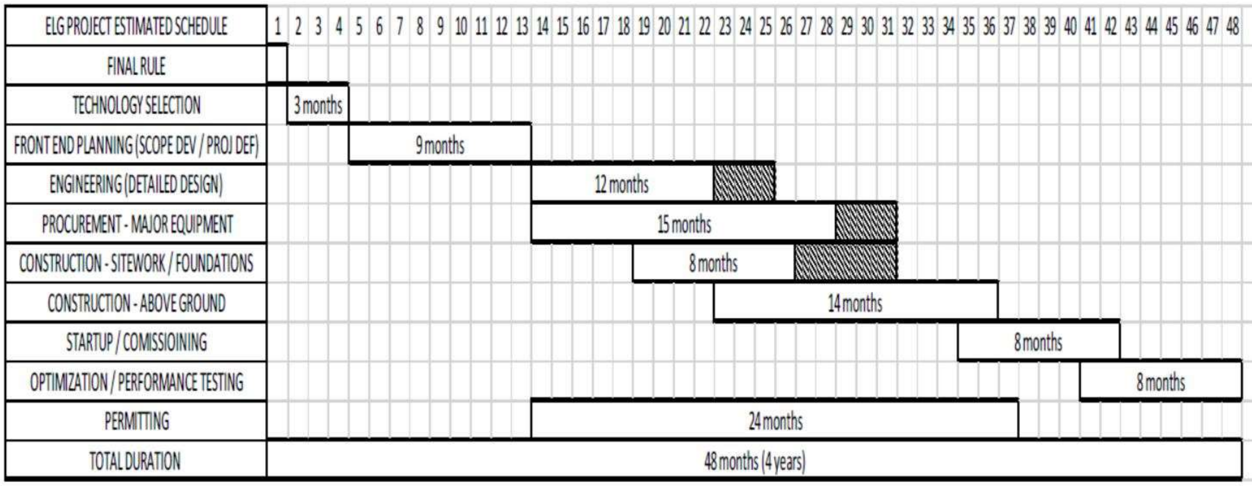

Figure 5. Estimated Project Schedule for Future FGD Wastewater Treatment (CP+LRTR) Projects

54 See generally Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 82 Fed. Reg. 43,494 (Sept. 18, 2017) [hereinafter "Postponement Rule"].
55 Id. at 43,496.
56 Id. at 43,497.
57 Id. at 43,498
58 Id. at 43,498 n.6.
59 Id. at 43,495-96 (emphasis added).
60 Id.
61 See id. at 43,496.
62 See Proposed Rule, 84 Fed. Reg. at 64,673.

Commenter Name: Caitlin McHale
Commenter Affiliation: National Mining Association (NMA)
Document Control Number: EPA-HQ-OW-2009-0819-8327-A1
Comment Excerpt Number: 5

Comment Excerpt:

EPA also should allow permit writers to extend the applicability dates for BATW compliance beyond December 23, 2023.[9] The proposal reports that many facilities have begun making BATW retrofits, but some companies, especially those that relied on the postponement rule, may need additional time to comply.

[9] Id. at 64622.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)

Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 103

Comment Excerpt:

XVIII. EPA Should Encourage Permitting Authorities to Consider the IRP Process when Determining "As Soon As Possible" Dates.

In the Proposed Rule, EPA lays out the factors that permitting authorities must consider when setting "as soon as possible," or applicability, dates for each wastestream. Proposed § 423.11(t). In principle, permitting authorities should consider the IRP process because it is incorporated in existing § 423.11(t) factors (e.g., the time to plan and raise capital (subparagraph (t)(1)) and "other factors" that may be appropriate (subparagraph (t)(4))). But EPA should encourage permitting authorities to consider the IRP process by highlighting the importance of IRP cycles and planning and clarifying that consideration of the IRP process is included in the established § 423.11(t) factors permitting authorities must consider when determining applicability dates.

Some permitting authorities may not put as much weight on considering the IRP process as others without this guidance. So clarifying that its consideration is important and included in the factors permitting authorities must consider would promote consistent, fair implementation across all states.

Moreover, for regulated utilities, it is impossible to submit a retirement or repowering certification to a permitting authority prior to obtaining state utility commission approvals. If permitting authorities do not consider this process or its timing, permittees will have no choice but to ask for special state utility commission hearings that would be required to make plant specific decisions outside the normal IRP processes. The timing and approval of these types of special proceedings would be determined by state agencies not responsible for implementing this rule. Under these circumstances, it would be unrealistic to expect that permittees could regularly, or easily, get the authorization they need to make retirement or repowering certifications via special hearings outside the normal IRP process. Therefore, EPA should encourage permitting authorities to consider the nuances of this process when setting their applicability dates.

XIX. EPA Should Amend the Definition of "Retired From Service."

EPA proposes to define "retired from service" as meaning "the owner or operator of a boiler no longer has, or is no longer required to have, the necessary permission through a permit, license, or other legally applicable form of permission to conduct electricity generation activities under Federal, state, or local law, irrespective of whether the owner and operator is subject to this part." Proposed § 423.11(w). UWAG urges the Agency to amend this definition for several reasons.

As already mentioned in Section XV.A, the Retirement Subcategory should include units that will be retired or repowered. UWAG urges EPA to broaden the definition to include repowered units in the definition and the Retirement Subcategory. If a permittee certifies that it will repower *or* retire a unit by December 31, 2028, then the unit should be allowed to operate until the certified date (i.e., the unit should cease coal-fired operations by December 31, 2028) without meeting any new BAT limits for BATW or FGD.

Also, the proposed requirement for surrender or withdrawal of the licenses/permits necessary to generate electricity is unworkable. It clearly will not work where the unit is being repowered, and many permittees already have both coal-fired and non-coal-fired units at the same generating facilities and thus need to retain their licenses to generate electricity for the noncoal-fired units. Furthermore, permitting authorities decide whether and when to amend permits or licenses to remove the authority to generate for units being retired. In other words, this decision is not entirely within the permittee's control.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 126

Comment Excerpt:

XXIV. UWAG Endorses EPA's Proposed Outside Applicability Dates for FGD Wastewater but Recommends that EPA Change Other Important Aspects of the Applicability Date Provisions.

In the 2015 ELG rule, EPA established a range of applicability dates, the earliest of which was three years after the rule's effective date and the latest of which was eight years after the effective date. The applicability date range in the 2015 rule applied to all waste streams covered by the rule. EPA established this range because the technologies it identified as "best" and on which it based the final limits were not actually "available" immediately upon the 2015 rule's effective date. 80 Fed. Reg. at 67,854. As EPA appropriately recognized, facility owners needed time to plan, design, finance, procure, install, and commission treatment technologies. Id. Setting the earliest deadline three years from the 2015 rule's effective date gave affected permittees time to assess their compliance options, develop a plan, and—crucially—present that plan to their permit writers and obtain an alternative deadline if more time was needed.[252]

That is no less true with regard to this Proposal. Facility owners will first need to make decisions about whether to incur the substantial cost of retrofitting or, instead, to retire and repower or replace the affected unit(s). Those who decide to retrofit will need time to move beyond the nominal design and cost estimates needed to make that threshold decision. As EPA has recognized, and its record demonstrates, retrofitting a facility or unit requires preparing site specific designs (which, for FGD wastewater, may require pilot testing[253]); obtaining capital; obtaining any permission needed to incur retrofit costs and receive reimbursement; procuring equipment; obtaining or modifying environmental or other permits; finding or creating new landfill or other disposal capacity for any solid wastes produced; installing and tying in the equipment (some of which must be done during unit outages); and commissioning the system under real-world operating conditions—a task that may be particularly difficult for units with low utilization rates. See, e.g., 84 Fed. Reg. at 64,641-42, n.74-75 (acknowledging it could take years to raise capital, plan, design, procure equipment, construct, and test systems necessary to comply with the final rule); ERG, *Memorandum re: FGD and Bottom Ash Implementation Timing,* EPA-HQ-OW-2009-0819-8191 (Oct. 17, 2019) ("ERG, Timing Memo") (detailing information from vendors illustrating that it could take years to implement treatment technologies); ERG, *Memorandum re: Technologies for the Treatment of Flue Gas Desulfurization Wastewater,* EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019), App. E, at E-3 ("Frontier conducts pilot studies to optimize chemical dosages, ultrafiltration efficiency, residuals management for a specific plant's operation, and determine the ideal design criteria to remove FGD wastewater pollutants, including selenium and nitrate nitrogen."); EPA, *Notes from Site Visit to Duke Energy's Belews Creek Steam Station on December 13, 2017,* EPA-HQ-OW2009-0819-7337 (Dec. 13, 2017) ("EPA, EPA-HQ-OW-2009-0819-7337") at 3 ("The bottom ash system retrofit requires establishing more than 100 new or updated connections, including those associated with the service water feed, addition of a high-pressure water system, installation of low-pressure tie points, new air valves, the feed system for pyrites and economizer, and redirecting the existing bottom ash sluice pipes."); 2015 Response to Comments, at 8-138 ("EPA's decision with respect to availability of the final limitations is not just a function of time to 'design, build and install' treatment technologies, but is also a function of time needed to raise capital and optimize certain new equipment, as well as an accommodation of changes happening in the industry .… In addition, even if installation of certain equipment requires 'minimal outage time,' … EPA's decision is designed to allow, more broadly, for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability.").

In light of EPA's reconsideration of BATW and FGD wastewater limits, EPA recognized in 2017 that it would have to address the applicability dates for BATW and FGD wastewater BAT compliance in its proposal on reconsideration. 82 Fed. Reg. at 43,498. EPA has now proposed an applicability date range for FGD wastewater of November 1, 2020, to December 31, 2025, and for BATW November 1, 2020, to December 31, 2023. For facilities that volunteer to attempt to implement "beyond BAT" membrane technology that EPA has concluded is neither commercially demonstrated nor nationally available, the Proposal establishes a deadline of December 31, 2028. 84 Fed. Reg. at 64,642, 64,664. EPA also proposes a December 31, 2028 deadline for units that commit to retire by that date and asks for comment on whether that deadline also should apply to facilities that will repower with a fuel other than coal by that date.[254] Id. at 64,640-41.

For units that do not choose to retire or volunteer to meet beyond BAT limits for FGD wastewater, the Proposal, like the 2015 rule, requires dischargers to comply "as soon as possible." Id. at 64,672. EPA defines "as soon as possible" as the earliest date in the specified range, unless the permit writer receives information from the permittee and concludes that a later date is feasible based on one or more of four specified factors. Id. at 64,672.

Unlike the 2015 rule, however, the outside applicability dates for BATW and FGD wastewater no longer harmonize. Instead, the latest BATW deadline is two years shorter than the latest FGD wastewater deadline. UWAG encourages EPA to establish an outside BATW applicability date of at least December 31, 2025, both to provide the time necessary to make and implement reasoned decisions as to BATW and to harmonize the schedules for BATW and FGD wastewater treatment.

Equally important, the earliest date in the proposed range will no longer be three years after the effective date of the final rule. Instead, that November 1, 2020 deadline—the default date that applies unless the permit writer receives information and chooses to act on it—is likely to be at best only a month or two from the point at which the Proposed Rule becomes final.[255] EPA does not explain why this applicability date can reasonably serve as the default applicability date for any units likely to be affected by the final rule,[256] given that only units already having in place all of the technology needed to achieve the final limits as of that date could possibly meet it, and those are not the units EPA identified as affected by the Proposed Rule.

EPA also proposes to modify the definition of "as soon as possible" to require that the permitting authority establish the date only after "receiving site-specific information from the" permittee. Proposed § 423.11(t). EPA says that this change was motivated by information it received from environmental groups suggesting that facilities had filed permit applications based on information for facilities other than the one being permitted, which the Agency says was not the intent of the 2015 rule. 84 Fed. Reg. at 64,665. But EPA does not point to anything in the 2015 rule that precludes use of other information, nor does EPA explain why relevant non-site specific information (for instance, assessing costs across a fleet of units or utilizing information on experience at other similar facilities or studies prepared by reputable engineering experts based on a range of experience) should not also be considered.

UWAG supports EPA's proposed outside deadlines for BAT FGD wastewater limits, at a minimum, and provides recommendations for addressing these important issues raised by other aspects of the proposed applicability dates.

A. Extending the Outside Applicability Date for FGD Wastewater to at Least December 31, 2025 is Essential.

UWAG agrees that the outside applicability date for BAT FGD wastewater compliance should be extended to at least December 31, 2025, as EPA has proposed. Based on UWAG members' experience, unless the units in question already have installed and commissioned treatment technology capable of reliably meeting any applicable limits, they will need every minute of the time EPA has proposed. For example, one UWAG member started its evaluation of an FGD wastewater retrofit project at one of its facilities in January 2016, shortly after EPA promulgated the final 2015 rule. The project milestones included technical evaluation (i.e.,water studies and technology selection); design basis development; front-end planning (i.e., scope development); engineering; procurement of major equipment and materials; permitting; construction; startup/commissioning; and optimization/performance testing. Overall, this member is on track to complete the optimization/performance testing milestone by May 2020, or 52 months after it started its technical evaluation. In addition, the member had to take extraordinary steps to maintain this schedule, including:

- requiring double shifts, seven days per week during most of the construction phase (which added safety risk and increased labor costs);

- procuring equipment before all design information was available;
- entering into “sole source” construction contracts leading to additional costs because the member could not obtain competitive bids for prime structural, mechanical, and electrical work;
- expediting almost every piece of major equipment requiring additional shop evaluations and surveillance, in-person review/approval of piping and instrumentation diagrams, and vendor information to streamline critical information required for design and construction; and
- evaluating and approving new shops because there were not enough fiberglass vendors to keep up with the demand.

Another UWAG member obtained detailed engineering reports and estimates for a FGD wastewater project. Based on the engineering reports and estimates, the company anticipates the project will take approximately 82 months to complete. The major milestones for this project include optimization of the existing system; technology verification (including bench scale and pilot testing);[257] preliminary and detailed design (including equipment and service procurement); obtaining installation permits; construction; commissioning and start-up. The company is also concerned that this project may experience delays due to regional competition for skilled labor.

Another UWAG member obtained a detailed engineering report sketching out how it could retrofit two of its facilities with a chemical precipitation and high residence time biological system to treat its FGD wastewater while EPA was developing its original CCR and ELG rules. The major project milestones would include engineer procurement, process vendor procurement, design, prime contractor procurement, construction, and start-up and commissioning. The company estimates it would take 52 months from engineer procurement to start-up and commissioning to complete its FGD wastewater projects.

In short, constructing FGD wastewater retrofits can take at least five years, not including time to study wastewater characteristics, create new water balance diagrams, conduct FGD pilot studies, and obtain screening-level bids from vendors. Beyond these steps, the facility must know the target limits before proceeding to design the treatment technology.

In some cases, the five years EPA has allotted may not be enough time for companies with multiple facilities affected by the final rule or for those who encounter difficulties with PUC approval, financing, procurement, or landfill availability. Retrofit plans are often affected by factors outside of the company’s control. For instance, changes in tie-in outages resulting from disruptions at the facility, other facilities, or the grid as a whole and delays in major equipment deliveries can significantly impact project schedules. Weather also can be a major factor affecting the timing of construction.

[252] As discussed later in this section, even the three years afforded by the 2015 rule were not always sufficient to ensure that permittees would have a definitive decision from the permit writer regarding an alternative applicability date. Because the rule imposed no duty on the permit writer to act by a date certain, and because many permit writers appeared reluctant to make a determination outside the permit renewal process, permittees often were left in doubt as to whether their request for an alternative deadline would be granted.

[253] Some companies whose facilities are subject to the 2015 rule already had undertaken or contracted for extensive wastewater characterization and pilot testing by the time EPA decided to reconsider the FGD wastewater limits in 2017 and postponed the earliest compliance deadlines to preserve the regulatory status quo (82 Fed. Reg. 43,494, 43,497 (Sept. 18, 2017)). Companies that had not could choose to await EPA action or reconsideration, consistent with the Postponement Rule, or move forward if they determined that awaiting the result of EPA rulemaking process was too risky. As a result, some companies have the wastewater characterization and pilot testing needed to make decisions about technology choice and design, while others do not. Given EPA's decision to preserve the regulatory status quo during reconsideration, it should set applicability dates that do not disadvantage those companies who relied on the Postponement Rule and did not move forward with wastewater characterization and pilot testing, both of which are time-consuming and expensive.
[254] For the reasons discussed in these comments on the proposal for retiring units, UWAG urges EPA to apply the December 31, 2028 deadline to facilities that repower with a fuel other than coal, as well as those that choose to retire, by that deadline.
[255] EPA's latest semi-annual regulatory agenda does not include an anticipated date for finalization of this rule. See OMB, *Agency Rule List – Fall 2019,* https://www.reginfo.gov/public/do/eAgendaMain?operation=OPERATION_GET_AGENCY_RULE_LIST¤tPubId=201910&showStage=longterm&agencyCd=2000&Image58.x=53&Image58.y=8&csrf_token=BEA9DAA54A1D219779CB53D183957D24D6ECA5E897B308D7B86A831BE3C5EB68590EC5E8BA0A801C8411653D6512B42A2242 (last visited Jan. 15, 2020).
[256] As discussed below, EPA removed from its economic impact analysis all units that it anticipated would have in place by December 31, 2028, the technology required to meet the proposed limits. In other words, the costs facilities already had incurred to comply with 2015 rule were eliminated from the regulatory impact analysis, even if those costs were driven by technology requirements that the Proposed Rule would retain.
[257] Even when optimization and technology verification are removed from the project timeline, the company still anticipates a project schedule of approximately 54 months.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 127

Comment Excerpt:

For example, a UWAG member's project experienced many delays out of its control, including the below.

- Abnormal weather patterns caused the loss of 52 day and 25 night work shifts.
- Necessary changes in design basis caused delays because ongoing evaluation of impacts informed decisions about what should be implemented (i.e., specific pollutant reductions).
- The limited construction laydown space specific to the site impacted plans.
- A contractor missed its major equipment delivery deadline by over a year.
- 33 of the over 70 tanks onsite were field fabricated carbon steel tanks that had to be specialty-coated, adding $14 million and three months to the schedule.
- Equipment lead times for electrical switchgears had significantly increased across the country.
- A late NPDES permit location change in 2017 added time to the original schedule and $50 million in costs.

- Scope additions were required for increased redundancy, operability, and reliability, which caused delay and added $23 million in costs.

As the Fifth Circuit recently confirmed in *Clean Water Action v. EPA,* 936 F.3d 308, 316-317 (5th Cir. 2019), nothing in the Clean Water Act precludes EPA from setting a deadline for compliance with second generation BAT ELGs that reflects the real-world circumstances affecting availability and compliance. Based on the facts at hand, EPA should set an applicability date that gives all affected facilities a reasonable chance to comply.[258]

[258] Faced with a deadline they cannot meet, facilities would have to resort to seeking site-specific variances under CWA § 301(c), 33 U.S.C. § 1311(c). This would be a colossal drain on resources, both for the permittees forced to take that route and the permit writers forced to act on those petitions. Equally important, seeking a variance is time-consuming and uncertain, depriving facilities of the certainty that a reasonable, national approach provides.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 129

Comment Excerpt:

C. EPA Should Extend the Outside Applicability Date for BATW to At Least December 31, 2025.

1. The December 31, 2023 Deadline for BATW Will Not Provide Sufficient Time in Some Situations.

Based on information from vendors and from a limited number of facilities, EPA proposes to set an outside applicability date of December 31, 2023, for BATW, having concluded that "facilities may be able to complete design, procurement, installation, and operation of BA transport water technologies" by that date. 84 Fed. Reg. at 64,641. Its preamble ratchets this time frame back even further, positing that "a typical timeframe of 15-23 months" will be sufficient to "raise capital, plan and design systems, procure equipment, and construct a dry handling or closed-loop or high recycle BA system." Id. at 64,641, n.74.

UWAG believes that the maximum time frame EPA has provided (36 months, assuming the rule becomes effective by December 31, 2020) does not include sufficient time for all required steps, is not sufficient to accommodate the full range of situations affected facilities may encounter, and was based on situations that are not representative of most affected facilities.

UWAG is concerned that, in interpreting the information it collected from vendors and individual facilities, EPA has overlooked important factors that warrant setting a later outside deadline for BATW. Neither the vendor estimates nor facility-specific information includes a realistic time frame for all of the requisite steps needed to achieve compliance.

EPA's consultant, ERG, prepared a memorandum summarizing the time frames supplied by vendors. ERG, Timing Memo. The vendor estimates, which start with the request for quotation, anticipate a minimum of 35 months for a remote mechanical drag chain system (a year longer than the high end of the range the preamble characterizes as "typical"). ERG, Timing Memo at 3-4; see also 84 Fed. Reg. at 64,641, n.74. These are *average*, not worst case, estimates. ERG, Timing Memo at 3. Equally important, the vendor estimates cover only some of the steps involved in the decision-making and implementation process. For example, those estimates do not include any time for making the decision about whether, and with what technology, to retrofit (as the flow diagram in the ERG Timing Memo acknowledges); procuring capital and/or permission for reimbursement; obtaining permits; or obtaining new landfill space. Although ERG acknowledges that additional time would be necessary to establish the initial design basis for any MDS or RMDS, it provides only three months for this essential step, based on unspecified "information from the industry." Id. at 1.

The facility-specific information EPA apparently relied on is no more helpful. For some of the facilities in question, information on the timing of BATW retrofits is classified as confidential business information and thus is inaccessible for review in whole or part. See, e.g., EPA-HQ-OW-2009-0819-7341, -7349. Where information is accessible, the date by which the company expects the retrofit to be in service may be specified, but the date on which the process of planning, designing, permitting, procuring, installing, and commencing operation of the system often is not. See, e.g., EPA-HQ-OW-2009-0819-0587, -0588, -7111, -7130, -7139, - 7153, -7173, -7185, -7240, -7254, -7257, -7339, -7340.

That leaves approximately eight facilities for which EPA's record provides some specific, non-anecdotal information on the length of time it took the facility owner to retrofit some form of BATW technology. See EPA-HQ-OW-2009-0819-0580, -1891, -1917, -1920, -4379, -7337, and -7338 (providing information on two facilities). Admittedly, UWAG's review of the record was constrained by the length of the comment period and the resources available. But given the lack of detail available for other facilities, UWAG assumes that the information for these plants significantly affected EPA's selection.

Although EPA says that the time frame it identified will encompass steps such as raising capital, planning, and designing systems, procuring equipment and constructing the system, it is not clear that the time frames it obtained actually included all of those steps. For example, two of the facilities (Allen Steam Station and Belews Creek) had retrofit time frames of 15 and 26 months, respectively. But based on the documentation provided, those time frames do not appear to include time for deciding whether to retrofit or retire/repower units, raising capital, planning, design, or procurement. See EPA-HQ-OW-2009-0819-7338; EPA, EPA-HQ-OW2009-0819-7337. The Seminole Generating Station, by contrast, took a little over 4 years to complete all of the required steps. EPA-HQ-OW-2009-0819-1891.

Also, the steps EPA says its estimate covered do not include all of the steps some facilities may have to take. For example, EPA's time frame for BATW compliance does not include time for making the threshold decision regarding whether to retrofit or retire or repower the unit, *which can only be made once the final rule has been issued*. True, companies can do some planning even before the final rule is issued. But they cannot complete their analyses until they know with certainty what the rule requires.

Beyond this threshold step, there are others not accounted for by EPA's timetable. For example, two facilities for which EPA collected timing estimates ranging from 27-36 months stressed that their estimates did not include time necessary to build or otherwise procure new or expanded landfill space needed to dispose of the resulting solid waste. EPA-HQ-OW-2009- 0819-4379. Moreover, none of the facilities in question appeared to have encountered much competition in obtaining consultant help or procuring the customized drag chains required for a remote mechanical drag chain system. UWAG members report that such components, which cannot be purchased "off the shelf," can take more than a year to obtain once a design has been finalized and an order placed. Competition for scarce resources once the rule is finalized likely will create backlogs in supply, given that only a few vendors currently fabricate these highly customized components.[259] See Tim Miser, *The Coal Ash Rule: How the EPA's Recent Ruling Will Affect the Way Plants Manage CCRs*, POWER ENGINEERING, EPA-HQ-OW-2009-0819-7678 (Feb. 13, 2015) (naming the main vendors, including United Conveyor Corporation, AllenSherman-Hoff, Clyde Bergemann, and Beumer). Also, where permitting or approval of a retrofit is needed, the responsible agency will control the timing of the process. Where some regulatory approval is needed, either to proceed with retrofits at all or to obtain new permits associated with such retrofits (e.g., § 404 permits, zoning permission to bring new areas into development, and the like), the process will take longer.

As UWAG members' experience illustrates, the process often takes far more than the three years EPA has allotted, much less the 15-23 months it says is "typical," especially for regulated companies. When a regulated company decides to invest in a submerged flight conveyor or other BATW system, it must secure approval from its PUC.

For three other UWAG members, the total duration of their RMDS projects ranged from 46 to 51 months. These time frames included the following major project milestones: planning and technology selection; engineering; procuring major equipment;[260] construction; startup/commissioning; and optimization/performance.

Another UWAG member obtained detailed engineering reports and estimates for a BATW retrofit project. Based on the engineering reports and estimates, the company anticipates the project will take approximately 64 months to complete. The major milestones for this project include: optimizing the existing system; technology verification;[261] preliminary and detailed design (including equipment and service procurement); obtaining installation permits; construction; commissioning and start-up. The company is also concerned that this project may experience delays due to regional competition for skilled labor.

In addition, several of the facilities EPA visited are located in North Carolina, which enacted specific laws and regulations designed to expedite conversion to dry or nearly dry bottom ash handling, no matter the cost. See Coal Ash Management Act of 2014, 2014 N.C. Sess. Laws 122. One of the conversions was performed pursuant to a Special Consent Order. See Duke Energy, Letter to North Carolina Division of Water Resources Submitting Quarterly Progress Report from July-September, 2014, Attach. A, for Mayo Electric Generating Plant (Oct. 14, 2014) (updating on completion of a dry bottom ash handling system retrofit resulting from a Special Consent Order issued by the North Carolina Environmental Management Commission). Although UWAG does not question the State of North Carolina's right to establish state-specific requirements that trigger aggressive deadlines, imposing such deadlines nationwide can be extremely costly. Imposing such costs nationally is unwarranted.

In sum, there are good reasons to believe that the proposed December 31, 2023 applicability date for BATW is too short, because it fails to account for important factors that may require more time in some cases.[262]

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[259] Reportedly, one of the principal vendors for this type of technology is now quoting a 26-month lead time on equipment purchases alone.
[260] A drag chain conveyor system is composed of several components which require long lead times for procurement, including the chain, recirculation pump, conveyor, drives, and structural steel. Some of these components may need to be procured from international sources, further extending project timelines.
[261] Even if the project timeline only encompassed preliminary design through commissioning and start-up, it would still take approximately 55 months to complete.
[262] The decision in *Coosa River Basin Initiative v. Dunn* illustrates the site-specific factors that can complicate the choice of technologies, affect implementation time frames, and require coordination among multiple rules. Final Decision, Nos. 1825406, 1826761 (Ga. Office of State Admin. Hearings Oct. 4, 2018).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 131

Comment Excerpt:

2. EPA Should Revise the Outside BATW Deadline to Harmonize with the FGD Deadline.

UWAG urges EPA to extend the latest applicability date for BATW retrofits to at least December 31, 2025, to match the outermost date for FGD wastewater retrofits. This is necessary for two reasons.

First, such a change is necessary to facilitate the reuse of BATW as make-up water for FGD scrubbers where this reuse is appropriately protective of scrubber operation and gypsum beneficial reuse. The 2015 rule allowed, and the current Proposal continues to allow, facilities to use BATW as make-up to the FGD scrubber. See Proposed § 423.13(k)(1)(i), 40 C.F.R. § 423.13(k)(1)(i). But facilities that choose to do so must, under both the 2015 rule and EPA's Proposal, meet the limits specified in § 423.13(g)(1)(i) for FGD scrubber blowdown. As EPA's Proposal properly recognizes, waste treatment facilities for FGD blowdown will not be available for many facilities until December 31, 2025—a full two years later than the latest applicability date EPA has proposed for BATW. Thus, to allow facilities capable of doing so the option of reusing BATW in their scrubbers (or in the FGD system, as UWAG recommends in Section V of these comments), EPA must extend the outermost compliance deadline for BATW to at least December 31, 2025.

Retaining and facilitating this option and others recommended by UWAG is particularly important given the effect that applicability dates had on the industry profile EPA relied on in gauging the costs and economic impacts of its Proposal. That industry profile included only facilities that EPA determined would have to spend resources to come into compliance with the Proposal. EPA removed from the industry profile any facilities that would retire or repower by *December 31, 2028*, as well as facilities that it determined had, or anticipated would complete, technology sufficient to satisfy the Proposed Rule provisions by *December 31, 2028*. See Supplemental TDD, Section 3; ERG 2019 Industry Change Memo. So, if EPA identified a unit that was able to prevent discharges of BATW through a completely closed-loop system, it took that unit out of the industry profile for BATW. But if that unit relies in whole or in part on reusing BATW in the scrubber to avoid discharging, it will not be able to comply with the BATW limits unless it also has in place all of the technology necessary to meet the FGD wastewater limits. Nothing in the record suggests that EPA analyzed that scenario.

Given the intersection between the BATW and FGD wastewater limits, and in light of EPA's ongoing initiatives to encourage reuse of water,[263] UWAG encourages EPA to harmonize the BATW and FGD wastewater applicability dates to promote, rather than discourage, such reuse.

Second, if the final rule retains EPA's proposal to authorize permit writers to set limits on BATW purge on a site-specific BPJ basis (an approach that UWAG urges EPA to delete, for the reasons discussed above in Section III, facilities will not know until those BPJ limits are set what requirements they will have to meet and how much meeting those requirements will cost. Until owners have that information, it will be difficult to decide whether to retire, repower, or retrofit the units in question. Expecting facility owners to make decisions and initiate major investments without a full picture of the costs and feasibility of meeting all of the applicable limits would be unfair and arbitrary. Nothing in the statute authorizes such an approach.

Setting BPJ limits takes substantial time and resources, as discussed in Section III.A. above. Even though nothing in EPA's proposal or in the NPDES regulations imposes deadlines on the NPDES permit issuer to complete the BPJ process, setting the outermost BATW applicability date to December 31, 2025, will at least make it theoretically possible for permittees to obtain a timely BPJ determination from its permit issuer.

Third, the threshold decision about whether or not to retrofit, as well as decisions about the most efficient and effective way to design any retrofit, must be made in light of all of the ELG requirements, and other regulatory requirements, applicable to the units in question. As discussed in these comments on the economic impact of the Proposed Rule, owners of units affected by this rule will have to decide whether to retrofit, retire, or repower based on the total costs of the final ELG rule, including those costs imposed by those aspects of the rule EPA has not revisited in this Proposal or accounted for in the economic impact analysis. The same is true for the design, financing, procurement, and installation of any new waste treatment systems. Facility owners cannot approach such matters piecemeal. To the greatest extent possible, designs must take into account all required changes for all waste streams, lest decisions made for one aspect of the overall project complicate or preclude other aspects. State utility commissions want to understand the total costs likely to be needed to retrofit a unit before giving their blessing, as do financiers who provide the capital for such projects. Procurement of nonspecialized materials is most cost-effective if done in bulk. And, to the greatest extent possible, installation must be timed to match up with regularly scheduled outages, to prevent forced outages with attendant electric grid reliability risks.

All of these factors weigh strongly in favor of setting an outside BATW applicability date of at least December 31, 2025.

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[263] See, e.g., Notice of Availability, Draft National Water Reuse Action Plan, 84 Fed. Reg. 48,612 (Sept. 16, 2019).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 132

Comment Excerpt:

D. Establishing a Default Deadline of November 1, 2020 is Arbitrary and Unnecessary.

EPA's decision to set a "default" applicability date in the 2015 rule made sense because (1) EPA had information in the record suggesting that at least some facilities affected by the rule could comply within the three-year period anticipated by that deadline and (2) the structure of the applicability date provision gave permittees time to seek an alternative date. Neither is the case for EPA's proposed November 1, 2020 deadline.

The November 1, 2020 deadline is simply an artifact of the Postponement Rule in which it was set. 82 Fed. Reg. 43,494. In that rulemaking, EPA made no effort to determine a date by which facilities could reasonably be expected to achieve compliance with any limits EPA might establish after reconsideration. Instead, the November 1, 2020 deadline was based on the amount of time EPA expected to need to complete further rulemaking. Id. at 43,498.

According to the Supplemental TDD and the ERG 2019 Industry Change Memo, the facilities affected by EPA's final rule will be those that have not yet complied with the final rule and are not expected to have reached compliance (or ceased to discharge at all) before December 31, 2028. To the extent EPA has any information on the dates by which the technology needed to achieve the proposed limits might reasonably be available, it relied on that information to set the outside deadlines, not the November 1, 2020 deadline.

The November 1, 2020 default deadline therefore must be deleted entirely or changed to one that can be met by the majority of facilities affected by the rule while allowing those that cannot meet the deadline a fair chance to seek an alternative schedule

Given the time frames in question and the fact that these are nationally applicable, categorical requirements, it would be entirely reasonable and consistent with the statute and past Agency practice for EPA to establish a single, outside deadline of December 31, 2025, for BATW and FGD wastewater and to apply that applicability deadline to all facilities in the category. Facilities that already have all of the technology to comply will continue to use that technology, as dictated by EPA's NPDES rule prohibiting the bypass of treatment technologies except under limited circumstances, 40 C.F.R. § 122.41(m).

Setting a single deadline would avoid the procedural problems inherent in setting a default date without also establishing procedural requirements requiring permit writers to act promptly and, in some cases, outside the standard permit renewal process on requests for alternative deadlines. Permittees whose permits were not slated for imminent renewal reported that permit writers often were reluctant to make decisions on requests for alternative schedules, for fear of public criticism or simply because of other agency priorities. But certainty regarding the deadline for compliance is an absolute necessity for technology planning and financing. Setting a single, adequate deadline for all facilities would solve this problem, without adding burdens to state permit writers.

If EPA decides to retain the proposed approach of setting an initial "as soon as possible" deadline as well as an outside deadline, it should take the following steps. First, it must select a deadline that gives facilities a fair chance either to comply or seek a later deadline. Second, it must provide clear instructions to the states as to when and how decisions on alternative deadlines should be made, especially where the permit is not up for renewal and no permit modification is otherwise sought.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 133

Comment Excerpt:

E. EPA's Proposed Amendment of § 423.11(t) is Unwarranted.

EPA proposes to amend the "as soon as possible" definition from the 2015 rule to require that permittees must, for their justification of site-specific applicability dates, provide site specific information only. EPA says eNGOs informed it that facilities had filed permit applications based on information for facilities other than the one being permitted, which was not the intent of the 2015 rule. 84 Fed. Reg. at 64,665.[264] Non-facility information can be critical in setting ELG applicability dates, particularly due to the ability to raise capital and impacts to labor availability or craft shortages that implementing multiple, simultaneous projects may cause.

EPA's proposed revision is unnecessary, unfairly burdensome, and inconsistent with NPDES permit application practice. Necessarily, a facility that has not yet performed a retrofit will look to the experience of other, similar facilities or to published literature for information on design, performance, cost, and timing. It then adapts that information as necessary to its circumstances.

Moreover, some relevant information, such as regulatory developments, is inherently general, not site-specific. Thus, it is commonly the case that facilities planning for new retrofits provide data to their permitting authority regarding how the retrofits are intended to function and the likely attributes of their wastewater. Often, the best information available on the system's performance will be data from other facilities, such as a sister facility with the same equipment as the one being permitted. Therefore, limiting the use of such data is neither advisable nor fair. Equally important, if facilities must start from scratch to prepare entirely new assessments based only on site-specific information, the additional costs and burdens will be substantial.

The permitting authority has full discretion to ask for more or different data than that provided by the permittee. To arbitrarily exclude data from other facilities hampers the exercise of that discretion and deprives the permitting authority of useful information and context.

There is another reason why use of information from a range of sources, including other facilities, plays an important role in setting deadlines. EPA's proposed approach establishes a default deadline and puts the burden on the permittee to seek an alternative deadline. If EPA retains that approach, then, even if it sets a more reasonable initial deadline, permittees will have to set to work immediately to make decisions and assess how much time they will need to achieve compliance. If they do not already have a detailed site-specific assessment, they either will have to look to the experience of others to estimate what they will need, or take the time to commission a site-specific study, which would be extremely burdensome in terms of both time and resources. That makes no sense.

Instead of revising the rule as proposed, EPA should continue to allow permittees to do what the Agency and its consultants have done in developing proposed deadlines—rely on the experience of some facilities to project what may be needed at other specific sites that have not yet developed data or implemented technology.

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[264] In reviewing the 2015 rule, it appears EPA was open to considering information related to facilities other than the one being permitted. For instance, EPA explained in the 2015 Regulatory Impact Analysis that the compliance "implementation window is in part intended to ensure no adverse effects on electricity availability" and thus allows plants to meet the new standards "in a somewhat staggered fashion." 2015 RIA at 3-4. Also, according to EPA, the applicability date periods were "designed to allow, more broadly, for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability, something that public commenters urged EPA to consider." 80 Fed. Reg. at 67,854. If permittees and permitting authorities should work together to avoid impacts to electricity availability and to consider unit outages, it only makes sense to do so across units, and this requires information about units other than the one being permitted.

There are also other factors that require the consideration of information from other units or facilities. For example, under 40 C.F.R. § 423.11(t), permit writers are to consider the impacts of the CCR rule on the facility being permitted. Facilities that intend to make use of the alternative closure provisions of the CCR rule must evaluate both on-site and off-site alternative disposal capacity. 40 C.F.R. §§ 257.103(a)(1), (b)(1). The availability of this capacity—or the timing of construction of new disposal capacity off-site—may be relevant to the timing of ELG-driven retrofits. Again, this is not site specific information, but it is information that might well inform the permitting authorities' judgment about timing of ELG retrofits. This is another reason why limiting the information a permit writer may consider to "site-specific" information is infeasible.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 137

Comment Excerpt:

XXVI. The Industry Needs the Certainty that EPA Can Provide by Expeditiously Finalizing This Rule and Taking Appropriate Steps to Ensure that Permits Issued Based on the 2015 Rule Are Modified Accordingly.

The 2015 ELG rule, as amended by EPA's 2017 Postponement Rule, 82 Fed. Reg. 43,494, sets the range of applicability dates for BAT retrofits from November 1, 2020, to December 31, 2023. Those dates are fast approaching. As EPA recognizes[275] and UWAG's comments confirm, coming into compliance requires a substantial amount of time and advance planning. Consistent with EPA's 2017 Postponement Rule, which was explicitly designed to preserve the regulatory status quo and avoid potentially unnecessary investments otherwise required to comply with the 2015 rule,[276] many affected owners have postponed making final decisions regarding whether or not to retire, repower, replace, or retrofit existing coal-fired units.[277]

Although EPA relied, in part, on NPDES permits and applications to update its industry profile,[278] it is not clear whether the record includes comprehensive information on the number of facilities currently holding NPDES permits containing applicability dates based on 2015 rule. A number of UWAG members report holding such permits.[279]

In some cases, the applicability deadlines occur well before December 31, 2023. Some UWAG members have applicability dates as early as September 2021 for FGD wastewater limits and January 2021 for BATW limits based on the 2015 rule. Assuming EPA's final rule includes all or some deadlines later than those imposed by the 2015 rule, facilities holding NPDES permits based on the 2015 rule will need to obtain permit modifications immediately upon issuance of the final rule.

Although EPA is not the permit issuing authority in most states, it can and should include in the final rule a clear statement encouraging all NPDES permitting authorities to move promptly, upon receipt of a timely request for permit modification from the affected source, to modify the permit to provide for deadlines based on the final rule. Indeed, the preamble to the Proposed Rule encourages permitting authorities to reopen and modify permits based on the 2015 rule as soon as practicable. 84 Fed. Reg. at 64,664. In the preamble to the final rule, EPA should state clearly that (1) the 2015 applicability deadlines for the two waste streams in question are no longer applicable; (2) the 2017 Postponement Rule relieved the affected facilities of the obligation to continue planning and investing for compliance with the 2015 rule's requirements for BATW and FGD wastewater; (3) the permitting authority's establishment of the appropriate applicability date should not ascribe to the facility any obligation to have continued such planning or investment; and (4) unless the facility already has all of the necessary technology in place, the November 1, 2020 date is not to be set as a default date that the facility must demonstrate is unattainable.

In the meantime, facilities with NPDES permit deadlines on or earlier than 2023 face serious compliance issues that will only be exacerbated the longer it takes EPA to issue a final rule. Given the amount of time it takes to finance, acquire, install, and commission the technologies on which both the 2015 and proposed 2019 rules are based, facilities facing even a 2023 deadline must begin to act soon if they choose to retrofit and hope to comply by that deadline. Yet given the rigors of the administrative process, it is hard to imagine that EPA will be in a position to issue a final rule much sooner than late summer 2020. Even if permitting authorities act promptly to modify applicability dates, that process (which requires a 30-day comment period as well as consideration of, and response to, comments) is time-consuming.

Recognizing this dilemma, EPA's 2017 Postponement Rule anticipated that EPA would issue rules further postponing the applicability deadlines if it did not complete rulemaking by November 1, 2020.[280] But by the time EPA knows whether or not it will be in a position to issue final regulations setting new deadlines, it will be too late to do justice to those permittees whose NPDES permits already include deadlines before December 31, 2023. Despite EPA's clear statements about the purpose of the Postponement Rule, those facilities must, as a practical matter, start making choices and investments soon or assume the very real risks that EPA will not finalize a revised rule soon enough to make permit modification possible or that the state will not act in a timely fashion on a permit modification request.

There is a straightforward solution to this problem, it is consistent with current law, and it would not require further rulemaking. EPA can and should instruct NPDES permitting authorities that, pursuant to 40 C.F.R. §§ 122.62(a)(2) and 423.11(t), permittees may request, and permitting authorities may issue, modified applicability deadlines of up to December 31, 2023 (the 2015 ELG Rule's outermost deadline), based solely on the substance and timing of EPA's proposal.[281] The pendency and timing of EPA's proposal and the fact that a final rule will not likely be issued until late summer 2020 at the earliest, ensuring permittees will not have notice of that rule and a fair chance to make crucial decisions, are appropriate "other factors" on which revised applicability dates may be set under the 2015 rule. EPA should post a statement to this effect on its website and should encourage permitting authorities to move promptly on any permit modifications they receive consistent with this statement.

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[275] See 84 Fed. Reg. at 64,641-42, n.74-75 (acknowledging it could take years to raise capital, plan, design, procure equipment, construct, and test systems necessary to comply with the final rule); see also ERG, Timing Memo (detailing information collected from vendors regarding treatment technologies illustrating that it could take years to implement those technologies).

[276] EPA's stated purpose in adopting the 2017 Postponement Rule was to authorize permit writers to select applicability dates that will avoid any expenditures to comply with the 2015 ELGs for FGD wastewater and BATW until EPA completes further rulemaking for those waste streams. 82 Fed. Reg. at 43,497. The preamble accompanying that rule indicated that EPA would conduct further rulemaking to revise the applicability dates if it has not completed its reconsideration of the FGD wastewater and BATW limits by November 1, 2020. Id. at 43,498, n.6.

[277] As discussed in Section XXIV, some facilities went forward with technology changes mandated by the 2015 rule, perhaps because their NPDES permits included limits based on that rule and, in light of delays in the reconsideration process, they felt they had little choice but to begin making the investments mandated by that rule.

[278] See ERG 2019 Industry Change Memo; see also ERG, EPA-HQ-OW-2009-0819-7374, Table 2 (stating "the information presented here includes plants/units that are not affected by the 2015 ELGs...").
[279] See, e.g., UWAG, Letter to EPA Delivering Supplemental Information in Support of its Petition for Rulemaking To Reconsider And Administratively Stay the Effluent Limitations Guidelines and Standards For the Steam Electric Power Generating Point Source Category, EPA-HW-OW-2009- 0819-6480-A4 and -A5 at 11 (Apr. 13, 2017).
[280] 82 Fed. Reg. at 43,498, n.6.
[281] Without such guidance permitting authorities may be hesitant to modify applicability dates in existing permits as evident from UWAG members' recent experience. In addition, it may make sense for some permittees to submit requests for modification shortly after the final rule's effective date. But many other permittees may need such modifications sooner than that and EPA's guidance would assist permittees in those circumstances.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 30

Comment Excerpt:

B. EPA Should Synchronize Late Applicability Dates for FGD Wastewater and BATW.

If EPA moves forward with the proposed 2025 date for final implementation of FGD wastewater BAT, it should extend the latest applicability date for BATW BAT to December 31, 2025 as well. EPA recognized the need to harmonize applicability dates in the Postponement Rule. In the agency's words, "it would be reasonable for permitting authorities to consider the need for a facility to make integrated planning decisions regarding compliance with the requirements for all of the wastestreams[.]"[63] EPA should continue to recognize the need for integrated planning among all wastestreams in its final rule.

That need is particularly acute with respect to BATW and FGD implementation. Building on the work done to implement the 2015 rule, many facilities have made substantial progress in reducing the amount of BATW discharged, as EPA has recognized.[64] But in some cases this progress depends on the ability to send some bottom ash transport water to the FGD system for use as makeup water.[65] This makeup water, in turn, will be subject to the newly revised numeric limits for FGD wastewater.66 Given the long uncertainty over these limits, their recent change, and their stringency, facilities are unlikely to have installed the biological treatment or other technology needed to meet them, which is why EPA has rightfully extended the latest applicability date for this wastestream through 2025. But the regulatory text does not clearly grant any additional time beyond 2023 *for the makeup water* to comply with the FGD limits.[67] Thus, a potentially unintended consequence of extending the late applicability date for FGD wastewater without also extending the late applicability date for bottom ash transport water is the compromised ability to utilize bottom ash transport water as FGD scrubber makeup water.

If EPA were to retain the 2023 late applicability date for bottom ash transport water, however, facilities with BATW systems designed to discharge to the FGD scrubber vessel would not be able to do so. Therefore, EPA should extend the late applicability date for bottom ash transport water to match the extended late applicability date of at least December 31, 2025 for FGD wastewater. Alternatively, EPA should clarify, in the final regulatory text, that both the numeric limits and the applicability dates for FGD wastewater apply to bottom ash transport water used as makeup water.

63 Postponement Rule, 82 Fed. Reg. at 43,498.
64 Proposed Rule, 84 Fed. Reg. at 65,641.
65 EPA has also proposed authorization to discharge up to 10% of the volume of the bottom ash transport system. Despite this proposal, use of BATW as makeup water might still be necessary to comply with the 10% limit. Sending BATW to the FGD system, where it must eventually comply with numeric limits on certain constituents, might also be preferable from an environmental standpoint.
66 Id. at 64,674 (proposed 40 C.F.R. § 423.13(k)(1)(i)).
67 See id.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 31

Comment Excerpt:

C. EPA Should Not Base the "As Soon As Possible" Determination on Site-Specific Information Only.

The proposed amendment to 40 C.F.R. § 423.11(t) directs the permitting authority to establish an "as soon as possible" date "after receiving site-specific information from the discharger[.]"[68] Site-specific information should be utilized in permit development, when available, but EPA should make clear that it is not the only basis for determining an "as soon as possible" date. A requirement to use only "site specific" information risks losing cost-effective research-and-development opportunities and ignoring critical system-level resource planning and resource allocation needs. The permitting authority has full discretion to ask for more or different data than that provided by the permittee. This proposed amendment could hamper that discretion by limiting their review and consideration to "site specific" information only. EPA should clarify that this is not the case.

The Southern Company system has invested tens of millions of dollars in a Water Research Center conducting research and development on treatment technologies at Georgia Power Company's Plant Bowen. This research is meant to inform ELG implementation at numerous Southern Company system facilities, and the proposed change could be interpreted to exclude the information gleaned by this work, or other generally applicable research, in development of permits for other facilities. That cannot be what EPA intended. Similarly, industry has widely relied on the ability to use information across facilities since promulgation of the initial ELG rule. Entities like the EPRI have conducted their own research on treatment technologies, and this information should not be excluded from review by the permitting authority.

Capital and resource allocation decisions are made across an entire fleet, not necessarily or always on a "site-specific" basis. To a significant extent, this fleet-wide planning is already inherent in the existing definition of "as soon as possible"—namely, the need for "time to expeditiously plan . . . design, procure, and install equipment to comply with the requirements of this part." The regulated utility resource planning process often requires information for the larger fleet and market, and that process may impact the ability to plan, design, procure and raise capital for ELG implementation. A "site-specific" requirement suggests that the permitting authority cannot consider the system-wide information that drives this process.

Outages are also planned across the entire fleet, and any "site-specific" outage time depends on events and conditions at other facilities. As EPA has recognized, any implementation strategy must allow "for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability[.]"[69] When one facility requires an outage to install new technology (or conduct maintenance and tune-ups required by other regulations), that may necessarily delay similar outages at other facilities in the fleet to supply sufficient power. Conversely, a facility that plans for an early outage might need to delay it if, for example, critical vendors are unavailable, with the result that outages at other facilities might be moved up. This interdependence has subtle but important implications for ELG implementation. The precise sequence and timing of outages across the fleet is subject to uncertainty; as a result, each individual facility must have some flexibility in planning for its own outages to implement new technology. To provide that flexibility, the permitting authority should have full discretion to accommodate the possibility of outages across several plants. Finally, supply constraints are applicable to multiple facilities by their very nature. Individual plants, even those in the same fleet, may need to compete for the same vendors, engineers, equipment, or supplies. These third parties cannot necessarily meet full demand simultaneously. As with outages, the permittee cannot predict in advance which plant will face supply constraints or when. This requires some flexibility in implementation planning across multiple plants to ensure each can accommodate potential delays.

For these reasons, EPA should clarify that permit writers must consider all relevant information submitted by the permittee, not merely "site-specific" information.

68 See id. at 64,672 (to be codified at 40 C.F.R. § 423.11(t)).
69 2015 Rule, 80 Fed. Reg. at 67,854; see also Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 78 Fed. Reg. 34,431, 34,480 (proposed June 7, 2013) ("[T]o avoid any impacts on the consistency and reliability of power generation, outages at multiple facilities in one geographic area would need to be coordinated, which could result in the need for more time.").

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 1

Comment Excerpt:

Talen Energy (Talen) appreciates EPA's reconsideration of the FGD wastewater and BATW provisions of the 2015 ELG rule. As a first priority, Talen Energy urges EPA to finalize this rule as soon as reasonably possible, consistent with all necessary administrative procedures.

Facilities, such as the ones owned and operated by Talen, subject to the 2015 rule have been waiting since April 2017, when EPA granted the reconsideration, for further direction on the two waste streams being reconsidered. Two of Talen's coal fired plants have received National Pollutant Discharge Elimination System (NPDES) permits with ELG applicability dates that are fast approaching. Our other owned and operated coal fired plants are in the permit renewal process. All of these Talen facilities subject to the ELG rule are also subject to the Coal Combustion Residuals ("CCR") rule, which is undergoing its own process of amendment. The certainty of a final ELG rule along with the CCR rule changes are critical for Talen Energy to appropriately plan and obtain funding for any needed changes or upgrades to these facilities required for their continued operations.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 4

Comment Excerpt:

The Corporation also encourages EPA to expeditiously finalize this rulemaking to help ensure future regulatory certainty.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 18

Comment Excerpt:

Moreover, EPA's current proposal would delay compliance with the VIP limits significantly beyond the compliance date for its mandatory BAT standard (2028 vs. 2025). In the 2015 rule, EPA did not provide an additional extension but rather allowed facilities to comply by the end of the standard "no later than" period. The current proposal allows facilities to avoid complying with protective effluent limits for eight more years, creating a significant harm to waterways and communities in the meantime.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 13

Comment Excerpt:

V. THE COMPLIANCE DEADLINES MUST BE EXTENDED FOR BOTH REVISED EFFLUENT DISCHARGE LIMITATIONS.

Oglethorpe Power supports EPA's proposal to extend by two years the compliance deadline for installing FGD wastewater treatment systems. This additional time is needed for many electric utilities to install major new treatment technologies (such as chemical precipitation combined with biological treatment and ultrafiltration) for meeting the new FGD effluent discharge limitations.

As EPA correctly recognizes in the Proposed Rule, retrofitting a generating facility or unit with this reference control technology requires preparing site-specific designs (which, for FGD wastewater, may require pilot testing[14]); obtaining capital; obtaining any permission needed to incur retrofit costs and receive reimbursement; procuring equipment; obtaining or modifying environmental or other permits; finding or creating new landfill or other disposal capacity for any solid wastes produced; installing and tying in the equipment (some of which must be done during unit outages); and commissioning the system under real-world operating conditions—a task that may be particularly difficult for units with low-utilization rates.[15]

By contrast, the Agency is not proposing to extend the compliance deadline for meeting the new effluent discharge limitations applicable to BA transport water. This means that the latest deadline for meeting the BA transport limitations is two years earlier than the latest FGD wastewater deadline. Oglethorpe Power believes that the proposed compliance deadline of December 31,

2023 is too short. Most importantly, it does not provide sufficient time for many coal-fired EGUs to convert to dry ash handling or install a partially closed-looped wet ash handling system for transferring the BA from the boiler to the coal ash disposal facilities. Furthermore, we believe it makes good policy to harmonize the compliance schedules for both FGD wastewater and BA transport water by extending the compliance deadline for BA transport water from December 31, 2023 to December 31, 2025. Harmonizing the deadlines for BA transport water and FGD wastewater also will allow for affected EGUs to reuse the BA transport water as make-up water for the FGD scrubbers.

14 Some companies whose facilities are subject to the 2015 rule already had undertaken or contracted for extensive wastewater characterization and pilot testing by the time EPA decided to reconsider the FGD wastewater limits in 2017 and postponed the earliest compliance deadlines to preserve the regulatory status quo (82 Fed. Reg. 43,494, 43,497 (Sept. 18, 2017)). Companies that had not could choose to await EPA action or reconsideration, consistent with the postponement rule, or move forward if they determined that awaiting the result of EPA rulemaking process was too risky. As a result, some companies have the wastewater characterization and pilot testing needed to make decisions about technology choice and design, while others do not. Given EPA's decision to preserve the regulatory status quo during reconsideration, it should set applicability dates that do not disadvantage those companies who relied on the postponement rule and did not move forward with wastewater characterization and pilot testing, both of which are time-consuming and expensive.

15 See, e.g., 84 Fed. Reg. at 64,641-42, n. 74-75 (acknowledging it could take years to raise capital, plan, design, procure equipment, construct, and test systems necessary to comply with the final rule).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.

Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 33

Comment Excerpt:

d. FGD limits must be implemented without further delay.

EPA should not delay ELG compliance deadlines until 2025. There is no reason to drag out implementation of the rule because utilities already have been preparing to comply with the rule since 2015. In fact, some sites already have installed treatment technologies that meet the 2015 requirements and many others have evaluated treatment options and begun planning and implementation. For example:

- In North Carolina, Duke Energy successfully deployed a zero liquid discharge system at its Mayo Plant, and it has been operating biological treatment systems at its Belews Creek, Roxboro, Allen, and Marshall sites.
- In Tennessee, the Gallatin site "is a dry FGD operation and does not discharge FGD wastewater."[62]
- In South Carolina, Dominion Energy South Carolina (formerly SCE&G) has reportedly already achieved compliance with the Rule at Cope Station.[63] Cope Station uses dry ash handling and has a dry scrubber system and thus produces no fly ash, bottom ash or FGD wastewater discharges.[64] And as early as 2016, Dominion began evaluating compliance pathways for the 2015 Rule's FGD wastewater requirements for its Wateree Plant and Williams Station.[65]
- In Virginia, the compliance date for development of a biological treatment component at its Chesterfield site in accordance with the ELG Rule is set for March 29, 2022.[66] Virginia DEQ established that deadline—more than 20 months ahead of the 2015 Rule's outer deadline—based on Dominion's own plans, designs, and schedules.[67] Although commenters argued compliance could be achieved even sooner, even Dominion's schedule establishes the plain fact that compliance will be readily achieved well in advance of the outer deadline.[68]

[62] Tenn. Dep't of Environment & Conservation, Modified NPDES Permit TN0005428, R-9 (Oct. 12, 2018), available at http://environmentonline.tn.gov:8080/pls/enf_reports/f?p=9034:34308:::NO:RIR:IREQ_PERMIT_NUMBER,IREQ_FILE_TYPE:TN 0005428,Permit (Attachment 13).

[63] Response of SCE&G to S.C. Coastal Conservation League and Southern Alliance for Clean Energy's First Data Request, South Carolina Public Service Commission, Dkt. 2017-9-E, Resp. 2h at p. 4 (Apr. 11, 2016) ("Cope Station is already compliant with the EPA's effluent limitation guidelines.") (Attachment 14).

[64] See SCE&G 2019 Integrated Resource Plan, South Carolina Public Service Commission, Dkt. No. 2019-9-E, at 25, 27 (Feb. 8, 2019), available at https://dms.psc.sc.gov/Attachments/Matter/9f865fe4-f830-4ccd-af0b9ee5bcb25c10 (Attachment 15).

[65] Wateree and William ELG Compliance Strategy Technology Screening Workshop, Meeting Summary, prepared by ch2m (Oct. 5, 2016) (Attachment 16).

[66] Letter from Michael P. Murphy, Virginia Department of Environmental Quality, to Pamela F. Faggert, Vice President and Chief Environmental Officer, Dominion Electric and Power Company, RE: VPDES Permit No. VA0004146, Dominion Chesterfield Power Station (Sept. 23, 2016) (enclosing VPDES permit), available at http://www.deq.virginia.gov/Portals/0/DEQ/Water/PollutionDischargeElimination/Coal_Ash/Chesterfield/VA0004146FinalPermit.pdf?ver=2016-10-31-163846-840 (Attachment 17).

[67] Virginia Department of Environmental Quality, VPDES Permit Fact Sheet, Dominion Chesterfield Power Station, at 21 (Sept. 23, 2016), available at http://www.deq.virginia.gov/Portals/0/DEQ/Water/PollutionDischargeElimination/Coal_Ash/Chesterfield/VA0004146FinalFactSheet.pdf?ver=2016-10-31-163847-060 (Attachment 18).

[68] Virginia Department of Environmental Quality, Response to Comments, VPDES Permit No. VA0004146, Dominion Chesterfield Power Station, at 2-3 (Aug. 23, 2016), available at http://www.deq.virginia.gov/Portals/0/DEQ/Water/PollutionDischargeElimination/Coal_Ash/Chesterfield/ResponsetoPublicComments08.19.16.pdf (Attachment 19).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 34

Comment Excerpt:

Moreover, multiple utilities have made public statements that they will be able to comply with the more stringent requirements of the 2015 Rule on time. For example, Duke Energy told investors the company is "well-positioned to meet the majority of the [ELG Rule's] requirements."[69] Georgia Power Company, in a filing accompanying its 2019 Integrated Resource Plan, told regulators: "Based on current requirements [for FGD wastewater] in the rule, the Company has developed a design, procurement, construction, and commissioning schedule that provides a strategy to be in-compliance by the latest applicability date of December 31, 2023."[70] In 2016, Georgia Power expressed confidence in its ability to meet ELG deadlines at Plant Hammond: "Georgia Power and Plant Hammond have consistently met or exceeded all environmental regulations, and Plant Hammond's compliance with the Effluent Limitation Guidelines is no exception."[71]

Indeed, Georgia Power should be well-situated to meet the 2023 outer deadline for FGD wastewater given it began evaluating treatment options in 2012 at the Water Research Center at its Plant Bowen. Georgia Power's parent company, the Southern Company has spent the good part of a decade and millions of dollars developing and evaluating treatment methods at the Water Research Center, including biological treatment.[72] Georgia Power has been considering a range of treatment technologies, including zero liquid discharge and physical-chemical treatment followed by General Electric's ABMet technology.[73] In a 2018 permit renewal application for Plant Scherer, Georgia Power estimated that "[a] single FGDW treatment system with physical, chemical, and biological treatment will take, on average, four years to *complete* detailed design engineering, procurement of equipment and materials, and construction."[74] Four years from 2018 would mean that the company estimated it could complete construction of a FGD treatment system for Plant Scherer by 2022.

[69] Duke Energy Corporation, U.S. Securities & Exchange Comm'n Form 10-K, Comm'n file number 1-32853, at 63, available at https://www.duke-energy.com/_/media/pdfs/our-company/investors/de-annualreports/2017/2017annualreport.pdf?la=en (for fiscal year ending Dec. 31, 2017) (Attachment 20).

[70] Georgia Power Company, 2019 Integrated Resource Plan Doc. Filing #175473, Environmental Compliance Strategy Update for 2019 filed before the Georgia Public Service Commission Jan. 31, 2019 ("GPC ECS 2019"), at 66, available at https://psc.ga.gov/search/facts-document/?documentId=175473 (PD 2019 IRP, PD Vol 2, 6 PD ECS) (Attachment 21).

[71] Georgia Power Company's Plant Hammond Effluent Limitation Guidelines Rule Applicability Timing - NPDES Permit Application 2016, at 5 (Attachment 22).
[72] Id. at 1, 3.
[73] Plant Scherer Effluent Limitations Guidelines Rule Applicability Timing, NPDES Permit Application 2018 at p. 5 ("Scherer ELG Timing Memo") (Attachment 23) (The WRC also evaluated technologies from Frontier Water Systems, Inotec, Evoqua, and Liberty Hydro, and "an in-house Biofilm technology.").
[74] See id. (emphasis added).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 35

Comment Excerpt:

Standing firm on existing timeframes is especially important because experience in the Southeast shows that utilities have consistently taken advantage of maximum timeframes in the rule and agencies have often gone along with utilities' requests. Utilities will ask for the maximum timeframes—currently December 31, 2023—whether they need it or not. For example:

- In South Carolina, Dominion Energy South Carolina (then SCE&G) requested that SC DHEC incorporate the outer compliance deadline of December 31, 2023 into its NPDES permit for Williams Station; the permit as issued required the plant to either comply with the rule by November 1, 2018 or, if they submitted a study outlining treatment options and compliance schedules, by December 31, 2023.[75] In February 2018, after EPA postponed the November 1, 2018 deadline under the rule until November 1, 2020, the utility requested a modification to its permit to incorporate the later date.[76]
- The Alabama permitting authority is finally issuing a new permit for Alabama Power's Gaston facility eight years after the last permit expired.[77] However, the utility requested and the agency acquiesced to an extended ELG compliance deadline of December 31, 2023.[78] Alabama Power has been discharging FGD wastewater for years without limit. There is no reason for the permit to delay compliance with the ELGs to the latest possible date.
- In February 2017, EPD published notice of an updated draft NPDES permit for Georgia Power's Plant Hammond, a 1950s-era coal plant that sits on the Coosa River several miles upstream of the Georgia-Alabama border. Although Hammond has since been decommissioned, the draft NPDES permit sought to grant Georgia Power the maximum time allowable to achieve compliance with the ELG Rule (i.e. until December 31, 2023), even though the utility did not substantiate its need for so much time.
- Even at the Allen plant in North Carolina, which has been operating a FGD high residence time biological treatment system for years, Duke Energy asked NC DEQ to modify the permit to push the ELG compliance date back, for no reason other than EPA's 2017 rulemaking delayed the compliance timeframe.[79] This is not the first time Duke Energy pressed for a later deadline at Allen based on the timeframes in the rule—when the permit was initially being issued in 2018, the draft permit included a compliance date of December 31, 2023, which NC DEQ revised to November 1, 2021 after receiving

public comment on this issue.[80] This issue has also come up at other Duke Energy sites in North Carolina.[81]

Permitting delays only compound the harms that would come from rolling back this provision of the rule because the permits are slow to implement the new protections. In the Southeast, agencies routinely issue permit renewals years beyond the five-year cycle established in the Clean Water Act, further delaying protections. For example:

- In Alabama, NPDES wastewater permits have expired for five plants—some, have been expired for a decade, and all were expired before the 2015 Rule was published. Just last month, Alabama Department of Environmental Management issued a draft permit for the Gaston site, which has a permit that expired in 2012 and has been administratively continued for eight years.[82]
- In Georgia, all permits for Georgia Power's active coal-fired units at Plants Bowen, Scherer, and Wansley are expired. All of these coal plants have FGD technology that create FGD wastewater. Yet all of them continue to operate under NPDES permits issued before the scrubbers were installed and began generating waste. Thus, the NPDES permits do not address—or even contemplate—the discharge of FGD wastewater and set no limits on such discharges.[83] The permits instead only require compliance with the 1982 ELGs.
- In South Carolina, three of five permits have expired—the permit for the Cross site expired in 2006, nearly fifteen years ago. Permit renewals for these three South Carolina sites have been pending with the permitting agency for eight to ten years.[84]
- In Virginia, the wastewater permit for the Chesterfield Power Station expired in 2009 and was administratively continued for seven years, until a new permit was issued in 2016.

State	Facility	NPDES Permit No.	Expiration Date
Alabama	Alabama Power – Barry	AL0002879	**10/31/2013**
Alabama	Alabama Power – Gaston	AL0003140	**06/30/2012**
Alabama	Alabama Power – Gorgas	AL0002909	**09/05/2012**
Alabama	Alabama Power – Miller	AL0027146	**01/31/2012**
Alabama	PowerSouth – Lowman	AL0003671	**02/28/2010**
Georgia	Bowen	GA001449	**06/30/2012**
Georgia	McIntosh	GA0003883	**05/31/2004**
Georgia	Scherer		**11/30/2006**
Georgia	Wansley		**08/31/2011**
South Carolina	Dominion – Cope Station	SC0045772	12/31/2023
South Carolina	Dominion – Wateree Station	SC0002038	**12/31/2012**
South Carolina	Dominion – Williams Station	SC0003883	12/31/2021
South Carolina	Santee Cooper – Cross Generating Station	SC0037401	**08/31/2010**
South Carolina	Santee Cooper – Winyah Generating Station	SC0022471	**07/31/2011**

[75] South Carolina Generating Company A.M. Williams Station NPDES Permit No. SC0003883, Part V.9, at 37 (Nov. 16, 2016) (Attachment 24).
[76] South Carolina Dept. of Health and Envtl. Control, Public Notice No. 18-011-M (Feb. 22, 2018), https://www.scdhec.gov/sites/default/files/docs/Docs/Environment/PublicNotice/5878.pdf (Attachment 25).
[77] Alabama Department of Environmental Management, Revised Draft Permit, NPDES Permit Number AL0003140 (Dec. 6, 2019), available at http://www.adem.state.al.us/newsEvents/notices/dec19/npdes/12apc-gaston.pdf (excerpted at Attachment 26) ("Gaston Draft Permit").
[78] Id.
[79] Letter from the Southern Environmental Law Center to N.C. Department of Environmental Quality, Dec. 17, 2019 (Attachment 27); Letter from Duke Energy to NC Department of Environmental Quality, Oct. 9, 2019, available at https://edocs.deq.nc.gov/WaterResources/DocView.aspx?id=1003721&dbid=0&repo=WaterResources (Attachment 28).
[80] Compare DEQ, Draft Permit, Condition A(8), available at https://files.nc.gov/ncdeq/Water%20Quality/NPDES%20Coal%20Ash/2014%20Duke%20Energy%20Renewals%20and%20Modifications/Allen%20Draft%20WW%204979%20Permit%20041618.pdf (Attachment 29), with DEQ, Final Permit, Condition A(8) (July 13, 2018), available at https://files.nc.gov/ncdeq/Water%20Quality/NPDES%20Coal%20Ash/2014%20Duke%20Energy%20Renewals%20and%20Modifications/Allen/Allen-4979-final-permit-signed-2018.pdf (Attachment 30); letter from Southern Environmental Law Center to NC DEQ (May 14, 2018) (Attachment 31).
[81] For example, Duke Energy's Marshall site. Compare DEQ, Draft Permit, Condition A(7), available at https://files.nc.gov/ncdeq/Water%20Quality/NPDES%20Coal%20Ash/Marshall%20Draft%20Permit%20010918.pd

f, (Attachment 32), with Marshall Permit, Condition A(7) (Attachment 12); letter from Southern Environmental Law Center to NC DEQ (Feb. 13, 2018) (Attachment 33).
[82] Gaston Draft Permit, Attachment 26.
[83] See Georgia Power 2016 Integrated Resource Plan, Environmental Compliance Strategy, at p. 30, Table 2.10-1 (Jan. 2016) (listing installation dates for FGD technology at Georgia Power's coal-fired power plants) (Attachment 34).
[84] See Letter from South Carolina Environmental Law Project to SC DHEC, Sept. 23, 2019 (Attachment 35).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 148

Comment Excerpt:

XI. EPA'S PROPOSED DELAY OF COMPLIANCE DEADLINES FOR FGD WASTEWATER IS UNJUSTIFID AND UNLAWFUL.

EPA's newly proposed compliance deadlines for FGD wastewater are unjustified and unlawful. EPA is proposing to delay the compliance deadline for FGD wastewater until December 31, 2025.[568] If EPA's proposed rule is finalized in 2020, the rule will not require compliance with the FGD wastewater limitations until five years after promulgation. A five-year deadline to comply with effluent limitations is unjustified and violates the requirements of the Clean Water Act. Based on the administrative record and the Clean Water Act, EPA should require compliance with the FGD wastewater limitations no later than December 31, 2023, which would be approximately three years from issuance of the BAT determinations for FGD wastewater.

[568] 84 Fed. Reg. at 64,642.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 149

Comment Excerpt:

A. EPA's Proposed Delay of Compliance Deadlines for FGD Wastewater is Unjustified.

EPA's proposed delay of compliance deadlines for FGD wastewater is unjustified because the administrative record shows that the large majority of units can comply with the proposed rule's requirements within 2-3 years. EPA is proposing to keep the "no later than" implementation date for bottom ash transport water as December 31, 2023.[569] However, EPA is proposing to delay the "no later than" implementation date for FGD wastewater until December 31, 2025, five years after the rule will be finalized. According to EPA, "[w]hile three years may be appropriate for a facility on an individual basis, several utilities and EPC firms pointed out difficulties in retrofitting on a company-wide or industry-wide basis. Moreover, the same engineers, vendors, and construction companies are often used across facilities."[570] Therefore, the agency reasons that "more time for implementation of the proposed BAT limitations [for FGD wastewater] will help to accommodate the process changes necessitated by combining chemical precipitation and LRTR, and alleviate competition for resource."[571] However, EPA acknowledges throughout the preamble and proposed rule that most units can comply with the FGD wastewater limitations within 2-3 years.

As EPA states in the preamble:

Information in the record indicates a *typical time frame of 26 to 34 months* to raise capital, plan and design systems (including any necessary pilot testing), procure equipment, and construct and then test systems (including a commissioning period for FGD wastewater treatment systems). Many facilities have already completed initial steps of this process, having evaluated water balances and conducted pilot testing to prepare for implementing the 2015 rule.[572]

During EPA's reconsideration of the 2015 rule, the agency collected implementation timing information from vendors for FGD wastewater treatment technologies.[573] Specifically, ERG, EPA's technical support consultant, reviewed information from three vendors for low residence time reduction (LRTR) and membrane filtration installations.[574] The timing estimates for installing LRTR systems indicate a total implementation timeframe of approximately twenty-five months while the timing estimates for installing membrane filtration indicate a total implementation timeframe of no more than twenty-eight months.[575] EPA should base the compliance deadlines for FGD wastewater on the data in the administrative record rather than on expressed difficulties by some utilities.

Furthermore, in determining that "low utilization" units can comply with the effluent limitations for bottom ash transport water and FGD wastewater within two years,[576] EPA acknowledges that three years for compliance with the FGD wastewater limitations is achievable. As discussed in Section X.D – Low Utilization, EPA is proposing to implement tiered limitations for the agency's proposed subcategory for "low utilization" boilers, which EPA defines as a unit that does not exceed a two-year average net generation of 876,000 MWh.[577] Specifically, if an operator reported that it exceeded the two-year average net generation for a unit, it would have two years before discharges of FGD wastewater would be subject to the rule's effluent limitations.[578] As EPA explains, the two-year timeframe for compliance with the FGD wastewater limitations is "consistent with the engineering documents provided to the EPA for the installation of the appropriate technologies."[579] Furthermore, the two-year timeframe for compliance would "ensure a *timely transition* to more stringent limitations as soon as the reason for the less stringent limitations (disproportionate cost) is gone."[580] By proposing compliance deadlines of five years, EPA contradicts its own determinations elsewhere in the proposed rule and goes against the information in the administrative record.

Although EPA mentions that the same engineers, vendors, and construction companies are often used across facilities, the administrative record shows that there is actually a wide variety of vendors as well FGD wastewater treatment technologies that alleviates any vendor bottleneck that the agency is stating as the reason for the delay of compliance deadlines. As EPA identified in the Technical Development Document for the proposed rule, there are several different types of FGD wastewater treatment technologies that have been developed and installed or tested at power plants.[581] The options of treatment technologies include high residence time reduction (HRTR) and LRTR biological treatments, zero-valent iron, membrane filtration, thermal treatment and solidification as well as other pilot-scale tested alternative technologies.[582] Additionally, EPA received information and data regarding FGD wastewater treatment technologies from several different vendors.[583] Overall, the information and data EPA received and reviewed regarding implementation timing and the different types of treatment technologies from various vendors do not support a five year timeframe for compliance with FGD wastewater limitations.

[569] Id. at 64,641.
[570] Id. at 64,642.
[571] Id.
[572] Id.
[573] See ERG, FGD and Bottom Ash Implementation Timing memo, Docket ID No. EPA-HQ-OW-2009-0819-8191.
[574] Id. at 2-3; see also Frontier Water Systems, Project Timeline, Docket ID No. EPA-HQ-OW-2009-0819-8177; Envirogen, Selenium Projects Timeline, Docket ID No. EPA-HQ-OW-2009-0819-8178; New Logic Research, Implementation timelines for Membranes, Docket ID No. EPA-HQ-OW-2009-0819-8179.
[575] ERG memo at 2-3; see also Section VI – Zero Discharge FGD.
[576] 84 Fed. Reg. at 64,666.
[577] Id.
[578] Id.
[579] Id.
[580] Id.
[581] EPA, Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Docket ID No. EPA-HQ-OW-2009-0819-8211 (Nov. 2019) ("2019 Proposed TDD"), 4-1.
[582] Id. at 4-1, 4-2.
[583] See Final BKT Engineering Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7316; Final Envirogen Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7324; Final Oasys Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7334; Final FTS Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-8159; Final KLeeNwater Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7617; Saltworks Vendor Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7328; Final Heartland Vendor Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7619; New Logic Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7623; Carmeuse Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7624; Final Novinda Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7629; Final SUEZ Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7630; Final Aquatech Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7631; Final GreenBlu Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7632; Final Purestream Meeting #1 Notes, Docket ID No. EPA-HQ-OW-2009-0819-7640; Final Evoqua Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7641; Final Mitsubishi Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7642; Final Veolia Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-7643; Final Montrose Meeting Notes, Docket ID No. EPA-HQ-OW-2009-0819-8089 & Docket ID No. EPA-HQ-OW-2009-0819-8090.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 153

Comment Excerpt:

B. EPA's Proposed Delay of Compliance Deadlines for FGD Wastewater is Unlawful.

EPA's proposed five-year timeframe for compliance with FGD wastewater limitations is unlawful because the proposed provision violates the effluent limitation requirements of the Clean Water Act.[584] EPA is proposing to delay the "no later than" implementation date for FGD wastewater until December 31, 2025, approximately five years after the FGD wastewater limitations are to be finalized.[585] By extending these compliance deadlines, EPA is violating the Clean Water Act provision that requires compliance with the ELGs no later than three years after the limitations are promulgated.[586] [587]

EPA will no doubt respond to this comment by claiming that the three-year deadline for ELG compliance only applies to the first set of BAT limitations for toxic pollutants from an industry. That argument relies on the fact that the compliance deadline provision in Section 301(b)(2)(C) of the Act also states that compliance must be achieved "in no case later than March 31, 1989," an interpretation accepted by the U.S. Court of Appeals for the Fifth Circuit in litigation over EPA's rule delaying the compliance dates of the 2015 ELGs.[588] However, that decision was legally erroneous and, even it were correctly decided on the law, does not properly apply to the facts of the present regulation.

The plain text of Section 301(b)(2)(C) specifies that compliance must be achieved no later than three years following the promulgation of toxic pollutant BAT limitations, and there is nothing ambiguous about that language. That the same section also contains a provision – establishing March 1989 as the presumptive outside date for initial limitations – does not render the otherwise-applicable three-year language (or, for that matter, the otherwise-applicable "as expeditiously as practicable" language) unclear. To the contrary, it underscores that Congress viewed compliance with BAT limitations on toxic pollutants as an urgent priority, to be met quickly after such limitations were promulgated. Moreover, Section 301(d) reinforces this approach, demanding that effluent limitations be reviewed and updated as appropriate every five years, "pursuant to the procedure established under" Section 301(b)(2);[589] this provision reveals Congressional intent to continually and promptly move industries toward better pollution controls and, by incorporating the procedures of subsection (b), directs EPA to follow the compliance deadlines for BAT limitations on toxic discharges in subsection (b)(2)(C), minus the outdated reference to March 1989.

Even if one were to accept – which we do not – the interpretation that the three-year deadline for BAT limitations on toxic discharges only apply to the initial promulgation of such limitations, the limitations established by this rulemaking for FGD wastewater qualify as such initial limits. In the 1982 steam electric ELG rule, EPA expressly "reserve[ed] effluent limitations for four types of wastewaters for future rulemaking," including ""[f]lue gas desulfurization waters," not setting any effluent limitations at all specific to those wastestreams.[590]

The Clean Water Act's requirement that compliance with BAT limits be achieved within three years is consistent with its overall goal to eliminate all discharges of pollution into navigable waters[591] and its framework for achieving that goal. The Act requires that EPA set effluent limits based on BAT for pollutants including toxic metals.[592] To facilitate the adoption and revision of effluent limitations, the Act also requires that EPA develop and publish ELGs that characterize the effluent discharges from a given industry, identify the level of pollution control that is possible in light of available technologies, and specify the relevant factors for determining what constitutes BAT.[593] To ensure that governing regulations reflect advances in control technology, the Clean Water Act requires EPA to review and, if appropriate, revise these effluent limitations and underlying ELGs at regular intervals.[594] Section 301(d) of the Clean Water Act requires that all effluent limitations "*shall* be reviewed at least every five years, and, if appropriate, revised."[595] Similarly, with respect to ELGs, Section 304(b) of the Clean Water Act requires that "the Administrator *shall* . . . publish . . . regulations, providing guidelines for effluent limitations, and, at least annually thereafter, revise, if appropriate, such regulations."[596]

EPA is planning to finalize the FGD wastewater limitations by December 31, 2020. Three years from issuance of the BAT determinations would be no later than December 31, 2023. A three-year timeframe for compliance with FGD wastewater limitations is consistent with the congressional goals of the Clean Water Act. Congress' goal in enacting the Clean Water Act was to produce progressively cleaner waters – and ultimately eliminate all pollution – through the ratcheting down of effluent limits over time as technology advances.[597] Mandatory revisions to standards would be meaningless without mandatory deadlines for compliance with the revised standards. Furthermore, as EPA has acknowledged, the agency has previously required no longer than a three-year timeframe for compliance with ELGs.[598]

In summary, EPA should not delay the compliance deadlines for FGD wastewater and, instead, should require compliance with the effluent limitations for FGD wastewater by no later than December 31, 2023. This three-year timeframe for compliance would be in line with the data and information in the administrative record and in accordance with the requirements of the Clean Water Act.

[584] Several of the commenters challenged EPA's 2017 rule that postponed the compliance deadlines for bottom transport water and FGD wastewater established in the 2015 ELG rule on the basis, amongst other reasons, that the Clean Water Act required compliance with ELGs within three years of promulgation. The United States Court of Appeals for the Fifth Circuit denied the commenters' petition for review in August 2019. See *Clean Water Action v. EPA,* 936 F.3d 308 (5th Cir. 2019).

[585] 84 Fed. Reg. at 64,642.

[586] 33 U.S.C. § 1311(b)(2)(C) (requiring "compliance with [BAT] effluent limitations . . . as expeditiously as practicable but in no case later than three years after the date such limitations are promulgated . . . , and in no case later than March 31, 1989"). Subsections (D) and (F) are also applicable and include identical language requiring that compliance with effluent limitations be achieved within three years after promulgation.

[587] Congress initially set a March 31, 1989 deadline for compliance with BAT effluent limitations, Pub. L. No. 100–4, 101 Stat 7 (1987), with the intention that EPA would promulgate ELGs setting forth those address issues involving compliance with BAT limits through enforcement discretion. See 33 U.S.C. § 1319(a)(5)(A) ("Any [enforcement] order issued . . . shall specify a time for compliance . . . not to exceed a time the Administrator determines to be reasonable in the case of a violation of a final deadline, taking into account the seriousness of the violation and any good faith efforts to comply with applicable requirements."); H.R. Conf. Rep. No. 1004, 99th Cong., 2d Sess. 115 (1986) ("If dischargers in an entire category are unable to meet the March 31, 1989, deadline provided in the conference substitute as a result of the Administrator's failure to promulgate effluent limitations in sufficient time to allow for compliance by such date, non-compliance resulting from the Administrator's delay can be dealt with under EPA's current post-1984 deadline enforcement policy."). Based on this legislative history, courts have held that EPA lacks discretion to extend compliance deadlines for BAT limits beyond what the statute requires. See *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 242, clarified on reh'g, 885 F.2d 253 (5th Cir. 1989); see also *Rybachek v. EPA*, 904 F.2d 1276, 1300 (9th Cir. 1990).

[588] See *Clean Water Action*, 936 F.3d at 316-17 accepting EPA argument that deadlines only apply to initial

promulgation).
[589] 33 U.S.C. § 1311(d).
[590] 47 Fed. Reg. 52,290, 52,291 (Nov. 19, 1982).
[591] 33 U.S.C. § 1251(a)(1).
[592] See id. §§ 1311(b)(2)(A)-(F), 1314(a)(4).
[593] Id. § 1314(b).
[594] See id. §§ 1311(d), 1314(b).
[595] Id. § 1311(d) (emphasis added).
[596] Id. § 1314(b) (emphasis added).
[597] Id. §§ 1251(a)(1), (2), (6).
[598] EPA "has used the reference to three years in the provisions to allow three years to come into compliance for ELGs after 1989." EPA, Postponement of ELG Compliance Deadlines Comment Response Document, Docket ID No. EPA-HQ-OW-2009-0819-7088 (Sept. 2017), at pdf p. 9.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 155

Comment Excerpt:

XII. EPA SHOULD MAKE CLEAR IN ANY FINAL RULE THAT COMPLIANCE MUST BE ACHIEVED AS SOON AS POSSIBLE.

The 2015 ELG Rule provided that plants must comply with BAT limitations set forth in the rule "as soon as possible after November 1, 2018, and no later than December 31, 2023." In the 2019 Proposal, EPA has proposed that plants must comply with any new BAT limitations "as soon as possible on or after November 1, 2020" and "no later than" December 31, 2023 for bottom ash transport water or December 31, 2025 for FGD wastewater.[599]

Both the 2015 ELG Rule and 2019 Proposal require state permitting authorities to set deadlines for achieving compliance with BAT limitations based on consideration of plant-specific factors.[600] Those factors, which have been in place since the 2015 ELG Rule and remain the same in the 2019 Proposal, are: (a) time to expeditiously plan, design, procure, and install equipment; (b) changes the facility is undertaking to comply with regulations of greenhouse gases and coal combustion residuals; (c) optimization periods for pollution-control technology installed for FGD; (d) and other factors as appropriate.[601]

Although the 2015 ELG Rule made clear that state permitting authorities must use plant-specific information when considering these factors, EPA acknowledges in its 2019 Proposal that permit writers have not always determined a plant's earliest possible compliance date based on the requisite plant-specific information.[602] Commenters support EPA's proposal to "clarify that the discharger must provide *relevant, site-specific information*" to permitting authorities in order to seek a compliance date later than November 1, 2020.[603] EPA's statement simply reiterates the requirement set forth in the 2015 ELG Rule.[604] We agree with EPA that permitting authorities must "provide a well-documented justification of how [they] determined the 'as soon as possible' date in the fact sheet or administrative record for the permit" and that "[i]f the permitting authority determines a date later than November 1, 2020, the justification should explain why allowing additional time to meet the proposed limitations is appropriate, and why the discharger cannot meet the effluent limitations as of November 1, 2020."[605]

[599] 84 Fed. Reg. at 64,664.
[600] Id. at 64,624, 64,664-65.
[601] Id. at 64,664-65.
[602] See id. at 64,665 ("Environmental groups informed the EPA that facilities had filed permit applications for, and states had granted, delayed applicability dates based on information about a facility other than the one being permitted. *This was not the intent of the 2015 rule* . . . .") (emphasis added).
[603] 84 Fed. Reg. at 64,665 (emphasis added).
[604] See 80 Fed. Reg. at 67,883 (indicating that permitting authorities must determine a plant's compliance deadline based on information from the specific plant at issue. For example, EPA explains that with respect to the first factor, the permitting authority "should evaluate what operational changes are expected at *the* plant to meet the new BAT limitations." (emphasis added)). It is clear in the 2015 ELG Rule that EPA intended permitting authorities to determine a plant's compliance deadline based on information from *that particular plant* and not from *any* plant or the industry as a whole.
[605] 84 Fed. Reg. at 64,665.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 156

Comment Excerpt:

Commenters also agree with EPA's statement in the 2019 Proposal that in setting plant-specific compliance dates, permitting authorities must "determine the *earliest possible date* that the facility can meet the limitations . . . and apply the proposed limitations as of that date." [606] Here too, EPA's statement simply reiterates the requirement that EPA set forth in its 2015 ELG Rule that "the permitting authority should determine the earliest possible date that the plant can meet the limitations."[607] In both the 2015 ELG Rule and 2019 Proposal, EPA uses the phrase "earliest possible date" interchangeably with the requirement that dischargers achieve compliance "as soon as possible." EPA should make clear in any final rule that the two phrases have the same meaning with respect to compliance deadlines and impose the same timing requirement that was established in the 2015 ELG Rule.

Nevertheless, despite this clear requirement in the 2015 ELG Rule, state permitting authorities have failed to comply with their obligations to determine appropriate "as soon as possible" compliance deadlines for facilities.[608] For example: Pennsylvania's Department of Environmental Protection has accepted cursory and non-plant-specific rationales for 2023 compliance dates at multiple plants;[609] Indiana's Department of Environmental Management has set a 2018 compliance date for the Merom plant subject to broad reopener provisions that render that compliance date mostly meaningless;[610] Texas's Commission on Environmental Quality has issued a final permit for the Sandow plant that does not impose an ELG compliance date but instead allows the permittee one year to propose a compliance date and submit supporting materials;[611] and both Kentucky's Energy and Environment Cabinet and Ohio's Environmental Protection Agency have postponed plants' compliance with BAT limitations to 2023 based on nothing more than anticipation of the 2019 Proposal.[612] These examples reveal that state permitting authorities implementing the 2015 ELG Rule frequently defaulted to 2023 compliance dates in violation of their obligation to determine plants' earliest possible compliance dates, and have based their compliance determinations on generic industry information—or in the case of Kentucky and Ohio, on no information—rather than on plant-specific information as the ELG Rule requires.

The requirement that permitting authorities consider only plant-specific information in determining a plant's compliance deadline is integral to the requirement that plants achieve compliance as soon as possible. Unless a permitting authority uses site-specific information in considering the compliance-timing factors, the factors themselves are wholly irrelevant to the question of the earliest possible date by which a plant can achieve compliance with BAT.
For example, the second factor instructs permitting authorities to consider "changes being made or planned at the plant" in response to new regulations. But changes made at the Merom plant have no bearing on when the Sandow plant can achieve compliance with BAT limitations. By using generic industry information to determine a plant's compliance date, permitting authorities eviscerate the requirement that a plant achieve compliance with the rule as soon as it is possible for the plant to do so.

Because these problems are likely to persist without EPA action, EPA should strengthen language in any final rule that makes clear that November 1, 2018 is the default compliance date for BAT limitations established in the 2015 ELG Rule and November 1, 2020 is the default compliance date for any new BAT limitations established in the current rulemaking. EPA also should strengthen its oversight of state-permitting authorities' compliance date decisions to ensure that they are consistent with the requirement that plants achieve compliance as early as possible based on plant-specific information.

[606] Id. at 64,664-65 (emphasis added).
[607] 80 Fed. Reg. at 67,883.
[608] See EPA-HQ-OW-2009-0819-7751, ERG Memorandum to Ron Jordan, EPA from Sara Bossenbroek, ERG, Notes from Meeting with Earthjustice et al., at 3 (Aug. 23, 2019).
[609] See, e.g., Sierra Club, Comments on Draft NPDES Permit No. PA0001627 for Cheswick Generating Station (Feb. 12, 2018) (attached); Sierra Club, Comments on Draft NPDES Permit No. PA0027481 for Bruce Mansfield Plant (Sept. 10, 2018) (attached); Sierra Club, Comments on Draft NPDES Permit No. PA0005037 for Homer City Generating Station (Sept. 4, 2018) (attached); Sierra Club et. al., Comments on Draft NPDES Permit No. PA0002062 for Keystone Generating Station (Mar. 29, 2018) (attached).
[610] IDEM, Final Modification: Permit No. IN0050296 Hoosier Energy, Merom Generating Station, Sullivan, Indiana (Aug. 5, 2016) (attached).
[611] TCEQ, Permit to Discharge Wastes, TPDES Permit No. WQ0000395000, Alcoa Inc. (Oct. 26, 2016) (attached).
[612] See, e.g., Kentucky Division of Water, KPDES No. KY0041971, Trimble County Generating Station (Jan. 19, 2018) (attached); Ohio EPA, Fact Sheet, NPDES Permit No. 0IB00009*WD (2018) (attached).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 158

Comment Excerpt:

In addition, EPA should clarify existing language about the factors that permitting authorities must consider in determining plants' compliance dates. Specifically, EPA should make clear in any final rule that facilities must "plan, design, procure, and install" pollution-control technology concurrently to the greatest extent possible in order to reduce the time needed to achieve compliance. Commenters agree with EPA's statement in the 2019 Proposal that:

Regardless of when a facility's NPDES permit is ready for renewal, the EPA recommends that each facility immediately begin evaluating how it intends to comply with the requirements of any final rule. In cases where significant changes in operation are appropriate, the EPA recommends that the facility discuss such changes with its permitting authority and evaluate appropriate steps and a timeline for the changes as soon as a final rule is issued, even prior to the permit renewal process.[613]

In furtherance of this requirement, EPA also should require state permitting authorities to consider the amount of time that has elapsed between promulgation of any final rule and a plant's permit renewal date in determining a plant's earliest possible compliance date. For example, if a permit is not renewed until 2023, that permittee should be required to come into compliance with the final rule immediately upon receiving its renewed permit. This factor would incentivize permitting authorities and plants to begin planning for compliance before the permit renewal process, which is consistent with the above-quoted language from the 2019 Proposal and with the requirement that plants achieve compliance "as soon as possible."

[613] 84 Fed. Reg. at 64,664. EPA also made this statement in the 2015 ELG Rule. See 80 Fed. Reg. at 67,882-83.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 19

Comment Excerpt:

1.7 BATW Zero-Discharge Implementation Timelines

Finally, EPA proposes to maintain the "no later than" compliance date of December 31, 2023 for BATW. This is based on EPA's finding that a typical compliance time frame for implementing zero discharge for BATW is 15-23 months.[47] EPA provides two documents to support this timeline: one from a vendor, United Conveyor Corporation (UCC)[48] and another purportedly from industry.[49] While none of the underlying details from either of these sources are available, it is instructive to note that the time frames from contract award to when a system might be fully operational is, at most 30 months and can be as low as 15 months per Mr. Moskal, the industry source.[50] The "average" similar time period provided by UCC is 26 months with shorter time frames for the lower portions of the ranges indicated.

Considering that EPA is dealing with BAT (i.e., setting the standard based on the best performing plants), and based on the above, I concur with EPA regarding that a compliance time frame of 15-23 months is achievable.

47 84 Fed. Reg. at 64,641.
48 Email Correspondence of Kevin McDonough, UCC, Phillip Flanders, EPA, and Elizabeth Gentile, ERG, Re: Implementation Timelines for Bottom Ash Transport Water (Oct. 2019) (EPA-HQ-OW-2009-0819-8181).
49 Email Correspondence of Tom Moskal and Phillip Flanders, EPA, Re: Time to Implement Bottom Ash Handling Systems (Aug. 2019) (EPA-HQ-OW-2009-0819-8180).
50 See Bottom Ash Handling System Retrofit Projects (EPA-HQ-OW-2009-0819-8180).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 1

Comment Excerpt:

APPA believes that the timeline for facilities to meet the PSES, which is no later than three years after the effective date of any final rule, is insufficient for several reasons. Because units complying with BAT for FGD wastewater have until 2025 to comply, there should be some form of parity between these two standards.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 3

Comment Excerpt:

In the 2015 Rule, the earliest compliance date for new, more stringent BAT effluent limitations and PSES for FGD wastewater and BA transport water was no later than November 1, 2018. In the 2017 Postponement Rule, EPA amended the date to no later than November 1, 2020. In this Proposed Rule, EPA is suggesting that the earliest compliance date for BA transport water will remain no later than November 1, 2020. To ensure compliance and for consistency with the Coal Combustion Residuals (CCR) rule, EPA should set the deadline for compliance with BAT limitations for BA transport water as no later than December 31, 2025.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 7

Comment Excerpt:

III. EPA SHOULD DELAY THE PROMULGATION OF THE PSES

EPA is authorized under section 307(b) of the CWA, 33 U.S. C. § 1317(b), to promulgate pretreatment standards for discharges of pollutants to publicly-owned treatment works (POTWs). Pretreatment standards for existing sources (PSES) are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of a POTW. These standards are technology-based and are analogous to Best Practicable Control Technology Currently Available (BPT) and BAT effluent limitations guidelines. Therefore, EPA considers the same factors in promulgating PSES as it considers when it considers promulgating BPT and BAT.

The 2015 Rule established PSES for FGD wastewater and BA transport water with an earliest compliance deadline of November 1, 2018. However, in 2017, after notice and comment, EPA finalized a rule that, among other things, postponed that earliest compliance date until November 1, 2020.[6] In this Proposed Rule, EPA is proposing, among other things, new timelines for compliance with the final BAT effluent limitations for BA transport water, FGD wastewater, and PSES for both BA transport water and FGD wastewater. EPA is proposing that BAT effluent limitations for BA transport water apply as soon as possible beginning November 1, 2020, but no later than December 31, 2023, and no later than December 31, 2025 for FGD wastewater. EPA is also proposing that, because existing indirect dischargers many need time to achieve the final standards, in part to avoid forced outages, facilities must meet the PSES for BA transport water and FGD wastewater no later than three years after the effective date of any final rule. Based on EPA's projections this will be sometime in the summer of 2023.[7]

APPA believes that there should be some parity between the PSES compliance timeline and the compliance timeline for the BAT effluent limitations for both BA transport water and FGD wastewater. EPA notes that section 307(b)(1) of the CWA (33 U.S.C. §1317(b)(1)) requires that the compliance timeline for PSES shall not exceed three years from the date of promulgation, so their hands are basically tied. However, given that three years may be insufficient due to a number of factors including: resource constraints with equipment suppliers and potential onerous permit approvals, APPA feels that an alternative is necessary. APPA
suggests that, to accommodate these facilities and the potential hurdles indirect dischargers may have with the proposed compliance timeline, and to have some form of parity with the BAT limitations for BA transport water and FGD wastewater, EPA should delay promulgation of the PSES limits until at least December 31, 2020 but preferably until December 31, 2022, giving these facilities until either December 31, 2023 or December 31, 2025 to comply. By doing so, the compliance timeline will comply with the statutory mandate of "not to exceed three years from the date of promulgation" and dovetail with the 2025 compliance timelines for the BAT effluent limitations for BA transport water and FGD wastewater.

6 Id.
7 EPA anticipates finalizing this proposed rule during the summer of 2020.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 11

Comment Excerpt:

VI. EPA SHOULD AMEND THE BA TRANSPORT WATER APPLICABILITY DATES

In this Proposed Rule, EPA seeks to amend certain applicability dates as well as retain some of the applicability dates from its 2017 Postponement Rule.[14] One such compliance timeline is for the BAT limitation for BA transport water. In the 2015 Rule, the earliest compliance date for new, more stringent BAT effluent limitations and PSES for FGD wastewater and BA transport water was no later than November 1, 2018. In the 2017 Postponement Rule, EPA amended the date to no later than November 1, 2020. In this Proposed Rule, EPA is suggesting that the earliest compliance date for BA transport water will remain no later than November 1, 2020 to December 31, 2023.

A. EPA Should Set the Deadline for Compliance with BAT Limitations for BA Transport Water As No Later Than December 31, 2025, In Order to Harmonize With The FGD Compliance Date

As stated above, EPA is proposing to retain the earliest compliance date of no later than November 1, 2020 for the BAT limitations for BA transport water, as amended by the 2017 Postponement Rule.[15] EPA's rationale is that after considering many factors, including changes being made at facilities due to other Agency rules such as the Coal Combustion Residuals (CCR) Rule, the time frame would allow facilities to raise capital, plan and design systems, procure equipment, and then construct and test systems. [16]

Unlike the 2015 ELG rule however, the Proposed Rule's applicability dates for BA transport water and FGD wastewater are no longer in harmony. Instead, the latest BA transport water deadline is two years earlier than the latest FGD wastewater deadline. APPA encourages EPA to establish a BA transport water applicability date of no later than December 31, 2025, both to provide the time necessary to make and implement reasoned decisions as to BA transport water and to harmonize the schedules for BA transport water and FGD wastewater treatment.

The Proposed Rule suggests "15-23 months is typical timeframe to raise capital, plan and design systems, procure equipment and construct a dry handling or closed-loop, or high rate recycle BA system."17 It is unclear from EPA's supporting material that this timeframe captures all the steps some facilities must take. For example, public power utilities are also entities of state and local government must often work through their governing boards and or city councils to gain approval for capital projects. This approval process may require obtaining financing or issuing debt/bonds to pay for the projects, and coordinating with contractors, labor unions, and crane operators, along with obtaining any required permits. The timeframe to secure financing would be in addition to contracting, engineering, equipment installation, and testing schedules. The governing board approval process can take anywhere from 6-12 months. Further, as a threshold matter, the suggested timeframe for BA transport water compliance does not account for the deliberation a facility must undertake regarding whether to retrofit, retire, or repower the affected unit. This decision can only be made once a final rule is issued.

The Association believes the proposed December 31, 2023 applicability date is too short because it fails to account for important factors that may require additional time.

To ensure compliance, and for consistency, EPA should set the deadline for compliance with BAT limitations for BA transport water as no later than December 31, 2025, to match the latest FGD wastewater applicability date. Harmonizing the BA transport water and FGD deadlines would allow for facilities to reuse BA transport water as make-up water for FGD scrubbers. The 2015 rule allowed, and the current Proposal continues to allow, facilities to use BA transport water as make-up to the FGD scrubber.[18] But facilities that choose to do so must, under both the 2015 rule and EPA's current Proposed Rule, meet the limits specified in § 423.13(g)(1)(i) for FGD scrubber blowdown. As the Proposal recognizes, waste treatment facilities for FGD blowdown will not be available for many facilities until December 31, 2025— a full two years later than the latest applicability date EPA has proposed for BA transport water. Thus, to allow facilities capable of using the option of reusing BA transport water in their scrubber, EPA must extend the latest compliance deadline for BA transport water to December 31, 2025.

14 See footnote 5, supra.
15 See footnote 5, supra.
16 EPA published the Disposal of Coal Combustion Residuals from Electric Utilities final rule in 2015 (2015 CCR Rule), 80 Fed. Reg. 21301 (April 17, 2015). In 2016, based on partial vacatur of the U.S. Court of Appeals for the D.C. Circuit, a final rule extending some of the compliance deadlines was published, 81 Fed. Reg. 51802 (Aug. 5, 2016). In March 2018, EPA finalized Phase One, Part One of its revisions to the 2015 CCR Rule, 83 Fed. Reg. 36436 (July 30, 2018). EPA has since published additional proposed rules, 83 Fed. Reg. 11584 (March 15, 2018); 84 Fed. Reg. 40353 (Aug. 14, 2019); and 84 Fed. Reg. 65941 (Dec. 2, 2019).
17 84 Fed. Reg. at 64,641 n.74.
18 See Proposed § 423.13(k)(1)(i), 84 Fed. Reg. at 64,674; § 423.13(k)(1)(1).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 12

Comment Excerpt:

B. The Default Deadline of November 1, 2020 is Unnecessary

In the 2015 ELG rule, EPA's decision to set a "default" applicability date was reasonable because EPA had information in the record suggesting that at least some facilities affected by the rule could comply with the three-year compliance period anticipated by the deadline. In addition, the structure of the applicability provision allowed permittees time to seek an alternative date. The November 1, 2020, deadline is simply an artifact of the Postponement Rule.[19]
The November 1, 2020 deadline was based on the amount of time needed to complete further rulemaking.[20] Therefore, the November 1, 2020 default deadline should be deleted or changed to

one that can be met by the majority of facilities affected by the rule while allowing those that cannot meet the deadline a fair chance to seek an alternative schedule.

Given the time frames in question, and the fact that these are nationally applicable, categorical requirements, it would be entirely reasonable and consistent with the statute and past Agency practice for EPA to establish a single, latest deadline of December 31, 2025 for BA transport water and FGD wastewater and to apply that applicability deadline to all facilities in the category. Facilities that already possess the technology needed to comply will continue to use that technology, as dictated by EPA's NPDES rule prohibiting the bypass of treatment technologies except under limited circumstances. [21]

Setting a single deadline would avoid the procedural problems inherent in setting a default date without also establishing procedural requirements requiring permit writers to act promptly and, in some cases, outside the standard permit renewal process on requests for alternative deadlines. Permittees whose permits were not slated for imminent renewal reported that permit writers often were reluctant to make decisions on requests for alternative schedules, for fear of public criticism or simply because of other agency priorities. But certainty regarding the deadline for compliance is an absolute necessity for technology planning and financing. Setting a single, adequate deadline for all facilities would solve this problem, without adding burdens to state permit writers.

If EPA decides to retain the proposed approach of setting an initial "as soon as possible" deadline, as well as an outside deadline, it should take the following steps. First, it must select a deadline that gives facilities a fair chance either to comply or seek a later deadline. Second, it must provide clear instructions to the states as to when and how decisions on alternative deadlines should be made, especially where the permit is not up for renewal and no permit modification is otherwise sought.

19 82 Fed. Reg. at 43,494.
20 Id. at 43,498.
21 40 C.F.R. § 122.41(m).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 13

Comment Excerpt:

C. EPA Needs to Consider Additional Factors in Setting the Compliance Date for BA Transport Water.

In this Proposed Rule, as in the 2015 Rule, EPA considered the magnitude and complexity of process changes, new equipment installations that would be required to meet the proposed requirements, and the availability of the technologies for FGD wastewater and BA transport water. EPA states that it selected the compliance timeframes to ensure that facilities would have time to raise needed capital, plan and design systems, procure equipment, and construct and test systems. EPA also states that it considered facility changes that would need to be made due to compliance with other Agency rules, such as the CCR Rule.

However, EPA has not considered other important factors impacting a facility's ability to meet the compliance deadline in the Propose Rule. For instance, EPA should consider planned outage schedules, lead times in acquiring equipment, time for obtaining the appropriate permits from local, state, or federal agencies, tie-in, commissioning, and the inevitable weather-related construction delays. By statute, EPA must consider (a) time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final rule; (b) changes being made or planned at the facility in response to greenhouse gas regulations for new or existing fossil fuel-fired power facilities under the Clean Air Act, as well as regulations for the disposal of coal combustion residuals under subtitle D of the Resource Conservation and Recovery Act; (c) for FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment; and (d) other factors as appropriate.[23] If EPA is to meaningfully consider these additional factors, a compliance timeline of November 1, 2020 is infeasible. For this reason, as well as for greater compatibility with the proposed deadlines in the Proposed CCR Rule, EPA should set the date for compliance with the BAT limitations for BA transport water as December 31, 2025.

23 Fed. Reg. Vol. 84, No. 226, p. 64641, fn 72 (citing 40 CFR § 423.11(t)).

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 21

Comment Excerpt:

E. APPA Members Need Time to Evaluate Implications of Final Rule

The time required to analyze the final rule and gather data in order to make informed decisions about whether to retrofit, retire, or repower a unit could take approximately two years. If the decisions to repower is made permittee will need approximately 6 years to complete new transmission and/or generation projects. These considerations include business decisions related to financing, facility changes required by other rules, and other factors that bear on the decision to retrofit or retire units. Beyond what can be completed during the ELG rule reconsideration, permittees will have a myriad of task associated with picking and planning the retrofit of the appropriate technology. Such tasks might include:

- Gather initial information on the candidate technologies for each affected wastestream;
- Evaluate if all wastestreams are correctly mapped on a diagram;
- Develop a final list of technologies and costs;
- Prepare a request for proposal for each technology;
- Develop conceptual designs, for the unit(s) being retrofitted;

- Determine permitting requirements, develop permitting timelines, obtain or modify permit;
- Make the technology selection;
- Coordinate existing equipment tie-ins with planned unit outages; and
- Evaluate and consider changes to facilitates to comply with other regulations, like the CWA§ 316(b) Rule, the CCR rule, and the Affordable Clean Energy rule.

Public power utilities will also have to determine how the project will be financed and conduct economic assessments. Public power utilities as entities of state and local government are governed by city councils and elected or appointed boards. Customers have a direct input in utility decisions, including rates and its selection of generation technology. Public power utilities use municipal bonds to finance investments in power generation transmission, distribution, reliability, demand control, efficiency, wastewater, and emission control projects. Municipal bonds are unique in that they have maturities nearly twice as long as corporate bonds and are generally issued as a series with varying maturities, rather than a single maturity. A public power utility is limited in how they raise capital. As not-for-profit entities of local government governed by local city councils or elected or appointed boards, public power utilities will have to undergo varying steps to obtain approval to retrofit BA transport water and FGD wastewater technologies. The utilities' governing bodies must meet to determine if the project is necessary and review and approve staff plans to implement the option(s) selected. The city councils or boards must meet to pass a resolution to finance the project, and then a bond counsel is assembled. The bond process could take six months to one year, followed by an additional year to decide on the bond product. Then there is a three- to six-month process to raise electricity rates to recover the capital costs. The process public power utilities must undergo to raise capital should be factored into the timeframe to retrofit or repower. In this context EPA should allow permittees at least eight years after the final rule's effective date to retrofit or repower.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 24

Comment Excerpt:

APPA requests that EPA finalize this rule a quickly as possible, consistent with all administrative procedures. The certainty that a final ELG Rule would provide is extremely beneficial, allowing public power utilities to plan how their facilities may operate in the future.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)

Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 28

Comment Excerpt:

EPA also proposes to modify the definition of "as soon as possible" to require that the information provided by the permittee be "site-specific." EPA says that this change was motivated by information it received suggesting that facilities had filed permit applications based on information for facilities other than the one being permitted, which the Agency says was not the intent of the 2015 rule.[22] But EPA does not point to anything in the 2015 rule that precludes the use of other information, nor does EPA explain why relevant non-site-specific information (for instance, information on experience at other similar facilities or studies prepared by reputable engineering experts based on a range of experience) should not also be considered.

22 84 Fed. Reg. at 64,665.

34 <u>Regulatory Implementation – VIP</u>

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 28

Comment Excerpt:

E. Membrane Filtration and Paste Encapsulation are Appropriate as a VIP Option.

The 2015 ELG rule established a VIP that placed limits on mercury, arsenic, selenium, and TDS in FGD wastewater based on thermal evaporation technology.[51] Facilities participating in the VIP would have had until December 31, 2023 to comply with the new limits.[52] EPA now proposes to revise the applicability date for the VIP limits to December 31, 2028, and revise the limits set in the 2015 Rule using membrane filtration as the technology basis.[53]

Southern Company agrees with EPA that membrane filtration and paste encapsulation are appropriate as a VIP option, but EPA should clarify two important aspects for the option:

1. Any technology that meets the VIP limits should qualify for this option. The VIP option does not require a specific technology, such as EPA's model technology (membrane filtration). Other technologies that could potentially meet the proposed VIP limits on a site-specific basis are spray dryers and vapor compression evaporation.
2. The applicability date for any facility that opts into the VIP should be at least eight years from the effective date of the rule. Plants that choose to invest in innovative research of membrane and paste encapsulation or other similar technologies should have longer

timeframes to develop these applications. A minimum of eight years is needed, as explained below.

Southern Company Services, Inc. conducted research on membranes and paste encapsulation at the Water Research Center at Plant Bowen in 2013-2018. Extensive research was conducted on an advanced membrane technology from one vendor and a pilot-scale paste encapsulation system. Membrane studies revealed potential issues with scaling and corrosion and the frequency of their maintenance and replacement. A majority of the paste encapsulation pilot studies were focused on optimizing the recipe for mixing the concentrated brine with fly ash and lime to make a paste that is pumpable and sets up like concrete once introduced into a landfill. Limited studies were conducted on long-term properties of the paste in a landfill. Although many insights were gained through this research, significantly more research and development are needed to better understand these technologies. For instance, a facility would need to conduct pilot studies for both membrane technology (including pre-treatment requirements) and paste encapsulation, as well as evaluate paste disposal and its long-term stability.

For future studies, Southern Company Services' engineers recommend evaluating several membrane technologies, including pre-treatment technologies. They also recommend investigating various paste materials (fly ash, lime, etc.) and mixtures of paste materials, including their curing times and other characteristics, as well as issues associated with transporting the paste and depositing it in a landfill. These studies would need to be conducted holistically to assure that the combined technologies are being fully investigated. Long-term monitoring would be necessary to understand how the paste performs when it is deposited in a landfill over time. Due to the lack of experience with these technologies and variations in FGD wastewater at each facility, further investigations must be conducted on a facility basis, and challenges that have not been identified will have to be addressed. Southern Company estimates that at least eight more years of research is needed before a full-scale/commercial application combining these technologies can even be considered for a given facility.

As stated above, EPA has correctly concluded that membrane filtration and paste encapsulation technologies are not BAT for the industry. Again, at least eight years of substantial additional research is needed before these combined technologies could possibly reach the state of engineering feasibility. Inclusion of these systems in the VIP is ideal, however, because it will likely accelerate the development of the technology. Even still, there is no reasonable basis upon which EPA or anyone can declare that this technology will be BAT in 2028.

51 2015 Rule, 80 Fed. Reg. at 67,868.
52 Id.
53 Proposed Rule, 84 Fed. Reg. at 64,637.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 10

Comment Excerpt:

Fourth, EPA's proposed revisions to the Voluntary Incentive Program (VIP) are appropriate since thermal evaporation technology is not BAT. EPA should finalize the VIP limits for FGD wastewater using membrane filtration as the technology basis for these limits, as well as the compliance deadline of December 31, 2028.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 15

Comment Excerpt:

5. EPA should establish the FGD WW Voluntary Incentive Program (VIP) after making needed clarifications.

Like the 2015 Rule, EPA established a VIP for FGD WW that would allow for additional time to achieve compliance with ELG requirements if companies decided to utilize additional wastewater treatment technologies beyond what is identified as BAT and these technologies would have to meet more stringent limits. These additional treatment technologies would provide significant environmental protections and, in some cases, also provide regulatory certainty.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 16

Comment Excerpt:

A. EPA correctly concludes that VIP technologies are not BAT for FGD WW.

By allowing for an extended compliance applicability date for VIP technologies, EPA is concluding that such technologies do not meet the CWA requirements for BAT. Although such technologies exist, additional research, engineering and testing of these technologies are needed to ensure they can be reliable technologies for FGD WW with the potential to improve economic viability.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 17

Comment Excerpt:

B. EPA should clarify and allow other FGD WW technologies to qualify for the VIP.

Brine concentration technologies are not the only technologies capable of achieving significant environmental protection. Other technologies exist that could achieve a zero liquid discharge of FGD WW, such as Spray Dryer Absorbers or in-duct evaporators. However, based on the existing language of the 2019 proposal, it is difficult to determine if such technologies are eligible for the VIP. In the final ELG Rule, EPA should clarify that any technology that either meets the discharge standards proposed for the 2019 VIP or achieves zero liquid discharge qualifies for the VIP, specifically the applicability date of December 31, 2028.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 18

Comment Excerpt:

C. VIP Technologies from 2015 ELG Rule and proposed in the 2019 proposal are different but offer the same environmental protection.

In the 2015 Rule, EPA identified thermal evaporation technologies as the basis for the VIP program. In the 2019 proposal, EPA changed their basis to membrane technologies. However, both technologies are considered concentration technologies as they both result in a brine that needs to be managed and disposed. EPA solicits comment on whether membrane technologies can be used “in lieu of, or in combination with, thermal technologies[16].” As the 2019 proposal indicates, more research and engineering is needed to ensure the reliable applicability of membranes for FGD WW treatment and that they could be used in conjunction with other thermal concentration technologies. But to identify one specific concentration technology as basis for VIP is premature. EPA should clarify the technology basis for the VIP in the 2019 proposal to be brine concentration technologies, and not identify one concentrate technology over the other.

[16] Fed. Reg. Vol 84, p. 64634

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 10

Comment Excerpt:

While APPA agrees the technology basis for BAT should not be membrane filtration technology, the Associations does support basing the VIP option on membrane filtration technology but requests a few clarifications. First, APPA recommends EPA specify that VIP does not require a specific technology. In addition, APPA supports providing at least eight years for facilities to research, select, design, obtain regulatory approvals, procure, install, commission and optimize new technology. If a facility certifies it will achieve the VIP limits for FGD wastewater by the applicability dates, EPA should allow the longer time frame irrespective of the technology selected.

Commenter Name: Clark Harrison
Commenter Affiliation: Purestream Services, LLC
Document Control Number: EPA-HQ-OW-2009-0819-8289-A1
Comment Excerpt Number: 12

Comment Excerpt:

9. For the Voluntary Incentives Program, the EPA has switched its preference from proven thermal and encapsulation technologies to advanced membrane filtration and paste technologies. The preference is based on the hope that advanced membranes and pates technologies will both be proven and affordable by the time they are needed by a volunteer.

Incentives should be based on desired outcomes rather than specific processes. There is insufficient evidence presented in the Technology Development Document and the preamble to the proposed rule to conclude that thermal and brine encapsulation technologies that have proven performance and improved economics should be put aside based on optimism and hope for new membrane and paste technologies. On one hand, the EPA appears to be raising the bar by requiring voluntary participants to rely on less proven technology and on the other hand, the EPA may be lowering the bar by moving away from the goal of ZLD. The Voluntary Incentives Program would be more easily understood and may attract more volunteers if the requirement was simply stated as measurable discharge limits or goals (ZLD, for example). Rather than prescribing certain technologies with unknown future consequences, the EPA should leave the process selection and engineering decisions to the power plant owners and their consultants. Volunteers should be encouraged to apply their own cost-benefit analyses, select the right solutions for their plants and execute those solutions to benefit the environment and their stakeholders.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 17

Comment Excerpt:

Accordingly, understanding the agency's basis for projecting VIP enrollment is critical to evaluating the reasonableness of EPA's projected benefits, and the cost-benefit analysis of the Proposed Rule over all.

But EPA provides no explanation of its methodology. The agency claims that its prediction assumes 18 plants will find it more cost-effective to opt into the VIP instead of following the default effluent limitations guidelines.[125] But neither the Proposed Rule, nor the Regulatory Impact Statement, nor the Benefit and Cost Analysis, nor the Technical Support Document, nor the ERG Memorandum on changes to industry profile discusses in any detail how the agency arrived at this number.[126]

Furthermore, it is speculative that plants will opt into the VIP program. Because EPA is significantly relaxing the default BAT/PSES limitations guidelines for the overall power plant category and for subcategories, it is not intuitive that facilities would opt into the VIP program as a more affordable alternative. Moreover, as discussed in Part III, the grandfathering provision significantly decreases the appeal of the VIP program. If facilities can delay compliance until the end of 2028 and then meet default standards under the grandfathering provision, it is unclear why facilities would instead choose to delay compliance until the end of 2028 and meet more demanding standards under the VIP provision. Thus, EPA likely greatly overestimates the bromide benefits associated with the Proposed Rule.

125 BAC at 3-3

126 See generally Proposed Rule; BAC; EPA, SUPPLEMENTAL TECHNICAL DEVELOPMENT DOCUMENT FOR PROPOSED REVISIONS TO THE EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR THE STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY (2019); RIA; ERG, Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule – DCN SE07207 (2019).

Commenter Name: Anonymous
Commenter Affiliation:
Document Control Number: EPA-HQ-OW-2009-0819-8408
Comment Excerpt Number: 1

Comment Excerpt:

I am writing in opposition to this proposed rule. Given that the 2015 rule likely underestimated the risks that coal ash and waste water create for the American people and our environment, now is not the time to prioritize the profits of a struggling coal industry.

I am concerned on the agencys reliance on voluntary surveys and data. This rule is based on voluntary water sampling from only two of seven facilities asked to participate. However, in its current form, the rule does not elaborate on whether these facilities are typical or representative of the water facilities across the country.

I am skeptical that the flexibility this rule seems to focus on is the best way to approach regulating coal ash and waste water. My concern is that this alleged flexibility merely allows coal facilities to play down to the standards set for the worst polluters and contaminators, while hiding under the guise of different climates and maintenance needs.

Furthermore, I am unconvinced that the rules voluntary incentive program provides sufficient incentives to motivate compliance. This proposed rule change is allegedly into response to the downturn that the coal industry has experienced. If this trend continues, coal facilities could be encouraged to simply wait for more and more lenient regulations. As the country moves towards cleaner forms of energy and the market shifts, the government should incentivize innovation rather than prop up an increasingly obsolete industry.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 9

Comment Excerpt:

TVA believes that EPA's prediction of the facilities that would opt for M+E may be overstated based on the inclusion of TVA's Kingston and Paradise sites as M+E plants for Option 3 of the ERG's unit-level table (Generating Unit-Level Costs and Loadings Estimates by Regulatory Option- DCN SE07090, (ERG memo). Because TVA strives to market CCRs, TVA would not likely opt for M+E because the fixation step reduces the amount of CCRs available for marketing and in some instances may require sites to bring in fly ash for encapsulation. If these TVA sites were included in EPA's prediction of facilities who would adopt (M+E), then TVA requests they be deleted.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 23

Comment Excerpt:

EPA claims these health benefits will result under the Option 2 scenario because plants will opt-in to the Voluntary Incentives Program. But there is no basis for this assumption; on the contrary, EPA appears to be attempting to use the benefits of a more protective technology—the membrane filtration of the VIP option—to enhance its evaluation of a less-protective approach, Option 2. EPA claims, for example, that Santee Cooper's Cross and Winyah plants would be among those that would adopt the VIP approach—but when we asked, Santee Cooper reported that it has made no such decision and that it has never indicated to EPA (or otherwise) that it was planning to adopt this technology.[36] SCE&G/Dominion likewise reported that it has not decided to adopt this technology for its South Carolina facilities listed on EPA's table.[37]

In other words, EPA's analysis is based on pure speculation.

[36] Telephone conversation with Vice President for Environmental and Water Systems (Jan. 14, 2020).
[37] Telephone conversation with Vice President for Fossil and Hydro Operations (Dec. 19, 2019).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 63

Comment Excerpt:

VIII. THE PROPOSED VOLUNTARY INCENTIVE PROGRAM IS UNLAWFUL, UNNECESSARY, AND EPA'S CLAIM THAT IT WILL RESULT IN SIGNIFICANT REDUCTIONS OF POLLUTION IS NOT SUPPORTED BY THE RECORD.

A. EPA Proposes To Provide A Compliance Extension for Sources That "Voluntarily" Meet Discharge Limits That Are Stricter Than Those EPA Otherwise Proposes.

EPA proposes to create a compliance extension to the end of 2028 for facilities discharging FGD wastewater whose owner or operator "voluntarily chooses to meet the effluent limitations" which are based on membrane filtration technology and which are more stringent than the proposed limitations for facilities not making this election.[222] The proposal does not specify how (or even whether) a facility owner or operator must commit to meeting the new limits, nor identify specific consequences beyond meeting the otherwise-applicable requirements if someone changes his/her mind and chooses not to meet the more stringent limitations. As discussed in the following sections, this "voluntary incentive program" ("VIP") violates the Clean Water act, lacks record support, and is otherwise arbitrary and capricious.

[222] 84 Fed. Reg. at 64,674 (proposed 40 C.F.R. § 423.13(g)(3)(i)); id. at 64,637 (describing rationale for choice of technology basis).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 66

Comment Excerpt:

C. The Proposed Voluntary Incentive Program Unreasonably Fails to Consider Critical Issues and Lacks a Basis in The Agency's Administrative Record.

EPA's plans for implementing the VIP and its claims about the likely participation in the program irrationally disregard important matters and are factually unsupported. Accordingly, they are arbitrary and capricious.[232]

The most important way in which the proposed VIP ignores important factors is that it lacks virtually any implementation details. For instance, the proposed rule inexplicably fails to specify how a discharger would opt in to the VIP, much less include requirements to ensure that those owners/operators taking advantage of the VIP's extended compliance delay actually meet the VIP effluent limits. Relatedly, the VIP does not include a mechanism to ensure that plants that might withdraw from the program would be required to timely comply with FGD wastewater limits. [233] The proposed program's lack of consequences for withdrawing from the VIP, combined with EPA's failure to require VIP participants ultimately to meet the stricter limits, is particularly unreasonable because it permits unscrupulous operators to make an end-run around the principal set of effluent limitations for an extended period of time by simply claiming they will voluntarily meet the stricter standards later. Because of these critical omissions, EPA cannot predict with any confidence which facilities will meet the VIP effluent limits, versus facilities for which the owner/operator merely will announce an intention to do so.

EPA also ignores a critical factor in any Clean Water Act rulemaking – the purpose of the Act, including the ELG program. These ELGs are required to be technology-forcing and to achieve expeditious compliance, as evidenced by the Act's requirement that toxic pollutant dischargers meet BAT limits that are achieved "as expeditiously as practicable," and its requirement for regular review of ELGs' adequacy.[234] However, the VIP undermines these fundamental statutory goals. For instance, the proposal assumes that eighteen power plants will participate in the program under EPA's preferred regulatory option,[235] but then ignores the obvious upshot of that conclusion: a significant subset of facilities using a specific technology because it is economically practicable for their operation only underscores that such technology –namely, membrane filtration in this case – must be considered BAT and required across the industry. As noted in the Legal Background section of these comments, a technology is "available" if it is in use in the industry, even if only by the best-performing plant in the industry, or if it can be demonstrated to be available through pilot studies or its use in other industries, and a technology is economically achievable if the costs can be reasonably borne by the industry as a whole.

Additionally, the rationale for the proposed compliance delay to the end of 2028 for power plants that participate in the program runs counter to the evidence before the agency. Although EPA claims that the 2028 "timeframe is based on the amount of time necessary to pilot, design, procure, and install both the membrane filtration systems and the brine management systems,"[236] the agency provides no evidence to support its argument and materials in the record indicate otherwise. In particular, Northern Indiana Public Service Company ("NIPSCO") met with EPA and provided its arguments in support of an extended compliance deadline, relying in part on its estimate of the time for the final ELGs to be litigated and for state public utility commission processes; however, neither of those factors has anything to do with the achievability of the limits.[237] Even with those additional considerations, NIPSCO argued that retrofitting facilities as part of a VIP could be accomplished by 2026. Interestingly, EPA's own economic analysis shows that fifteen of the eighteen facilities it anticipates participating in the VIP would find membrane technology to be the least costly option if the agency established a VIP compliance date of 2025.[238]

Finally, the VIP is premised on an assumption that contradicts the evidence before the agency. In particular, EPA has not demonstrated that a significant number of power plants will participate in the program. The 2015 rule's VIP was only opted into by a small number of plants that had other reasons for opting in; the program by itself failed to incentivize significant reductions in pollution. EPA's own preamble admits this, saying that facilities installing the VIP- level technology did so due to "water quality-based effluent limitations imposed by the NPDES permitting authority,"[239] not because of the incentive of additional compliance time.

[232] *Motor Vehicle Mfrs. Assn. v. State Farm Mut. Auto. Ins. Co.,* 463 US 29, 43 (1983) (agency rule is arbitrary and capricious if, among other things, "the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise").
[233] Although we strongly opposed the loophole that the proposed VIP would create for the reasons discussed in this section, if EPA nevertheless proceeds to finalize the scheme, it must adopt provisions to guarantee facilities' compliance with the VIP limits. For instance, EPA could require facility owners and operators to certify promptly that they will participate in the VIP and require that such facilities' NPDES permits specify that the stricter limits will be automatically applicable on the VIP compliance date.
[234] 33 U.S.C. §§ 1311(b)(2)(C) & (d).
[235] Proposed BCA at p. 2-1.
[236] 84 Fed. Reg. at 64,637.
[237] Email from Nicholas M. Dernik, NiSource, Inc., to Richard Benware, EPA, Docket ID No. EPA-HQ-OW-2009-0819-8274 (July 17, 2018); email from Nicholas M. Dernik, NiSource, Inc., to Richard Benware, EPA, Docket ID No. EPA-HQ-OW-2009-0819-8275 (June 8, 2018).
[238] EPA, VIP Plant Flags and Analysis Comparing Technology Costs – DCN SE07652, Option 2 VIP Comparison, Docket ID No. EPA-HQ-OW-2009-0819-7706.
[239] 84 Fed. Reg. at 64,637.

Commenter Name: Jennifer Peters, et al.
Commenter Affiliation: Clean Water Action, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8462-A1
Comment Excerpt Number: 4

Comment Excerpt:

EPA's claim that the Voluntary Incentive Program (VIP) will result in significant pollution reductions lacks merit: Instead of requiring power plants to use the best available membrane technology to control FGD discharges, EPA is proposing to provide plants that voluntarily install this technology an additional five years (until 2028) to comply with these standards. EPA included a similar voluntary incentive program in its 2015 final steam electric ELG rule but it does not appear any power plants opted into that program. EPA's claim that its latest VIP "would achieve greater pollution reductions than the 2015 rule would have achieved" is baseless.

Commenter Name: Michael P. Alaimo
Commenter Affiliation: Clean Fuels Michigan, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8305-A1
Comment Excerpt Number: 7

Comment Excerpt:

EPA's claim that the Voluntary Incentive Program (VIP) will result in significant pollution reductions lacks merit: Instead of requiring power plants to use the best available membrane technology to control FGD discharges, EPA is proposing to provide plants that voluntarily install this technology an additional five years (until 2028) to comply with these standards. EPA included a similar voluntary incentive program in its 2015 final steam electric ELG rule but it does not appear any power plants opted into that program. EPA's claim that its latest VIP "would achieve greater pollution reductions than the 2015 rule would have achieved" is baseless.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 69

Comment Excerpt:

UWAG generally supports the proposed VIP option based on membrane filtration technology but requests a number of clarifications. First, EPA should clarify that the VIP does not require a specific technology (i.e., membrane filtration). Any technology that meets the VIP limits should qualify. Second, UWAG agrees that *at least* eight years are needed for facilities to research, select, design, get regulatory approval, procure, install, commission and optimize any new technology, as explained below.

The VIP program would allow UWAG members who choose to invest in innovative research of membrane and paste encapsulation technologies (or other similar technologies) to have the time necessary to develop these applications. So long as the facility certifies that it will achieve the VIP limits for FGD wastewater by the applicability date, EPA should allow the longer timeframe regardless of what technology or approach the facility intends to use. For example, if the facility intends to reach the level of treatment consistent with membrane filtration and paste encapsulation by installing spray dryers, using brine to condition ash, or thermal reduction, those alternative methods should be acceptable approaches because the pollutant reduction is the same. Also, having the flexibility to use different means of reaching the same pollutant reduction makes sense, as the membrane filtration and paste encapsulation processes are not yet demonstrated. Should research prove that membrane filtration or paste encapsulation is unsuitable at any site, the facility then would be able to employ another approach to achieve the ELGs.

The applicability date for any facility that opts into the VIP should be *at least* eight years from the effective date of the rule. As EPA recognizes in the proposal, the "timeframe is based on the amount of time necessary to pilot, design, procure, and install both the membrane filtration systems and the brine management systems," 84 Fed. Reg. at 64,637, but EPA does not cite any documents in support of this statement. UWAG members' engineers and other in-house experts have performed their own analysis and found that the schedule to properly implement membrane and paste encapsulation technology, or any technology that qualifies for the VIP, necessitates at least eight years.

Full commercialization of a membrane and paste encapsulation system would require the facility to first develop options for pilot programs and evaluate which membrane technology would be most appropriate. At the same time, the facility would need to develop options for brine disposal and begin research on paste encapsulation technology. EPA's record indicates that small-scale membrane technology pilot programs require approximately 1-12 months depending on the membrane technology.[111] The process to develop a pilot program and conduct testing for paste encapsulation would likely take much longer because the engineers would need to produce brine for paste testing, begin selecting and experimenting with materials at the bench scale to develop the mix design, develop the hardened paste properties at the bench scale through curing, and review the bench scale results to plan the pilot scale testing. At the pilot scale, the facility would need to test and design various methods to transport and deposit the paste and verify the field performance of hardened paste. Long-term monitoring would be necessary to understand how the paste performs when it is exposed to environmental conditions over time. Due to the lack of data and experience with these technologies, all of these initial steps involve unpredictable outcomes and challenges and could create new issues that experts have yet to identify.

Assuming the facility is able to resolve any problems identified during pilot testing and seeks to implement the technology at the commercial scale, it would move to the procurement stage. Here, the facility would need to finance the investment in new equipment, identify appropriate vendors, and order the necessary equipment. The facility also would need to prepare applications and seek regulatory approvals for the project from the public service commission ("PSC") and other federal, state, and local agencies. Preparing the site, installing, testing, and optimizing the equipment would also require a significant amount of time.

Any timeline would also need to allow for contingencies, such as delayed equipment deliveries, construction delays due to weather, and other common challenges for major retrofits. This is why the timeframe for implementation should be at least eight years.

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[111] See, e.g., ERG, *Memorandum re: Technologies for the Treatment of Flue Gas Desulfurization Wastewater,* EPA-HQ-OW-2009-0819-8155 (Oct. 22, 2019), App. B at B-3 – B-8; id. at App. K at K-6 – K-12.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)

Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 4

Comment Excerpt:

- As to emerging technologies, EPA appropriately decided that a combination of membranes and paste encapsulation is not a demonstrated technology for FGD wastewater treatment. EPA's plan to instead use that technology as the basis for a "voluntary incentive program" is promising, provided EPA allows at least 8 years for the further research and development of these technologies.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 9

Comment Excerpt:

Nonetheless, with at least 8 years to study these technologies, it is possible that some facilities will be able to use EPA's proposed "voluntary incentive program" option.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 128

Comment Excerpt:

B. A Longer Applicability Date is Appropriate for the VIP Program.

As discussed elsewhere in these comments, UWAG endorses EPA's proposal to provide additional time for permittees who choose to design for compliance using "beyond BAT" technologies such as membranes, followed by solidification and landfilling of the resulting brine. Given the substantial uncertainties surrounding the performance and cost of those technologies, facilities for which those technologies are even theoretically plausible are unlikely to pursue them without the additional time needed for further research and evaluation, pilot testing, development of specialized landfills, technology procurement and installation, and commissioning. The eight years proposed is the minimum amount of time needed to accommodate and incentivize further development of this technology.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 3

Comment Excerpt:

Second, GSP Merrimack supports the proposed revisions to the Voluntary Incentives Program for FGD wastewater in § 423.13(g)(3)(i). However, for those revisions to serve their purpose, EPA must also revise existing § 423.13(g)(3)(ii) to align the date in that subsection with the new proposed December 31, 2028 deadline in proposed subsection (g)(3)(i). Without this additional revision to existing § 423.13(g)(3)(ii), there may be a gap in application of the new regulations.

Commenter Name: James S. Andrews
Commenter Affiliation: GSP Merrimack LLC
Document Control Number: EPA-HQ-OW-2009-0819-8459-A1
Comment Excerpt Number: 9

Comment Excerpt:

II. EPA Should Revise Existing § 423.13(g)(3)(ii) to Align the Date with the New December 31, 2028 Deadline in Revised § 423.13(g)(3)(i)

GSP Merrimack agrees with EPA's proposed revision of the Voluntary Incentives Program for FGD wastewater, including the new deadline of December 31, 2028, to meet the more stringent effluent limits. However, EPA must also revise existing § 423.13(g)(3)(ii) to align the dates in that Voluntary Incentives Program provision with the new December 31, 2028 deadline. At present, § 423.13(g)(3)(ii) provides discharge limitations "before December 31, 2023." That date should be revised to December 31, 2028, so that there is continuity on the national effluent limits applied to a unit that has opted into the Voluntary Incentives Program. Importantly, § 423.13(g)(3)(ii) was not addressed or vacated by the Fifth Circuit's decision in Southwestern Electric Power Co. v. EPA, 920 F.3d 999 (5th Cir. 2019) ("SWEPCo"), which considered other provisions in the 2015 ELG rule. Specifically, with respect to so-called "legacy wastewater," the Environmental Petitioners in that case expressly requested review and vacatur of only 40 C.F.R. § 423.13(g)(1)(ii), (h)(1)(ii), and (k)(1)(ii)—none of which involve the Voluntary Incentives Program.[1] In subsequent filings with the Court, Environmental Petitioners made clear once again that § 423.13(g)(1)(ii) was not among "[t]he legacy wastewater and leachate provisions that Environmental Groups are challenging in this case[.]"[2] Indeed, the Environmental Petitioners did not challenge any aspects of the Voluntary Incentives Program or EPA's rationale for it, and thus any challenge to § 423.13(g)(3)(ii) was waived.[3] The Fifth Circuit's decision also did not discuss the lawfulness of the Voluntary Incentives Program or § 423.13(g)(3)(ii), and thus cannot be interpreted as vacating that provision.[4] Indeed, the Fifth Circuit did not consider EPA's distinct rationale for the Voluntary Incentives Program in the 2015 rule, and thus its decision could not, even by implication, have found any provision in § 423.13(g)(3) to be arbitrary and capricious.

Evaporative treatment is the model technology for the Voluntary Incentives Program for FGD wastewater. EPA considered identifying that technology as BAT for the industry in promulgating the 2015 rule but ultimately elected to not do so because of the high costs associated with it. 80 Fed. Reg. 67,838, 67,852 (Nov. 3, 2015). Thus, the Voluntary Incentives Program imposes more stringent discharge limitations beyond those imposed by the final BAT limitations applicable to the rest of the industry. Id. at 67,858. EPA recognized facilities that "opted-in" to the Voluntary Incentives Program would not be able to immediately comply with the more stringent limits. Instead, additional time "to research, engineer, design, procure, construct, and optimize systems capable of meeting the limitations" would be required. Id. at 67,858- 59. Despite this, EPA elected to promulgate the Voluntary Incentives Program because of the agency's beliefs that the program, as a whole, "furthers the CWA's ultimate goal of eliminating the discharge of pollutants into the Nation's waters." Id. at 67,858. The Program represents "reasonable further progress toward the national goal of eliminating the discharge of pollutants." Id. (quoting 33 U.S.C. §§ 1251(a)(1), 1311(b)(2)(A)). It is "technology-forcing"[5] insofar as it should "effectively accelerate the research into and demonstration of controls and processes intended to prevent, reduce, and eliminate pollution," consistent with CWA § 104(a)(1). Id. The interim limits in § 423.13(g)(3)(ii) are an essential part of the Voluntary Incentives Program because they, along with the additional time allotted, motivate entities to undertake the research EPA desires. EPA determined these § 423.13(g)(3)(ii) limits are sufficiently protective in the interim—and promulgation of them is justified—because of the considerable benefit the agency and general public will receive through the accelerated research completed by participants in the Voluntary Incentives Program. Nothing in the Fifth Circuit's decision addresses or questions the agency's choice to structure the Voluntary Incentives Program as it did to achieve this ultimate goal, and, indeed, the Court was careful to state that it was not "second-guess[ing] [EPA's] weighing of the statutory factors." SWEPCo, 920 F.3d at 1022. Accordingly, the Voluntary Incentives Program, including § 423.13(g)(3)(ii), remains "on the books" and is presently applicable to any and all newly-issued NPDES permits that involve FGD wastewater where the facility has elected to be part of the program. Indeed, Merrimack Station is presently opted-in to the program as part of its pending permit application before EPA Region 1. And, due to the same reasons cited by EPA as justification for the Voluntary Incentives Program, Merrimack Station will require at least until December 31, 2023, to meet the more stringent limitations based on evaporation technology, and perhaps longer due to changes in the Station's ownership and operational profile.[6] For these reasons, EPA should, as part of this current rulemaking, also revise the 2023 date set out in § 423.13(g)(3)(ii) to conform to the new Voluntary Incentives Program deadline of December 31, 2028.

[1] See Brief of Petitioners Environmental Integrity Project, Sierra Club, and Waterkeeper Alliance, Inc. at 66, Sw. Elec. Power Co. v. EPA, No 15-60821 (5th Cir. Dec. 5, 2016) (Doc. 00513785014) (Attachment 1).
[2] See Response to Sierra Club, Environmental Integrity Project, Waterkeeper Alliance, Inc., and Clean Water Action in Opposition to Respondents' Motion to Govern Further Proceedings at 6 n.3, Sw. Elec. Power Co. v. EPA, No 15-60821, (5th Cir. Aug. 18, 2017) (Doc. 00514123143) (Attachment 2).
[3] See Shami v. Comm'r of Internal Revenue, 741 F.3d 560, 572 (5th Cir. 2014) ("[I]ssues not raised in a party's opening brief are waived.").
[4] See Worldcall Interconnect, Inc. v. Fed. Commc'ns Comm'n, 907 F.3d 810, 825 (5th Cir. 2018), as revised (Nov. 15, 2018) ("We find that WCX did not raise this argument in its petition for review. . . . Therefore, this argument is not properly before this court.").
[5] See SWEPCo, 920 F.3d. at 1003 (quoting NRDC v. EPA, 822 F.2d 104, 123 (D.C. Cir. 1987)).
[6] The evidence in the administrative record for the Merrimack Station permit renewal demonstrates that December 31, 2023, is the earliest date by which the more stringent Voluntary Incentives Program limitations could be met at

Merrimack Station, for the very reasons EPA cited in the 2015 rule. See, e.g., Letter from Eversource Energy to EPA Region 1 (July 7, 2016), https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-1354.pdf.

35 Regulatory Implementation – Compliance Monitoring

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 48

Comment Excerpt:

B. Plants Producing FGD Wastewater Generally Will Not be Operating in a Steady State but Will be Cycling.

The use and dispatch of coal-fired generation has changed significantly since 2015, and a majority of coal-fired plants now operate on a cycling basis. Cycling on and off causes difficulties with biological treatment systems. Even if all appropriate steps are taken to lessen the effects of cycling on the microbes within the system, changes in wastewater flows or concentrations can affect the microbes, which must acclimate to each change. This acclimation factor means that the effectiveness of the biological treatment system can be reduced for some period of time after a change in wastewater flow or quality.

In managing the pilot data used to set FGD limits, EPA excluded data that the Agency determined was "Prior to Steady-State Operation" or collected during "Treatment System Upset or Abnormal Operation." *See*, Supplemental SSD, Appendix 2. However, for peaking plants, it is often the case that they are not in steady state operations. Using EPA's data on net generation shows that the percent utilization of the generating units expected to produce FGD wastewater is relatively low.

Percent Utilization Information for Generating Units that Produce FGD Wastewater, Based on 2016 Generation Data[60]

MWh Ranges of FGD Units	Number of Units in each range	Avg Net Generation (MWh)	Sum Net Generation (MWh)	Avg. % Utilization	Maximum % Utilization	Minimum % Utilization
<876,000[61]	47	483,205	2,710,641	26.80%	59.60%	1.50%
>876,000, <1,314,000	14	980,385	13,725,834	43.60%	64.50%	20.50%
>1,314,000, <1,752,000	8	1,505,178	12,259,227	53.60%	71.8%	39.5%
>1,752,000	98	3,205,437	336,710,641	54.30%	84.2%	22.0%

The category of the largest units (>1,752,000 MWh) only average 54.3 percent utilization, and the smaller units which will be subject to biological treatment requirements are used even less. This table indicates that a large number, perhaps a majority of FGD units that are required to install the LRTR technology, are likely peaking or cycling units with utilizations at or under 50 percent. Such facilities would regularly face long periods of shutdown. As a result, their biological treatment systems would need time to acclimate once the FGD wastewater flow returns to normal operating levels.[62] This means that the system may not be able to immediately meet the proposed limits.

The problem of acclimation times for cycling units is exacerbated by the lack of online, real-time monitors for selenium and mercury. While research is ongoing to develop reliable online monitors, as yet there are no online monitors that can be used within FGD wastewater treatment systems to allow real-time analysis of selenium and mercury levels.[63] EPRI has performed extensive laboratory and field tests of online water quality monitors for selenium and mercury in FGD wastewater, but currently finds that none of the monitors it has tested in the field "exhibited the required sensitivity, accuracy, and ruggedness for use in this application."[64] Without reliable online monitors, operators are dependent on laboratory analyses that can take days or weeks to produce results. In that amount of time, the system could be out of steady state, and the operator would not have any means of identifying that problem and would lack the analytical data necessary to rectify the situation.

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[60] Analysis based on net generation provided in ERG, Unit Costs & Loadings, Table 2.
[61] Under the Proposed Rule, units less than 876,000 MWhs as a two-year average net generation would not be subject to biological treatment requirements.
[62] While EPA contends that biological treatment systems can be managed to account for cycling of units, 84 Fed. Reg. at 64,631, industry experience does not support that conclusion, particularly in the absence of reliable online monitors.
[63] See EPRI 2020 Comments, at 3-5.
[64] Id.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 17

Comment Excerpt:

B. On-line Monitors are Essential for Real-Time Measurement of Selenium and Mercury but are Not Commercially Proven for FGD Wastewater.

Real-time measurement of arsenic, mercury, and selenium for process control of chemical precipitation and biological treatment of FGD wastewater is essential to providing prompt warning of exceedances of the ELG limits. Commercial and in-house laboratories can take days to weeks to turn around analytical results of process samples. Both EPRI and Alabama Power Company have performed extensive laboratory and field tests evaluating on-line monitors capable of real-time measurement of arsenic, mercury and selenium in FGD wastewater. Multiple vendors make claims of application in FGD wastewater; however, after significant vetting and testing, no proven, commercially available technologies for FGD on-line monitoring application exist. [21]

Alabama Power continues to work with vendors to reduce the unacceptable downtime and significant operations-and-maintenance ("O&M") costs required to operate a monitor. Recent studies demonstrate prototype monitors are showing greater accuracy and reliability, but they have not been tested on a full-scale FGD CP+LRTR biological treatment system. Alabama Power and EPRI plan to conduct further field testing of the prototype monitors this year, but until they are proven in the field and integrated into the process control system, it will be difficult to meet the proposed ELG limits on a consistent basis.

21 Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 3-5.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 49

Comment Excerpt:

C. Limits Based on Refined Coal are Not Appropriate.

EPA's last proposal is the promulgation of a limitation "that reflects the difference in concentrations naturally occurring in coal as opposed to levels found in refined coal or from other halogen applications."[110] EPA has not defined what constitutes "refined coal." A definition is needed. Moreover, this proposal seems to ignore that facilities are utilizing halogen applications out of necessity—to comply with MATS. This bromide issue therefore cannot be considered in a vacuum.

Attempting to craft an effluent limit that differentiates between bromide levels naturally occurring in coal versus levels attributable to additives would also be difficult, if not impossible. As stated above, bromide levels in the same coal type can vary widely, even within the same mine or coal seam.[111] Facility-specific factors, such as cycling up constituents of concern in the FGD scrubber, variations in the volume of effluent (or any associated volume reduction), and comanagement of wastewater prior to discharge, among others, could also cause naturally occurring bromide concentrations in effluent to vary widely across the industry.

Certain facilities utilizing halogens may also determine this tool is indispensable for MATS compliance. What then? Will they be required to install expensive, unproven treatment technologies regardless of whether they are located upstream of and in close proximity to a drinking water facility and/or whether the receiving waterbody into which effluent is discharged is capable of assimilating the constituents? These questions need to be thoroughly considered.

In the end, this proposal to establish a pointed limitation is not practical for the reasons set out herein. EPA should forego such a proposal and continue to endorse a water quality-based approach to address bromides on a site-specific basis.

110 Proposed Rule, 84 Fed. Reg. at 64,643.
111 See generally U.S. Geological Serv., COALQUAL DATABASE, supra note 109.

36 Regulatory Implementation – Bromide

Commenter Name: Jeanne M. VanBriesen and Kelly D. Good
Commenter Affiliation: Carnegie Mellon University and Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8296-A1
Comment Excerpt Number: 1

Comment Excerpt:

Flue gas desulfurization wastewater should be monitored regularly for bromide concentrations in a way that captures variability. This monitoring should take place at an internal monitoring point prior to mixing with other wastewaters. If FGD treatment is used, monitoring for bromide should be directly after treatment since treatment of FGD wastewater designed to remove other constituents may not remove bromide.

Commenter Name: Jeanne M. VanBriesen and Kelly D. Good
Commenter Affiliation: Carnegie Mellon University and Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8296-A1
Comment Excerpt Number: 2

Comment Excerpt:

Flue gas desulfurization wastewater should be monitored regularly for bromide concentrations in a way that captures variability. This monitoring should take place at an internal monitoring point prior to mixing with other wastewaters. If FGD treatment is used, monitoring for bromide should be directly after treatment since treatment of FGD wastewater designed to remove other constituents may not remove bromide.

Commenter Name: Jeanne M. VanBriesen and Kelly D. Good
Commenter Affiliation: Carnegie Mellon University and Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8296-A1
Comment Excerpt Number: 3

Comment Excerpt:

Monitoring data should be included in NPDES permit applications so that regulators can consider the need for case-by-case water quality based effluent limitations (WQBELs) or technology-based effluent limitation (TBELs) in each NPDES permit issued to a utility discharging FGD wastewater to the environment.

Commenter Name: Jeanne M. VanBriesen and Kelly D. Good
Commenter Affiliation: Carnegie Mellon University and Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8296-A1
Comment Excerpt Number: 4

Comment Excerpt:

1. Flue-gas desulfurization wastewater bromide concentrations should be included in NPDES permit applications. The Clean Water Act (40 C.F.R. §122.21) requires a permit applicant to "indicate whether it knows or has reason to believe that any of the pollutants in Table IV of appendix D of this part (certain conventional and nonconventional pollutants) is discharged from each outfall. If an applicable effluent limitations guideline (ELG) either directly limits the pollutant, or by its express terms, indirectly limits the pollutant through limitations on an indicator, the applicant must report quantitative data. For every pollutant discharged which is not so limited in an effluent limitations guideline, the applicant must either report quantitative data or briefly describe the reasons the pollutant is expected to be discharged." Appendix D includes bromide on the list of Conventional & Non-conventional Pollutants.[1] Thus, permit applications for coal-fired power plants with wet FGD systems that discharge to waterways should indicate bromide as an expected pollutant in the discharge of the outfall that contains the wet FGD wastewater. Unless EPA directly or indirectly limits bromide in the revised effluent limitation guidelines (ELGs), only qualitative mention in the application is required; however, we strongly recommend that quantitative data be required in each permit application. As demonstrated in our prior work, load estimates have significant uncertainty and variability that limits their utility for individual cases. Bromide loads should be assessed through measurement of concentration and flow data from each FGD system discharging wastewater to receiving waters.

[1] 40 C.F.R. §122.21. Table IV-Conventional and Nonconventional Pollutants Required to be Tested by Existing Dischargers if Expected to be Present. In Appendix D to Part 122 NPDES Permit Application Testing Requirements

Commenter Name: Jeanne M. VanBriesen and Kelly D. Good
Commenter Affiliation: Carnegie Mellon University and Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8296-A1
Comment Excerpt Number: 5

Comment Excerpt:

Our work has demonstrated that significant uncertainty remains regarding current and potential future bromide concentrations in wet FGD discharges (due to differences in coal use and bromide addition), and this uncertainty is similarly mentioned in the revised ELGs. We developed a method to estimate the bromide loads from power plants (see Good and VanBriesen, 2016) specifically because monitoring data were insufficient to allow these loads to be calculated. This estimation method is adequate for general assessment of the issue and for initial analysis of which power plants have the potential to cause bromide concentrations in receiving waters that could be of concern for downstream drinking water plants. But, it is unsatisfactory as a method to set permit-specific discharge limitations. It requires a prediction based on past coal usage (amount and type) and relies on estimates of bromide concentrations (and moisture levels) in different types of coal from a database that is many decades old (see the U.S. Geological Survey Coal Quality [COALQUAL] database). Since future coal usage may not be similar to past usage, and current mined coal may differ in bromide and moisture from samples from the past, this method introduces significant uncertainty in modeled bromide loads.

Commenter Name: Jeanne M. VanBriesen and Kelly D. Good
Commenter Affiliation: Carnegie Mellon University and Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8296-A1
Comment Excerpt Number: 6

Comment Excerpt:

The only adequate way to determine if load-based restrictions in bromide discharges from power plants are needed is to measure the bromide loads discharged at each power plant and consider how these loads are affected by the flow and existing concentrations of bromide in the receiving water. After this monitoring and assessment, a flow analysis must be undertaken for any receiving water that will subsequently (downstream) be a source water at a drinking water treatment plant. Our most recent paper (Kolb et al, 2020) provides extensive details on how to do this latter assessment, including incorporating assessment of the risk at the downstream drinking water plant associated with the discharged bromide from individual power plants. However, the analysis in that work is still dependent on a load estimate from the simulation model that contains significant uncertainty (due to input parameters) and variability (due to potential changes in coal type usage and bromide addition choices made by the power plant). Thus, direct measurements of bromide concentrations in FGD wastewater (from internal monitoring points before mixing with other wastewater) is needed to enable permit writers to assess which power plants must control bromide discharges to avoid increases in human health risk for drinking water consumers.

Commenter Name: Jeanne M. VanBriesen and Kelly D. Good
Commenter Affiliation: Carnegie Mellon University and Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8296-A1
Comment Excerpt Number: 7

Comment Excerpt:

2. Flue gas desulfurization wastewater should be monitored regularly for bromide concentrations, and this monitoring requirement should be in every NPDES permit issued to a power plant that operates a wet flue gas desulfurization system that discharges wastewater. This monitoring should take place at an internal monitoring point prior to mixing with other wastewaters. If FGD treatment is used, monitoring for bromide should be directly after treatment since treatment of FGD wastewater designed to remove metals may not remove bromide.

Bromide loads vary with the type of coal used and the addition of bromide for pollution control (e.g., to comply with MATS or to earn section 45 tax credits). Thus, routine monitoring is needed to identify any changes in bromide loading since the sampling included with the permit. Further, because of expected variability in bromide loads due to changes in coal and choices at the power plant (e.g., with respect to bromide addition), sampling methods that can capture this variability are needed.

Commenter Name: Jeanne M. VanBriesen and Kelly D. Good
Commenter Affiliation: Carnegie Mellon University and Villanova University
Document Control Number: EPA-HQ-OW-2009-0819-8296-A1
Comment Excerpt Number: 8

Comment Excerpt:

Grab sampling is unlikely to be suitable for wastewaters that have variable flow and concentration conditions. Flow-proportional sampling should be required to ensure representative load assessments can be made. This can be achieved by requiring a composite rather than a grab sample. In general, a composite sample means a combination of individual samples (e.g., at least eight for a 24-hour period or four for an 8-hour period) each obtained at spaced time intervals during the compositing period. The size of the sample specified should be sufficient to be representative. The composite must be flow-proportional, with the volume of each sample proportional to discharge flow rate or the sampling interval proportional to the flow rates over the time period used to produce the composite.This type of bromide sampling for FGD wastewater has been required in multiple permits in Pennsylvania recently.

Sample frequency should be set based on expected variability in the produced wastewater from the FGD system. Several recent PA permits require twice monthly (24 hour composite) bromide monitoring, with reporting of daily maximum and average monthly concentration as well as average monthly load. Required frequent flow monitoring (continuous with reporting of weekly and monthly averages) enables use of these concentration values to assess bromide load variability.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 5

Comment Excerpt:

Specifically, EPA should:

…

- Finalize EPA's proposed reliance on water-quality-based effluent limits (WQBELs) in lieu of nationally applicable BAT limits to address any potential impacts of bromides is appropriate and should be finalized. Should EPA determine that additional action with respect to bromides may be warranted at a national level, it is incumbent on EPA to address the issue meaningfully and comprehensively.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 11

Comment Excerpt:

Fifth and finally, should the Agency determine that additional action with respect to bromides may be warranted at a national level, it is incumbent on EPA to meaningfully and comprehensively address the issue as opposed to doing so in a piecemeal fashion. Water-quality-based effluent limitations (WQBELs) may be appropriate on a site-specific basis to address the potential impacts of bromides on downstream drinking water treatment facilities, as determined by state permitting authorities, and EPA's proposed reliance on WQBELs in lieu of nationally applicable BAT limits to address any potential impacts of bromides is therefore appropriate and should be finalized. Monitoring requirements applied to a single industry in an ELG rulemaking will not provide the data necessary to fully understand or resolve the problem.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 26

Comment Excerpt:

VIII. The Agency's Reliance On Water-Quality-Based Effluent Limitations For Bromides Is Appropriate; Should EPA Determine More Information On Bromides Is Needed, It Must Look At All Sources Of Bromides.

Consistent with the preamble to the 2015 ELG Rule, the Proposed ELG Rule again declines to establish bromide-specific requirements outside of the FGD wastewater VIP option while noting that WQBELs may be appropriate on a site-specific basis to address the potential impacts of bromides on downstream drinking water treatment facilities, as determined by state permitting authorities. See 84 Fed. Reg. at 64,642. However, EPA is requesting comment on three bromide-specific regulatory sub-options in addition to the proposed approach of retaining the 2015 rule's approach of leaving bromides to be limited by permitting authorities where appropriate using WQBELs: (1) A monitoring requirement under CWA section 308; (2) a bromide minimization plan using narrative or non-numeric limitations under CWA sections 301(b) and 304(b); or (3) a numeric limit under CWA sections 301(b) and 304(b) based on product substitution. Id.

EPA should finalize its proposed decision not to establish BAT limits for bromide in FGD wastewater and to continue relying on site-specific WQBELs, where appropriate, to address any potential impacts of bromides. [24] As an initial matter, technologies for bromide discharges have not been demonstrated and are cost-prohibitive, making technology-based limitations inappropriate. More importantly, however, a direct correlation between bromide concentrations at power plants and downstream formation of by-products such as trihalomethanes (THM) has not been established, as a multitude of factors dictate whether a bromide discharge will result in the formation of THM or other by-products, and multiple sources contribute bromides to surface waters. Additionally, even if bromide discharges from certain power plants may potentially impact downstream waters, data does not suggest that this is a nationwide problem that would necessitate the establishment of a national technology-based standard.

The State of South Carolina through the South Carolina Department of Health and Environmental Control (SCDHEC) has utilized a causation-focused approach to WQBELs. In 2011, total trihalomethanes (TTHMs) were detected above the MCL at three drinking water facilities on the Broad River. Through investigation and in-stream sampling upstream of the drinking water facilities, SCDHEC identified bromides as a causal factor in the formation of TTHM and further identified discharges from an industrial source as one of the sources of the elevated bromides in the Broad River. By working with the downstream drinking water facilities and the industrial source, a mutually agreed upon in-stream bromide concentration was established that would have no significant impact to the downstream drinking water facilities. Monitoring and reporting requirements were established, and the requirements were implemented through a consent agreement. This type of approach is well founded and can be utilized by EPA to take a more comprehensive look at addressing bromides—as opposed to doing so on an ELG by ELG basis.

Importantly, should EPA determine that additional action with respect to bromides may be warranted at a national level, it is incumbent on EPA meaningfully and comprehensively tp address the issue as opposed to in a piecemeal fashion, ELG by ELG. Monitoring requirements applied to a single industry in an ELG rulemaking will not provide the data necessary to fully understand or resolve the problem. The CWA requires EPA to work with its sister state and federal agencies to "conduct research on the harmful effects on the health and welfare of persons caused by pollutants in water." See 33 U.S.C. § 1254(a). With respect to bromides, EPA must include the comprehensive study of all types and sources of bromide discharges as well as factors contributing to THM formation as part of any research on the issue. Based on that information, EPA can then make an informed decision as to what, if any, national action—including the potential establishment of a national section 304(a) water quality criteria or a technology-based limitation applicable to one or more industrial sectors—may be warranted.

[24] For example: Pennsylvania Department of Natural Resources has addressed bromides through state issued NPDES permits, https://www.dep.pa.gov/About/Regional/SouthwestRegion/Community%20Information/Pages/Coal-Power-Plant-NPDES.aspx.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 22

Comment Excerpt:

7. Bromide should not be regulated through ELGs.

In the 2015 Rule, EPA decided to not regulate the discharge of bromide from steam electric facilities. Instead, EPA allowed for permitting authorities to establish water quality-based effluent limitations on bromide[18]. This allowed for a site-specific approach that enabled state regulatory agencies to address bromides issues only where they exist. For the final ELG Rule, EPA should continue with the same approach as defined in the 2015 Rule and allow states to focus on a site-specific approach. A state-based site-specific approach would also require the regulatory agency to address all inputs of bromides in a problem area, where an ELG based approach would focus only on steam and electric generating facilities. An ELG based approach would not address various other sources of bromide that may exist within a watershed and potentially impact the watershed. Such an approach would put unnecessary burdens on power generating facilities and still not fully address any potential watershed issues. Furthermore, by way of technological advances at power generation facilities, levels of bromine use have significantly decreased over time as water purification and air emission quality controls have been optimized.

[18] Fed. Reg. Vol 80, p. 67838

Commenter Name: David A. Friedman
Commenter Affiliation: FirstEnergy Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8302-A1
Comment Excerpt Number: 19

Comment Excerpt:

Bromides
FirstEnergy supports the Proposed Rule's preferred option to keep bromides as a water quality watershed issue for local agencies and permit writers to respond appropriately; however, the Proposed ELG Rule also requests comments for alternative bromide approaches, all of which, FirstEnergy finds inappropriate and not necessary for the following reasons.

Permit writers are acting on EPA's comments pertaining to bromides in the Proposed Rule. EPA states that it is only aware of a couple of states that are monitoring for bromides. See 84 Fed. Reg. at 64,642. Unfortunately, the statement disregards several intervening circumstances that happened in the permitting process. The 2015 ELG Rule was effective in January 2016, and subsequently placed into reconsideration in April 2017. The ongoing uncertainty surrounding the Steam Electric ELG Rule coupled with the fact that the time between the effective date 2015 ELG Rule and the current Proposed Rule is approximately three and a half years (whereas most permit terms are five years and some are administratively extended) has led to a backlog of permitting decisions for steam electric power plants. FirstEnergy is also aware of ongoing litigation of permits over ELG conditions due to the uncertainty surrounding the Steam Electric ELG Rule that further exacerbates the permitting situation. Where permits have been reissued or proposed, such as in Pennsylvania, bromide monitoring is in the permit.[4]

4 Coal Power Plant NPDES. Pennsylvania Department of Environmental Protection, www.dep.pa.gov/About/Regional/SouthwestRegion/Community Information/Pages/Coal-Power-Plant-NPDES.aspx.

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 5

Comment Excerpt:

If option 4 is not chosen, EPA should pursue a combination of all other available methods

Although option 4 is the most likely rule option to be protective of public health and per EPA's own analysis, provide the greatest health benefits, should EPA pursue another option (as is proposed in this rule), it should take as many steps as possible to reduce the impacts of bromide discharges on downstream drinking water and public health. In addition to bromide being addressed in the VIP program, the proposal discusses the following approaches for facilities not in the VIP program, beginning on page 84 FR 64642:

1. Bromide monitoring under CWA section 308
2. Bromide minimization plans under CWA sections 301(b) and 304(b)
3. A numeric limit under CWA sections 301(b) and 304(b) based on product substitution

Should EPA not use regulatory option 4, it should actively and aggressively pursue both #1 (monitoring) and #2 (minimization plans), which are not mutually exclusive. Although the protection will not be as comprehensive as if option 4 was chosen, a combination of these activities will facilitate achieving similar benefits. The numeric limit based on product substitution should not be pursued.

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 6

Comment Excerpt:

EPA should include monitoring for bromide under CWA section 308, and take measures to ensure accuracy of the data

Beginning on page 84 FR 64643, the proposal discusses the possibility of several potential choices for monitoring bromide discharges. AWWA appreciates that EPA is considering monitoring as a portion of this rule. Although the preferred option is to prevent bromide discharges in the first place, if they are not completely prevented, monitoring will help to provide relevant information to states and utilities to mitigate impacts to public health.

Although the proposal does include monitoring options, the options currently presented are insufficient to meet critical public health needs. All the monitoring options presented are time limited and a small number of samples per year (e.g. 1 sample per month for 2 years). The monitoring is also proposed as either only at the discharge point or at both the intake and the discharge point. This combination of conditions would provide some useful information, but the following would be considerably more useful in protecting public health, and EPA should pursue these options:

- *Include a flue-gas desulfurization (FGD) monitoring point.* Given the high likelihood that much of the input of bromide (as well as opportunity to control it) will be from FGD wastewater, include a monitoring point of FGD wastewater. This will provide both facilities and states the opportunity to better understand where the loads originate, and therefore how to address them.
- *Do not limit the total monitoring period.* This is necessary because bromide loading may change in the absence of an intentional change, as a response to the effectiveness or ineffectiveness of a bromide minimization plan (see below) as well as the resulting concentration impacting downstream utilities may change based upon hydrologic changes not captured in a two-year monitoring period.

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 7

Comment Excerpt:

EPA should pursue bromide minimization plans under CWA sections 301(b) and 304(b), and assure such plans are protective of public health

The creation of bromide minimization plans could be one component of helping to protect public health by reducing bromide discharges, when combined with other tools to help reduce bromide discharges, such as monitoring for effectiveness over time. There are several vital components of such plans, if they are to be effective:

- First, a minimization plan should be reviewed and approved in consultation with the state regulatory agency, assuring that the best available management practices to minimize bromide at that facility are included.
- Second, progress against the plan should be regularly measured and the plan adjusted to address new minimization practices over time. Failing to follow the minimization plan should result in corrective actions.
- Finally, the minimization plan must assure that bromide-based products are not substituted with other products that may present similar or even bigger risks to public health. For example, brominated products should not be substituted with iodinated products, which have similar health concerns.

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 8

Comment Excerpt:

EPA should not pursue a numeric limit under CWA sections 301(b) and 304(b) based on product substitution, unless no other options are available

As currently discussed on page 84 FR 64643, a limit based upon product substitution would only account for the incremental difference between bromide that exists within coal itself and bromide added through coal refining or other processes. Although any reduction in bromide loading into source waters is useful, the origin of the discharged bromide is not relevant for its impacts on public health. Whether the bromide was present in the coal itself, added during refinement, or from some other source, the impacts of the discharge are the same. EPA should focus on measures that reduce bromide loads regardless of the source within the facility, including an overall limit (such as what is currently proposed within the VIP program through membrane filtration), monitoring, and overall minimization.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 8

Comment Excerpt:

NRECA does not see that possible further monitoring or regulation of bromide discharged from steam electric plants is warranted, especially as bromide is properly regulated as a site-specific issue through water quality standards and provisions.

...Where bromide is a concern, address through the local water quality standards program.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 14

Comment Excerpt:

BROMIDE REGULATION SHOULD BE LIMITED TO SITE-SPECIFIC, WATER QUALITY-BASED LIMITATIONS FOR ONLY THOSE FGDWASTEWATER DISCHARGES IMPACTING DOWNSTREAM DRINKING WATER TREATMENT PLANTS.
Oglethorpe Power recommends that EPA retain its current approach to regulating bromides in FGD wastewater under the 2015 Rules. That approach focused on setting water quality-based discharge limitations on a site-specific basis for those coal-fired EGUs that may be releasing bromides at elevated levels and impacting downstream drinking water treatment facilities. This approach is vastly preferable to imposing specific numeric effluent discharge limitations for bromides on all affected facilities based on control technologies, such as thermal evaporation, membrane filtration or reverse osmosis treatment. Imposing such technology-based control requirements on all affected facilities is not necessary to ensure protection of human health and the environment since potential water quality concerns due to bromides are limited to a small number of affected facilities that may be impacting downstream drinking water treatment facilities.[16] The setting of water quality-based effluent standards to address limited site-specific impacts of bromides is clearly authorized by the statute[17] and addressed in detail by EPA's implementing regulations. Notably, federal regulations at 40 C.F.R. §122.44(d)(1) require the permitting authority to include any effluent discharge limitations more stringent than those specified in the ELG Rules that may be necessary to achieve the water quality standards

established under section 303 of CWA. Furthermore, those same federal regulations require that the limitations must control all pollutants (or pollutant parameters) that the permitting authority determines are being discharged from any particular source at levels that "have a reasonable potential to cause, or contribute to an excursion above any state water quality standard, including state narrative for water quality."[18] Based on this regulatory authority, the permitting authorities already have an obligation to evaluate the potential downstream impacts of bromides in FGD wastewater from each affected EGU facility and set site-specific, water quality-based effluent discharge limitations, as appropriate, in those cases in which those FGD wastewater discharges from those facilities may be having potential adverse impacts due to releases of bromides.

If EPA determines that further federal regulation is needed to address the potential risks of the bromides in FGD wastewater releases, Oglethorpe Power recommends that this regulation should be limited to only requiring affected EGU facilities to perform monthly monitoring for a two-year period in order to assess the potential bromide impacts from each facility. Further bromide monitoring after the end of the two-year period should be required only if there are significant changes in facility operations that could alter the bromide concentrations in the FGD wastewater. Such operational changes could include changing to a brominated refined coal, a bromide addition process, a coal feedstock with higher bromide levels, or the use of brominated powered activated carbon for controlling mercury air emissions. Only for those EGU facilities for which the monitoring indicates a potential water quality problem for bromides should there be a requirement to adopt additional control requirements, such as the development and implementation of a site-specific bromide minimization plan or the establishment of numeric discharge limitations based on product substitution or technology-based control measures for reducing bromides from the FGD wastewater. This decision on the bromide control requirements should be made by the permitting authority on a case-by-case basis in light of the nature, scope and extent of the potential bromides risks.

16 84 Fed. Reg. at 64,667.
17 See Sections 303 - 305 of the CWA.
18 84 Fed. Reg. at 64,667.

Commenter Name: Jane H. Hood
Commenter Affiliation: Santee Cooper
Document Control Number: EPA-HQ-OW-2009-0819-8322-A1
Comment Excerpt Number: 11

Comment Excerpt:

IV. BROMIDE REGULATION SHOULD BE LIMITED TO SITE-SPECIFIC, WATER QUALITY-BASED LIMITATIONS FOR ONLY THOSE FGD WASTEWATER DISCHARGES IMPACTING DOWNSTREAM DRINKING WATER TREATMENT PLANTS.

Santee Cooper recommends that EPA retains its current approach on the regulation of bromides in FGD wastewater under the 2015 Rules. That approach focused on setting water quality-based discharge limitations on a site-specific basis for those coal-fired EGUs that may be releasing bromides at elevated levels that are having impacts on downstream drinking water treatment facilities. This approach is vastly preferable to imposing specific numeric effluent discharge limitations for bromides on all affected facilities based on control technologies, such as thermal evaporation, membrane filtration or reverse osmosis treatment. Imposing such technology-based control requirements on all affected facilities is not necessary to ensure protection of human health and the environment given any potential water quality concerns due to bromides is limited to a small number of affected facilities that may be impacting downstream drinking water treatment facilities.[11] The setting of water quality-based effluent standards to address limited site-specific impacts of bromides is clearly authorized by the statute[12] and addressed in detail by EPA's implementing regulations. Notably, federal regulations at 40 C.F.R. §122.44(d)(1) requires the permitting authority to include any effluent discharge limitations more stringent than those specified in the ELG Rules that may be necessary to achieve the water quality standards established under section 303 of CWA. Furthermore, those same federal regulations require that the limitations must control all pollutants (or pollutant parameters) that the permitting authority determines are being discharged from any particular source at levels that "have a reasonable potential to cause, or contribute to an excursion above any state water quality standard, including state narrative for water quality."[13] Based on this regulatory authority, the permitting authorities already have an obligation to evaluate the potential downstream impacts of bromides in FGD wastewater from each affected EGU facility and set site-specific, water quality-based effluent discharge limitations, as appropriate, in those cases in which those FGD wastewater discharges from those facilities may be having potential adverse impacts due to releases of bromides. If EPA determines that further federal regulation is needed to address the potential risks of the bromides in FGD wastewater releases, Santee Cooper recommends that this regulation should be limited to only requiring affected EGU facilities to perform monthly monitoring for a two-year period in order to assess the potential bromide impacts from each facility. Further bromide monitoring after the end of the two-year period should be required only if there are significant changes in facility operations that could alter the bromide concentrations in the FGD wastewater. Such operational changes could include changing to a brominated refined coal, a bromide addition process, a coal feedstock with higher bromide levels, or the use of brominated powered activated carbon for controlling mercury air emissions. Only for those EGU facilities for which the monitoring indicates a potential water quality problem for bromides should there be a requirement to adopt additional control requirements, such as the development and implementation of a site-specific bromide minimization plan or the establishment of numeric discharge limitations based on product substitution or technology-based control measures for reducing bromides from the FGD wastewater. This decision on the bromide control requirements should be made by the permitting authority on a case-by-case basis in light of the nature, scope and extent of the potential bromides risks.

[11] 84 Fed. Reg. at 64,667.
[12] See Sections 303 - 305 of the CWA.
[13] 84 Fed. Reg. at 64,667.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 8

Comment Excerpt:

D. If Included in the ELG Rule Revisions, Bromides Should be Regulated Only on a Case-by-Case Basis.

EPA properly chose not to propose non-voluntary bromide limitations for FGD wastewater, recognizing that there is no technological basis for a bromide limit based on its appropriately selected BAT for FGD wastewater, i.e., chemical precipitation followed by LRTR biological treatment. EPA is, however, considering establishing bromide limits on a voluntary basis under the Volunteer Incentive Program (VIP) for FGD wastewater.[17] To the extent that EPA decides to address bromides in the final rule, CCIG supports EPA's proposal to evaluate bromide limits on a case-by-case basis. However, CCIG urges EPA to adopt an exemption to the evaluation of bromides from discharges to estuarine, marine, or tidally influenced environments given the receiving waters' bromide concentration. Coal-fired stations are not the only source of bromides,[18] and bromides are not the only factor in the formation of of total trihalomethanes (TTHM), meaning that establishing a limitation for bromides on a case-by-case basis is unlikely to completely address the issues that EPA is hoping to target; however, should EPA still choose to address bromides in the final rule, establishing case-by-case limits is more likely to provide the flexibility required to address issues associated with various types of receiving waters.

[17] Proposed Rule, 84 Fed. Reg. at 64,637.
[18] Bromide concentration in these environments is frequently non-anthropogenic, and may be influenced not only by other types of facilities but also natural phenomena. For example, bromide levels in tidally influenced areas can be influenced by saltwater intrusion: during drought conditions, the saltwater wedge and associated elevated bromide concentrations may extend well upstream and affect tidally-influenced bodies of water.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 11

Comment Excerpt:

Based on CCIG's concerns regarding EPA's proposed revisions to sampling provisions for FGD wastewater, the Group also requests that EPA reconsider its focus on bromides and take into account sources outside of the electric power sector in its case-by-case limit determinations. CCIG supports EPA's proposal that a water-quality-based approach to effluent limits is the most appropriate approach when determining how to regulate bromides. But given that factors beyond bromides may contribute to difficulties with maintaining DBR-compliant water quality the Group suggests that EPA use a holistic case-by-case approach at the watershed level that includes evaluation of all sources, not just sources in the electric power sector. In light of these concerns, CCIG proposes that if EPA chooses to address bromides in the final rule the VIP program, discharges to estuarine, marine, and tidally influenced environments should be exempted from any bromide consideration. Due to the non-anthropogenic nature of bromides present in such environments, creating bromide limits for discharges to those environments is unnecessary. Exempting discharges to estuarine, marine, and tidally influenced environments from bromide limits ensures that measures intended to protect drinking water do not sweep in bromide discharges that do not contribute to formation of TTMH in drinking water.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 11

Comment Excerpt:

EPA's suggestions for possible further monitoring or regulation of bromide discharged in FGD wastewater and BATW are not warranted. Bromide is properly regulated as a site-specific issue using water quality standards as a means of control.

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 15

Comment Excerpt:

The final rule should not address bromides outside of the voluntary incentives program.

The proposed rule imposes numeric limits for bromide based on membrane filtration technology, but only as part of the voluntary incentive program.[73] While these limits may be appropriate as incentive for those facilities that choose to install membrane filtration, Cleco agrees with EPA that this technology is far from nationally available, is too costly, and poses difficult questions about non-water quality impacts. [74] It is therefore appropriate for EPA to forego mandatory limitations based on membrane filtration technology.

Beyond the incentives program, however, EPA has also requested comments on three conceptual "sub-options" related to bromides and their impacts on water quality.[75] These include (1) monitoring requirements, (2) a "bromide minimization plan" based on either qualitative or numeric limits, and (3) numeric limits based on product substitution.[76] The Agency should not pursue any of these options at this time. It should instead continue to pursue a water quality based approach to bromides.

The development of effluent limitations guidelines should focus on the types, costs, and availability of current technologies. The guidelines serve as uniform, nationally applicable performance standards that must be met without regard to the quality of receiving waters. [77] To date, the Agency has not developed an evidentiary record around bromide treatment or reduction technology through this framework. What evidence the Agency has developed suggests only that a pruticular type of technology, membrane filtration, is not suitable for a national standard. [78]

[73] See id. at 64,674 (to be codified at 40 C.F.R. § 423.131(g)(i)).
[74] See id at 64,632-34.
[75] See id at 64,642.
[76] Id
[77] See, e.g., EPA, NPDES Permit Writers' Manual § 5.2 (2010).
[78] Other technologies examined by EPA have not been found effective at treating bromides, see, e.g., Supplemental Development Document at 8-5 (chemical precipitation plus biological treatment), or are insufficiently available or economical to justify national standards, see Proposed Rule, 84 Fed. Reg. at 64,634 (evaporation). ·

Commenter Name: Bill Matthews
Commenter Affiliation: Cleco Corporate Holdings LLC
Document Control Number: EPA-HQ-OW-2009-0819-8325-A1
Comment Excerpt Number: 16

Comment Excerpt:

The concerns about bromides described in the preamble are driven not by development of new technology but by concerns about the water quality for certain defined areas. [79] But concerns about water quality should be addressed through locally developed water quality-based effluent limitations, not nationally applicable technology standards. [80] It might be true that only some states have taken measures related to bromides, but that is within their discretion as the stewards of local water quality standards and the local permitting authorities.

None of the three "sub-options" is appropriate to address local water quality concerns. Monitoring should be necessary only where there are genuine concerns about bromides' impact on water quality and associated uses; it should not be imposed on every facility across the nation, even those who have no reason to expect meaningful bromide discharges. Instead, local permitting authorities can impose monitoring conditions where they have cause for further investigation. For EPA's part, it can investigate nascent bromide-related technologies through site visits and other informal means, just as it did with the technologies that ultimately became central to the current rule.

The other two "sub-options" might be equally unjustifiable from a cost perspective. EPA has not explained in sufficient detail what would be entailed by qualitative mandates or numeric limits related to a "minimization plan" or product substitution. Cleco is highly concerned that either avenue might entail switching coal types. Doing so would be enormously costly to Cleco's Dolet Hills facility, which depends on readily available lignite coal sourced from on-site mines. [81] Cleco has no metric in the proposed rule by which to gauge whether EPA considers its current lignite to be "lower-bromide[] coal[,]" as suggested in the brief discussion on bromide minimization plans. [82]

As to product substitution, Cleco does not believe this would be feasible with respect to coal or additives, [83] and it is not clear that even this sort of certification would resolve whatever concerns EPA has received. The facilities most able to certify to this effect are those that have never used bromides and thus are those least likely to be in areas with water quality issues. That would require something else from other facilities. EPA has suggested "numeric limitations that reflects the difference in concentrations naturally occurring in coal" compared to refined coal or applied halogens.[84] But the public has been given none of EPA's thinking on what these differences are, how much variation in bromine naturally occurs, whether that variation is across the major types of coal or particular mines, or other basic questions. This brief suggestion is therefore far too premature to flesh out in a final rule. If EPA does intend to take more specific steps with respect to bromides, it should do so only in a later, separate rulemaking.

[79] See Proposed Rule, 84 Fed. Reg. at 64,629.
[80] See EPA, NPDES Permit Writers' Manual § 6.3.
[81] See, e.g., "Regulated Power Plants," Cleco.com, https://www.cleco.com/-/power-plants ("Dolet Hills burns 3.5-4 million tons of lignite yearly. Because of the proximity of the mine to the plant, the electricity generated is economical and reliable. A seven-mile conveyor belt sends the lignite directly from the mine to the plant, saving on transportation and other costs.").
[82] Proposed Rule, 84 Fed. Reg. at 64,643.
[83] Id.
[84] Id.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 9

Comment Excerpt:

Bromides

- We encourage EPA to continue to delegate regulation of bromide discharges to state and local authorities. At most, EPA should promulgate a list of permissible regulatory options that permitting authorities can consider and choose to impose situationally.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 71

Comment Excerpt:

D. Bromide is Properly Regulated on a Site-specific Basis Rather Than Through a National ELG.

In 2015, EPA decided not to directly regulate discharges of bromide by setting national numeric effluent limitations and standards for existing sources. Bromide itself does not pose any human health concerns; however, EPA found that, at four drinking water treatment facilities, disinfection by-products ("DBPs"), such as total trihalomethanes ("TTHMs"), began forming as a result of interactions with an increased level of bromide in the drinking water treatment facilities' source water. See 80 Fed. Reg. at 67,840. Under the 2015 rule, EPA determined that bromides would be controlled by the New Source Performance Standards, the Pretreatment Standards for New Sources, and by the BAT effluent limitations for existing sources that choose to participate in the voluntary incentives program. See id. at 67,886. Depending on site-specific conditions and applicable state water quality standards, EPA found it may be appropriate for permitting authorities to establish water quality-based effluent limitations on bromide. Id. at 67,886. Thus, instead of setting nationwide standards, EPA left it to permitting authorities to "carefully consider whether water quality-based effluent limitations on bromide or TDS would be appropriate for FGD wastewater discharges from steam electric power plants upstream of drinking water intakes." Id. at 67,886.

UWAG agrees with the approach EPA took in the 2015 rule because national ELGs are not designed to address watershed-level issues, where many sources and variables are in play. The potential impact of bromide discharges on downstream drinking water systems is a very site specific inquiry and will depend on site-specific factors such as existing power plant treatment equipment and mode and timing of operation, size of the receiving waterbody, distance between the power plant and the drinking water intake, and natural constituents already present in the receiving waterbody. Assuming, however, that the bromide reaches the drinking water facility in sufficient quantities, a number of other factors contribute to the development of TTHM:

- the use of chlorine as a disinfectant;
- the concentration of chlorine used in the disinfection process;
- water temperature and pH;
- treated water system residence time; and
- Total Organic Carbon ("TOC") of the source and treated waters.

Accordingly, TTHM formation can be controlled to a degree by removing TOC, managing pH, and taking other steps internal to the drinking water facility—steps that may be more cost-effective, under certain circumstances, than limiting the discharge of bromide upstream. For example, organic build-up in the water supply tank within a drinking water facility can be a significant cause of TTHM formation. The interaction of so many variables— together with the possibility of multiple contributing sources—weigh in favor of a water quality based approach.

Nevertheless, relying in part on flawed research, the American Water Works Association ("AWWA") and the Association of Metropolitan Water Agencies ("AMWA") have called for EPA to modify its approach. In a June 2018 letter, AWWA and AMWA requested that EPA examine the impacts of bromide discharges on downstream water systems and take action to regulate such discharges as part of its reconsideration of the effluent limitations that apply to FGD wastewater.[112] They argued that EPA should impose zero discharge of FGD wastewater because of concerns related to bromide within FGD wastewater discharges.

In response to this letter, the Proposed Rule requests comment on three regulatory options related to bromide in FGD wastewater: (i) a monitoring requirement under CWA § 308, (ii) a bromide minimization plan using narrative or non-numeric limitations under CWA §§ 301(b) and 304(b), or (iii) a numeric limit under CWA §§ 301(b) and 304(b) based on product substitution. 84 Fed. Reg. at 64,642.

Below, UWAG addresses the concerns raised by AWWA and AMWA, evaluates the bromide-related data and analysis that appears in the administrative record, and responds to EPA's requests for comment. In sum, the scientific literature upon which the drinking water utilities (and EPA, in part) rely contains critical flaws. Also, EPA's benefit and cost analysis overestimates the quantity of bromide from coal-fired plants reaching downstream drinking water facilities, assumes a causal connection between TTHM and bladder cancer where significant scientific uncertainty remains, and concludes that the overwhelming majority of bromide-related benefits from the rule come from only a handful of power plants. Thus, none of EPA's proposed regulatory sub-options to address bromide would be sensible.

UWAG encourages EPA to follow the same approach it took in the 2015 Rule. This issue should be left to states and permitting authorities to determine whether water quality-based effluent limitations on bromide or TDS would be appropriate for FGD wastewater discharges from a particular facility. Based on the available data, the issues associated with bromide appear to be site-specific, not nationwide, and the risks associated with increased levels of bromide may be caused by a number of intervening factors, including potential sources of bromide other than FGD wastewater within watersheds. Bromide itself does not constitute an environmental or health hazard,[113] and a new study suggests that the health risks associated with brominated DBPs are uncertain. So the imposition of an unwarranted technology-based standard on a national scale is unjustified in that it would place an unnecessary and significant cost burden on coal-fired power plants (and ultimately their customers).

To the extent there is a problem, applying any of the proposed regulatory sub-options, or imposing zero discharge of FGD wastewater, are not appropriate solutions. There are too many intervening factors (including whether there is a downstream drinking water facility, what operational equipment the drinking water facility has in place, the level of chlorination used by the facility, and the amount of organics and bromide in the intake of the drinking water facility), and the available zero discharge technologies are not feasible or demonstrated. Therefore, UWAG recommends that the potential discharge of bromide (in FGD wastewater) as a water quality issue be best handled—where any problem exists—through holistic water quality measures implemented by state permitting agencies. Not every issue is best addressed through application of national standards, and this is one that should be addressed at the individual plant level.

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[112] AWWA and AMWA, Letter to EPA Re: Steam-Electric Power Plant Effluent Limitations Guidelines Rulemaking and Safe Drinking Water, EPA-HQ-OW-2009-0819-7598 (June 8, 2018).

[113] EPA, *Supplemental Environmental Assessment for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* EPA-821-R-19-010, EPA-HQ-OW-2009-0819-8230 (Nov. 2019) ("Supplemental EA") at 2-4.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)

Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 88

Comment Excerpt:

G. Based on the Limited Threat Posed by Bromide in FGD Wastewater Discharges, EPA's Proposed Nationwide Regulatory Options are Unreasonable.

Furthermore, as EPA notes, several states, including Pennsylvania, Alabama, and North Carolina, already have taken action to conduct bromide monitoring at multiple facilities with FGD wastewater discharges. See 84 Fed. Reg. at 64,642, n.76. Based on the results of these monitoring efforts, permit writers in these states are adding new NPDES permit provisions—when appropriate—to address bromide. By January 1, 2029, based on industry data, it is estimated that 25 units with wet FGD discharges and a capacity of 19,053 MW will be located within Pennsylvania, Alabama, and North Carolina. This will account for roughly 17 percent of all wet FGD discharges in the United States and 24 percent of total generation capacity. Furthermore, ORSANCO, which encompasses eight states (Illinois, Indiana, Kentucky, New York, Ohio, Pennsylvania, Virginia, and West Virginia), monitors bromide levels. Since 2013, ORSANCO has been collecting samples that test for bromide from 29 different locations along the Ohio River and its major tributaries.[160] It is estimated that 35 units with wet FGD discharges will be operational along the Ohio River by January 1, 2029. Thus, along the Ohio River, ORSANCO already has in place efficient monitoring. When combined with the three states that have initiated bromide monitoring (thus far), nearly 50 percent of all wet FGD discharge capacity in 2029 will either be on a river section being monitored for bromide or subject to permit conditions (or being considered for permit conditions) based on bromide.

Given the steps that already have been taken by states to monitor a significant percentage of facilities with FGD wastewater discharges, and the limited threat posed by bromide on human health and the environment, none of EPA's proposed regulatory sub-options are reasonable. EPA requests comment on three nationwide regulatory options: (i) a monitoring requirement, (ii) a bromide minimization plan using narrative or non-numeric limitations, or (iii) a numeric limit. 84 Fed. Reg. at 64,642-43.

EPA requests comment on two possible monitoring scenarios. Under the first, EPA asks whether bromide should be monitored monthly for two years and thereafter only if there are changes in plant operations that could alter bromide concentrations in FGD wastewater. Under the second scenario, EPA asks for comment on whether bromide should be monitored monthly for five years at two locations, one of which would be an intake water sampling point. See id. at 64,643. As noted above, monitoring already occurs in the states and waterbodies where a substantial portion of bromide discharges are most likely. Also, whether bromide discharges within FGD wastewater impact a drinking water utility's intake is a site-specific inquiry that depends on a combination of various factors. Thus, UWAG does not support any uniform nationwide monitoring requirement.

With regard to the second option, EPA asks whether it would be feasible to develop site specific bromide minimization plans using narrative or non-numeric limits. Under this approach, facilities would be able to consider compliance with other regulations, such as MATS, but would otherwise need to minimize bromide by switching to lower-bromide coals, reducing bromide addition, and/or cutting back on refined coal use. Again, it is unnecessary for EPA to implement a nationwide policy that would apply to all coal-fired power plants. Each facility's approach to bromide reduction would be different based on site-specific factors, such as its proximity to a drinking water utility. In addition, EPA's proposal is vague. To what degree would a facility be required to minimize its bromide loadings? Would a facility be required to burn lower-bromide coal even if it required long-distance transportation from a different part of the country or significantly increased the cost of electricity? The proposal, as written, does not provide enough detail for UWAG to adequately comment.

Finally, EPA solicits comments on whether a numeric limit could be established based on differences in bromide concentrations naturally occurring in coal as opposed to levels found in refined coal or from other halogen applications. Like the other two proposals, setting a nationwide numeric limit would be inappropriate in light of the limited threat posed by bromide on human health and the environment and the many site-specific factors that contribute to increased TTHM levels in drinking water. Further, EPA has not provided enough information to allow UWAG to adequately comment on this proposal.

XV. EPA's Proposed Retirement Subcategory is Appropriate and Critical to Supporting Industry Transitions.

When developing ELGs, the CWA requires EPA to consider "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, nonwater quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate." 33 U.S.C. § 1314(b)(2)(B); *see also Am. Iron & Steel Inst. v. EPA,* 526 F.2d 1027, 1048, 1052, 1054 (3rd Cir. 1975), *amended,* 560 F.2d 589 (3rd Cir. 1977), *app. after remand,* 568 F.2d 284 (3rd Cir. 1977) (EPA required to "consider age as it had a bearing on the cost or feasibility of retrofitting plants" and "industry's capability of meeting those costs," including "evidence that many plants cannot raise the necessary capital to finance the installation of anti-pollution devices and would be forced to close").

Based on this legal authority, EPA proposes to establish a subcategory for coal-fired units that have a limited remaining useful life or, in other words, those that certify they will retire by December 31, 2028. 84 Fed. Reg. at 64,640. For this proposed subcategory (the "Retirement Subcategory"), EPA proposes surface impoundments as the technology basis for BAT, and it proposes to establish BAT limitations on TSS for both FGD wastewater and BATW that are equivalent to existing TSS limits.

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[160] See ORSANCO, Bromide, http://www.orsanco.org/data/bromide/ (last visited Dec. 21, 2019).

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy

Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 10

Comment Excerpt:

A Site-Specific Holistic Watershed Approach is the Most Appropriate Approach for Bromides

EPA proposed "a water quality-based approach as the most appropriate approach"[15] to address bromides, and Duke Energy agrees, but recommends including the requirement to evaluate all dischargers of bromide as well as the drinking water treatment system (DWTS) operations. To effectively address the formation of disinfection by-products (DBP) and compliance issues with the maximum contaminant level (MCL) for trihalomethanes (THMs), a holistic approach needs to be taken at the watershed level by evaluating all sources contributing bromides to the source water for the DWTS, as well as other factors contributing to the formation of THMs. If the concentration of bromides or any other water quality constituent in the source water are identified as adversely impacting the DWTS, states can work with the DWTS and upstream dischargers to determine an appropriate in-stream bromide concentration or other water-related constituent to reduce adverse impacts to the DWTS. Appropriate water-quality based limits can be placed on upstream dischargers either thru the NPDES permit or a consent agreement.

Bromide is not in itself toxic and is rarely identified as a pollutant of concern in effluent limitation guidelines. During disinfection of water with chlorine or chloramines and in the presence of natural organic matter, bromide can contribute to the formation of halogenated DBPs such as THMs and haloacetic acids (HAAs), which are regulated by EPA under the Stage 2 Disinfectants and Disinfection Byproducts Rule (DDBP Rule). There is not a one-to-one relationship between the concentration of bromide in the source water and the concentration of DBPs in finished drinking water. The amount of DPBs formed depends on multiple factors – temperature, pH, and bromide and natural organic matter concentration of the source water, chemical disinfectant and dosage as well as residence time in the in the distribution system. In 2014, Greune evaluated three North Carolina DWTSs – Pittsboro, Wilmington and Fayetteville – and found there was not a clear correlation between influent bromide concentration and finished water TTHM concentration.[16] For example, TTHM concentrations at Pittsboro were observed in the 30 µg/L to 60 µg/L range (below the TTHM MCL) even when the source water bromide concentration was approximately 2,000 µg/L.[17] At Fayetteville, TTHM concentrations below 80 ug/L were observed when the bromide concentration was at approximately 250 µg/L, while TTHM concentrations over 80 µg/L were observed when the bromide concentration was much lower in the range of 20 to 50 µg/L.[18] In Wilmington, similar TTHM concentrations were observed even when the bromide concentration varied from approximately 50 µg/L to 100 µg/L.[19] An unclear relationship between bromide and TTHM concentrations has also been reported by Regli et al. (2015) [20] and Cornwell et al. (2018)[21] and several DBP formation models have historically held bromide constant (Liang and Singer, 2003; Chowdhury et al., 2009)[22,23], so there is not a rigorous dataset to establish a nationwide bromide limit solely based on the relationship between bromide concentration in the source water and DBP concentrations in the finish water. A site-specific watershed approach can lead to more effective solutions by addressing site-specific bromide-related challenges and by considering all the relevant site-specific water quality parameters.

Merely focusing on bromides in the source water may not ensure downstream DWTSs will meet the MCL for TTHMs. In many instances, elevated THM levels are attributable to reasons other than bromide, such as over chlorination, natural organic matter concentration and type, source water temperature and increased retention times in storage tanks and distribution piping. Addressing compliance with the DDBP Rule may be more effectively remedied at the DWTS through the utilization of disinfectants other than chlorine (such as ozone, ultraviolet radiation, chlorine dioxide or chloramine), effective removal of natural organic matter from the source water prior to chlorination, and/or providing aeration. For example, Duke Energy worked with the DWTS for the municipalities of Madison and Eden in North Carolina to take steps to minimize the impacts of bromides to their respective drinking water systems (see Attachment C for additional details). Actions taken at Madison and Eden appear to have been effective at decreasing TTHM concentrations. Duke Energy followed the methodology used by EPA, Office of Water to compare TTHM concentrations prior to the scrubber installation at Belews Creek to TTHM concentrations observed in 2016, 2017, and 2018[24] (see Attachment D; Tables 1 and 2). In Madison, TTHM concentrations have decreased approximately 50% compared to pre-scrubber TTHM concentrations. In Eden, TTHM concentrations have decreased approximately 50% since the two years immediately following scrubber installation and DWTS upgrades.

Stations equipped with FGD scrubbers can also act to reduce the discharge of bromides from the operation of FGD scrubbers without the need for additional treatment. As an example, Duke Energy discontinued the refined coal process under §45 of the Internal Revenue Code (Code) in 2015 at Marshall Steam Station. Through discontinuation of this process, TTHM in downstream drinking facilities decreased by approximately 10%-30%. The sum of the three brominated-THMs decreased by approximately 40%-60%. This data was obtained by following the same methodology used by EPA, Office of Water[25] to compare TTHM concentrations during a full year that the refined coal process was being used at Marshall Steam Station to TTHM concentrations after the refined coal process was discontinued. This data is presented in Attachment D Table 3. The need for a station to take action, as those described as Options 2 and 3 under the proposal[26], is only warranted if there are adverse impacts on the downstream DWTS and bromides are identified as the primary causal factor in the formation of TTHM. Some states in the Midwest United States have promulgated regulations for disinfection byproduct control and treatment, including activated carbon. These disinfectant byproduct regulations include source water testing for bromides, alkalinity, total organic carbon, and formation potential for THM and HAAs. As such, these facilities are not expected to be impacted by upstream discharges of bromides.[27]

Additionally, other sources of bromides need to be considered and evaluated in addition to discharges from wet FGD scrubbers. In the North Carolina State University study, the highest bromide concentrations were consistently observed in the Roanoke, Catawba, and Cape Fear watersheds.[28] There are wet FGD scrubber discharges in the Roanoke and Catawba watersheds, but there are none in the Cape Fear watershed. A publicly owned treatment works (POTW) was identified as the source of bromide in the Cape Fear watershed.[29] Further investigations of bromide in these three watersheds revealed POTWs discharging bromide in both the Roanoke and Catawba watersheds and corroborated the source in the Cape Fear watershed identified in 2014.[30] Since not all POTW discharges contain bromide, it is likely that certain industrial discharges to those POTWs contain bromide, which passes through most wastewater treatment processes. In addition, bromide data has been collected as part of EPA's Fourth Unregulated Contaminant Monitoring Rule (UCMR4) which shows that the highest bromide concentrations in North Carolina are found in groundwater near the coast and in the Yadkin and Cape Fear River Basins. There are no FGD scrubbers in the Yadkin or Cape Fear River Basins, so other sources must be contributing bromide to these watersheds. Since there are additional sources of bromide, focusing solely on discharges from FGD scrubbed facilities will potentially fail to resolve issues at some drinking water facilities.

A number of recent publications have evaluated the impact of FGD scrubbers on downstream drinking water quality. The EPRI recently published an in-depth review of five of these articles and found that the impacts on drinking water were overestimated for several reasons.[31] Some assumptions that led the authors of the reviewed articles to overestimate bromide loading to surface waters were related to the bromide content in coal, bromide addition rates for compliance with the Mercury and Air Toxics (MATS) rule/refined coal, and the moisture content of coal. Most notably, bromide loads to surface waters have decreased since the publication of the reviewed articles due to coal-fired power plant retirements and lower capacity factors and reduced additions of bromide for MATS compliance/refined coal in response to lessons learned in the preliminary stages of the technology.

Through a watershed based-approach, states can more effectively address the impacts to DWTS by identifying all sources contributing bromides to the source waters, better understanding how these sources are impacting the downstream DWTS, and, if warranted, establishing regulatory requirements on those sources to effectively reduce the potential impacts of bromides and any other water quality parameter on downstream DWTS. This process has been implemented by the State of South Carolina through the South Carolina Department of Health and Environmental Control (SCDHEC). In 2011, TTHMs were detected above the MCL at three drinking water facilities on the Broad River. Through investigation and in-stream sampling upstream of the drinking water facilities, SCDHEC identified bromides as a contributing factor in the formation of TTHM and further identified discharges from a wastewater treatment plant at an industrial facility as one of the sources of the elevated bromides in the source water. By working with the downstream drinking water facilities and the industrial source, a mutually agreed upon in-stream bromide concentration was established that would not significantly impact the downstream drinking water facilities. Monitoring and reporting requirements were established and the requirements were implemented through a consent agreement (see Attachment E).[32] Additionally, states have acted to collect data on the discharge of bromides from the operation of FGD scrubbers. In North Carolina, the North Carolina Department of Environmental Quality (NCDEQ) is imposing bromide monitoring of the final discharge on Duke Energy operated coal-fired stations that discharge FGD wastewater. Additionally, Indiana Department of Environmental Management (IDEM) has started including bromide monitoring in NPDES permits for coal-fired power plants to gather information on the levels of bromide being discharged at these types of facilities in Indiana. For Duke Energy's Cayuga Generating Station, IDEM acknowledged "there are no surface water-based public water supplies on the Wabash River downstream of this facility, therefore, the presence of bromide in the effluent should not impact any public water supplies", but is still requiring the monitoring for bromides to gather information on the level of bromide present in the discharges from this type of facility.[33]

15 84 Fed. Reg. 64642 (Nov. 22, 2019).

16 Greune, Amber. "Bromide Occurrence in North Carolina and the Relationship between Bromide Concentration and Brominated Trihalomethane Formation." (Master's thesis). North Carolina State University, Raleigh, NC. (2014) Available online:
https://repository.lib.ncsu.edu/bitstream/handle/1840.16/10000/etd.pdf?sequence=2&isAllowed=y
17 Greune, Amber. "Bromide Occurrence in North Carolina and the Relationship between Bromide Concentration and Brominated Trihalomethane Formation." (Master's thesis). North Carolina State University, Raleigh, NC, (2014), at 93. Available online:
https://repository.lib.ncsu.edu/bitstream/handle/1840.16/10000/etd.pdf?sequence=2&isAllowed=y
18 Id. at p. 94
19 Id.
20 Regli, S, et al. "Estimating Potential Increased Bladder Cancer Risk Due to Increased Bromide Concentrations in Sources of Disinfected Drinking Waters." Environ Sci Technol. 49 (November 2017), at 13094-13102.
21 Cornwell, David A., et al. "Modeling Bromide River Transport and Bromide Impacts on Disinfection Byproducts." Journal of the American Water Works Association 110.11 (October 2018), at E1-E23.
22 Liang, Lin and Philip C. Singer. "Factors Influencing the Formation and Relative Distribution of Haloacetic Acids and Trihalomethanes in Drinking Water." Environ. Sci. Technol. 37.13 (May 2003), at 2920-2928. 23 Chowdhury, S, P Champagne and PJ McLellan. "Models for predicting disinfection byproduct (DBP) formation in drinking waters: a chronological review." Sci Total Environ 407.14 (July 2009), at 4189-4206. 24 Id.
23 Chowdhury, S, P Champagne and PJ McLellan. "Models for predicting disinfection byproduct (DBP) formation in drinking waters: a chronological review." Sci Total Environ 407.14 (July 2009), at 4189-4206.
24 Id.
25 U.S. Envt'l Prot. Agency, Office of Water Memorandum, "Case studies of changes in total trihalomethanes concentrations in treated water from public water systems downstream of steam electric power plants." October 28, 2019.
26 84 Fed. Reg. 64642 (Nov. 22, 2019).
27 Missouri Department of Natural Resources. "Minimum Design Standards for Missouri Community Water Systems." December 2013. Available online: https://dnr.mo.gov/pubs/pub2489.pdf.
28 Greune, Amber. "Bromide Occurrence in North Carolina and the Relationship between Bromide Concentration and Brominated Trihalomethane Formation." (Master's thesis). North Carolina State University, Raleigh, NC, (2014), at 93. Available online:
https://repository.lib.ncsu.edu/bitstream/handle/1840.16/10000/etd.pdf?sequence=2&isAllowed=y
29 Id.
30 Greune, Amber. "Assessment of Bromide in Three North Carolina Watersheds." Journal of the American Water Works Association 111.12 (December 2019), at 34-43.
31 Electric Power Research Institute. "Impacts of Bromide from Power Plants on Downstream Disinfection Byproduct Formation: A Literature Review." 3002017477. November 2019.
32 Consent Agreement between State of South Carolina and Milliken & Company Magnolia Plant. Consent Agreement 12-018-W. May 17, 2012.
33 Indiana Department of Environmental Management. Cayuga Generating Station. NPDES Permit No. IN0002763. July 2018.

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 11

Comment Excerpt:

Regulation of Bromides in FGD Wastewater Discharges

America's Power supports EPA's proposal to retain its current approach to regulating bromides in FGD wastewater under the 2015 rule. That regulatory approach focused on setting water quality-based discharge limitations on a site-specific basis for only those coal-fired generating facilities that may be releasing bromides in FGD wastewater at elevated levels and potentially impacting downstream drinking water treatment facilities.

This approach makes good policy and economic sense given that only a small subset of affected generating units with FGD scrubbers may have bromide levels that would warrant installation of expensive control technologies, such as thermal evaporation, membrane filtration, or reverse osmosis treatment. Under this approach, the imposition of costly technology-based bromide control requirements would be limited to only those affected facilities for which bromide regulation is necessary to address potential water quality concerns. By contrast, it would avoid imposing such expensive controls on those affected generating facilities that are not impacting downstream drinking water treatment facilities and, as a result, bromide regulation is not necessary to ensure protection of human health and the environment.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 6

Comment Excerpt:

- APPA supports the water quality approach EPA has proposed regarding bromide.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 23

Comment Excerpt:

X. BROMIDE IS PROPERLY REGULATED ON A SITE-SPECIFIC BASIS

In the 2015 Rule, EPA established a VIP that provided facilities until December 31, 2023 to implement new BAT limitations if they adopted additional process changes and controls that achieve limits on mercury, arsenic, selenium, and TDS in FGD wastewater based on thermal evaporation technology. However, the 2015 Rule rejected thermal evaporation technology as the basis for BAT and did not establish limitations for bromides in FGD wastewater. In the 2015 Rule preamble, EPA suggested that water quality-based effluent limitations may be appropriate on a site-specific basis to address potential impacts of bromides on drinking water treatment facilities, as determined by state permitting authorities.

Since the 2015 Rule, EPA has conducted studies, obtained data, and met with companies on various issues, including the use of bromide and the effects of bromide discharges from steam electric facilities on drinking water treatment processes. EPA concluded that decisions to install thermal systems, which are more expensive, were driven by water quality-based effluent limits in a facility's National Pollutant Discharge Elimination Standards (NPDES) permit. Based on this new information, EPA is now proposing to revise the VIP limitations to use membrane filtration technology instead of thermal technology and retain the 2015 Rule's approach of leaving bromides to be limited by permitting authorities, where appropriate, using water quality-based effluent limitations. EPA's rationale for this change is due to the higher costs of thermal technology and its ability to consider costs pursuant to section 304(b) of the CWA.

APPA supports EPA's water quality approach to dealing with bromides. Bromide discharges and any impact they may have on drinking water systems is a site-specific inquiry, based on site-specific factors such as existing power plant treatment equipment and mode and timing of operation, size of the receiving waterbody, distance between the power plant and drinking water intake and natural constituents already present in the receiving waterbody.

Assuming, however, that the bromide reaches the drinking water facility in enough quantities, a number of other factors contribute to the development of disinfection by-products (DBPs), such as total trihalomethanes (TTHM). Those factors include:

- the use of chlorine as a disinfectant;
- the concentration of chlorine used in the disinfection process;
- water temperature and pH;
- treated water system residence time; and
- Total Organic Carbon (TOC) of the source and treated waters.

Accordingly, TTHM formation can be controlled to a degree by removing TOC, managing Ph, and taking other steps internal to the drinking water facility—steps that may be more cost-effective, under certain circumstances, than limiting the discharge of bromide upstream. For example, organic build-up in the water supply tank within a drinking water facility can be a significant cause of TTHM formation. The interaction of so many variables— together with the possibility of multiple contributing sources—weigh in favor of a water quality-based approach.

Under the 2015 rule, EPA determined that bromides would be controlled by the New Source Performance Standards, the Pretreatment Standards for New Sources, and by the BAT effluent limitations for existing sources that choose to participate in the voluntary incentives program.[58] Depending on site-specific conditions and applicable state water quality standards, EPA found it may be appropriate for permitting authorities to establish water quality-based effluent limitations on bromide.[59] Thus, instead of setting nationwide standards, EPA left it to permitting authorities to "carefully consider whether water quality-based effluent limitations on bromide or [total dissolved solids (TDS)] would be appropriate for FGD wastewater discharges from steam electric power plants upstream of drinking water intakes." [60] Nonetheless, the American Water Works Association (AWWA) and the Association of Metropolitan Water Agencies (AMWA) requested that EPA examine the impacts of bromide discharges on downstream water systems and take action to regulate such discharges as part of its reconsideration of the effluent limitations that apply to FGD wastewater.61 They argued that EPA should impose zero discharge of FGD wastewater because of concerns related to bromide within FGD wastewater discharges and that bromide discharges will increase absent CWA controls.

There are many coal-fired power plants retiring and the remaining coal fleet experiences less frequent dispatch. According to EPA's records, at least 78 plants (160 units) will be retiring or converting to non-coal fuels between the summer of 2014 and December 31, 2028.[62] These numbers have been verified by information directly from the plant operating company or a government entity.[63] Furthermore, coal consumption for U.S. electricity generation has declined by 26 percent from 2013 to 2018 and will continue to decline as coal-fired power plants close. In addition, plants that continue to operate have already added scrubbers to comply with the Mercury Air Toxic Standards (MATS) rule and other Clean Air Act requirements. As a result, there are very few new wet FGDs that will be added to existing coal-fired plants. Thus, the amount of bromide discharged to surface waters is likely to decrease over time as the use of coal to generate electricity also decreases.

The Proposed Rule requests comment on three regulatory options related to bromide in FGD wastewater: (i) a monitoring requirement under CWA § 308, (ii) a bromide minimization plan using narrative or non-numeric limitations under CWA §§ 301(b) and 304(b), or (iii) a numeric limit under CWA §§ 301(b) and 304(b) based on product substitution.[64]

Monitoring already occurs in the states and waterbodies where a substantial portion of bromide discharges are most likely. Several states including Pennsylvania, Alabama, and North Carolina conduct bromide monitoring at multiple facilities with FGD discharges.[65] Permit writers in these states are adding new NPDES permit provisions—when appropriate—to limit bromide. Furthermore, the Ohio River Valley Water Sanitation Commission (ORSANCO), which encompasses eight states (Illinois, Indiana, Kentucky, New York, Ohio, Pennsylvania, Virginia, and West Virginia), also monitors bromide levels. The ORSANCO states and the three additional state represent 50 percent of all wet FGD discharge capacity in 2029 that will either be on a river section being monitored for bromide or subject to permit conditions (or being considered for permit conditions) based on bromide.

Under the second option, EPA asks whether it would be feasible to develop site-specific bromide minimization plans using narrative or non-numeric limits. Under this approach, facilities would be able to consider compliance with other regulations, such as Mercury Air Toxic Standards rule, but would otherwise need to minimize bromide by switching to lower bromide coals, reducing bromide addition, and/or cutting back on refined coal use. APPA believes it is unnecessary for EPA to implement a nationwide policy that would apply to all coalfired power plants. Each facility's approach to bromide reduction would be different based on site-specific factors, such as its proximity to a drinking water utility. Further, EPA's proposal is vague, and unclear as to how much a facility would be required to minimize its bromide loadings. Would a facility be required to burn lower-bromide coal even if it required long distance transportation from a different part of the country or significantly increased the cost of electricity? As written, the proposal does not provide enough detail to adequately comment.

Finally, EPA solicits comments on whether a numeric limit based on product substitutions. Similar to the other two proposals, setting a nationwide numeric limit would be inappropriate in light of the limited threat posed by bromide on human health and the environment and the many site-specific factors that contribute to increased TTHM levels in drinking water. Further, EPA has not provided enough information to adequately comment on this proposal. Thus, APPA does not support any uniform nationwide monitoring requirement. Bromide monitoring should be left to the discretion of the local permitting authority using state water quality-based effluent limitations. Developing a national standard for this issue would be unreasonable, as any potential impact would be limited to a small number of facilities and any downstream communities.

58 See 80 Fed. Reg. at 67,886.
59 Id.
60 Id.
61 AWWA and AMWA Letter to EPA Re: ELGs for Steam-Electric Power Plants at 1 (June 8, 2018); see also 84 Fed. Reg. at 64,642 (citing AWWA letter).
62 EPA, Supplemental TDD, at 3-2 to 3-3.
63 ERG, Memorandum re: Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule – DCN SE07207, EPA-HQ-OW-2009-0819-7373 ("ERG 2019 Industry Change Memo"), at 2 (July 31, 2019).
64 84 Fed. Reg. at 64,642.
65 84 Fed. Reg. at 64,642 n. 76.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 21

Comment Excerpt:

TVA believes that EPA's water quality-based approach to address bromide is prudent. While bromide may be present in wet FGD wastewater discharges, that is not the only anthropogenic or natural source.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 22

Comment Excerpt:

TVA supports EPA's monitoring-only option for bromide in wet FGD site discharges as it is a site-specific issue, and there are insufficient data to determine the extent of the issue. This monitoring should be for a defined period instead of setting monitoring at two years and thereafter when changes occur that could impact bromide discharges. TVA believes that there is a potential to miss monitoring for coal switches or coal mine differences that could cause discharges of bromide to increase or decrease. TVA believes it is important to also include monitoring of the intake without the influence of plant discharges to characterize background concentrations.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 46

Comment Excerpt:

VIII. THE FINAL RULE SHOULD NOT ADDRESS BROMIDES

EPA should not attempt to regulate bromides in this rulemaking. Technologies that effectively treat and eliminate bromide discharges have not been demonstrated, and much research remains to be done before determining whether these technologies are technologically feasible or economically achievable for treating FGD wastewater.. Moreover, national ELGs are not the proper regulatory mechanism for addressing issues affecting a small subset of watersheds. The water quality-based approach currently employed by states—as needed—is effectively addressing whatever isolated bromide issues may exist. Despite this, if EPA is determined to address bromides in this rulemaking, it should refrain from establishing obligations for the entire industry. To do so would not be the best use of finite resources. EPA should at most promulgate a list of permissible regulatory options permitting authorities can consider and choose to impose situationally.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 47

Comment Excerpt:

A. Mandatory Monitoring is Not Appropriate.

EPA specifically sought comment on two proposed approaches to monitoring FGD wastewater.[107] Neither approach is advisable. Mandating effluent monitoring from a single industry will not provide the data EPA needs to comprehensively analyze bromides in the environment. Other factors, such as operations of drinking water facilities, have the potential to impact what effect—if any—bromides can have in the environment, and EPA needs to more fully understand the totality of variables prior to requiring extensive data collection by the industry. A better foundational understanding of the issues would allow EPA to more narrowly tailor any effluent monitoring that may be necessary or perhaps altogether eliminate the need for it.

Notably, EPA and permitting authorities already possess the ability to require permittees to collect additional monitoring of influent and/or effluent, pursuant to the CWA and/or conforming state statutes. Thus, unless EPA intends to mandate a uniform monitoring program, there is no need to address this issue by regulation. At most, EPA should set out in the preamble to the final rule that additional monitoring is an option to address bromides. But the agency should leave it to the states to develop facility- or watershed-specific monitoring plans in appropriate situations.

107 See id. at 64,643.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 48

Comment Excerpt:

B. A Mandatory Minimization Plan is Not Appropriate.

EPA seeks comment on whether facilities should be required to develop site-specific bromide minimization plans.[108] This proposed option is not necessary and not advisable. Bromide is naturally occurring in coal, and, due to long-term supply contracts, facilities typically do not enjoy an ability to overhaul their fuel feedstock. Bromide concentrations in the same type of coal can also vary a great deal, particularly across seams.[109] Accordingly, there is no meaningful opportunity for minimization on this front.

Southern Company system facilities adding bromides or bromide-containing substances into their processes are only doing so to the extent necessary to comply with other EPA standards—namely the Mercury and Air Toxics Standard (“MATS”) rule, promulgated pursuant to the Clean Air Act. Bromides and bromide-containing substances are costly. These facilities are therefore already incentivized to minimize use of the products. Lastly, a requirement to “minimize” is necessarily subjective and could be applied disparately across the industry. Subjective standards such as this invite second-guessing and pose litigation risks that could be avoided by a more narrowly tailored or focused standard. EPA should at most set out in the preamble to the final rule that permitting authorities could engage permittees to determine whether opportunities exist to reduce usage and/or discharges of bromides.

108 Id.
109 See generally U.S. Geological Serv., COALQUAL DATABASE, https://ncrdspublic.er.usgs.gov/coalqual/.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.

Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 72

Comment Excerpt:

1. Water Quality-Based, Site-Specific Approach to Addressing Bromide Discharges is Insufficient

As it did in the 2015 rule, EPA is proposing "a water quality-based approach as the most appropriate approach" for addressing "the potential impacts of bromides on downstream drinking water treatment facilities, as determined by state permitting authorities."[265] Yet, EPA acknowledges that since 2015 it is only aware that Pennsylvania, Alabama, and North Carolina have required monitoring of bromide discharges, and it is unaware of how many states (if any) have "acted to address such discharges."[266] This lack of state action demonstrates that most states lack the resources and data necessary to establish water quality-based effluent limits (WQBELs) on a site-specific basis. Given competing demands and limited resources, it is unlikely that states will prioritize requiring limits on bromide discharges on a site-specific basis in the future.

A recent example from Maryland underscores the reluctance states have to require site-specific limits on bromide discharges. In July 2018, the Maryland Department of the Environment (MDE) determined that monthly bromide monitoring would be required at the Dickerson Generating Station after several water utilities that draw their supply from the Potomac River expressed their concerns about bromide discharges coming from Dickerson.[267] In addition to urging MDE to require bromide monitoring, the utilities wrote, "Clean Water Act program requirements must ensure that the pollutant load of bromide is controlled at the source because it cannot be removed at downstream treatment plants. Limits need to control discharges to concentrations of bromide equal to background levels currently found in the Potomac River."[268] In its response to the public comments letter, MDE acknowledged the drinking water utilities' concern but stopped short of requiring bromide limits because "there is currently no water quality standard in Maryland for bromides and data collected for Dickerson's discharge is very limited with regards to bromide."[269]

EPA has a responsibility under Section 1311(b)(2)(A) to regulate pollutants found in steam electric power plant wastestreams and should not assume state permit writers have the resources to effectively control bromide discharges through WQBELs alone. Moreover, because bromide is non-reactive in water, power plant bromide discharges can have a cumulative impact on downstream surface waters in multiple states – well beyond just the sub-watersheds where bromides are discharged.[270] Given the interstate nature of these pollution discharges, enforceable, national technology-based standards to limit bromide discharges are most appropriate.

[265] 84 Fed. Reg. at 64,642.
[266] Id.
[267] Maryland Department of the Environment, Response to Public Comments Regarding Dickerson Generating Station, State Discharge Permit Application No. 14-DP-0048, NPDES Permit No. MD002640 at 16-20 (July 25, 2018) (attached).
[268] Id. at 16.
[269] Id. at 19.

[270] K.D. Good & J.M. VanBriesen, Coal-Fired Power Plant Wet Flue Gas Desulfurization Bromide Discharges to U.S. Watersheds and Their Contributions To Drinking Water Sources, 53 Envt'l Sci. & Tech. 213, 223 (2019), DCN SE08117, Docket ID No. EPA-HQ-OW-2009-0819-7888.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 73

Comment Excerpt:

2. The Three Proposed "Sub-Options" for Addressing Bromide Discharges Are Inadequate

None of the three proposed bromide "sub-options," even if all were required collectively, are adequate to deal with this pollution and fail to address the full scope of the problem. Both bromide monitoring and the minimization of bromide should be required – but in addition to, and not instead of, enforceable bromide limits in FGD wastewater discharges.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 74

Comment Excerpt:

a. Bromide Monitoring

Monthly monitoring of bromide concentrations to more accurately characterize power plant discharges is critical and should be required in addition to, and not in place of, requiring bromide limits in FGD wastewater. Unfortunately, the two bromide monitoring options proposed by EPA are insufficient because they are time-limited (i.e., would require only two or five years of monthly monitoring). EPA should not artificially limit the total bromide monitoring period. Two years of monthly monitoring is not sufficient for understanding long-term bromide loadings and seasonal variability. Instead, at a minimum, plants should be required to collect monthly samples at all outfall points that are known to contain bromide. Plants should also be required to collect a monthly sample at enough distance upstream of any outfalls containing bromide (e.g., a mile upstream) to better capture what true bromide background levels are in each receiving water. This monthly monitoring data collected at multiple locations should be made available to downstream drinking water utilities so they can better understanding bromide concentration trends that have the potential to impact treatment options and human health.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 75

Comment Excerpt:

b. Bromide Minimization Plans

Plans to reduce a facility's use of bromide on a site-specific basis could be a useful part of a larger, comprehensive plan to address bromide discharges but would not eliminate the need for monthly monitoring and enforceable bromide limits. Because all coal contains some level of bromide and because even low concentrations of bromide in source water can create treatment challenges for drinking water systems, minimizing the use of bromide and/or switching coal types alone may not be enough to adequately reduce risks to human health. Should EPA pursue this option, it is essential that facilities be required to continue to monitor bromide concentrations monthly to track the effectiveness of any bromide minimization plan over time. Any minimization plan should also be created in consultation with state or federal permit writers and downstream drinking water utilities to ensure that each facility pursues a plan that would result in the greatest possible reduction of bromide. EPA should prohibit the use of any additive substitutes for bromide, such as additives containing iodide or other halides, that could result in similar or greater challenges to drinking water treatment and, therefore, greater risk to human health.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 76

Comment Excerpt:

c. Bromide Limits Based on Product Substitution

As discussed above, because bromide is naturally present in coal, eliminating bromide as an additive or switching coal type is not an effective substitute for enforceable bromide limits in power plant FGD discharges. Under this option as described by EPA, a bromide limit based on product substitution would only account for the incremental "difference in concentrations naturally occurring in coal as opposed to levels of found in refined coal or from other halogen applications."[271] As EPA's recent analysis of bromide concentrations in untreated FGD wastewater revealed, coal plants that do not burn refined coal or use bromide as an additive have average bromide concentrations of 59.1 mg/L, which are well above estimated average background levels in fresh surface waters.[272] As discussed in an earlier section of these comments, a recent study estimated that a 0.05 mg/L increase in raw water bromide concentrations could result in a lifetime excess bladder cancer risk of up to one in 1,000.[273]

Instead of developing a numeric limit based on product substitution, EPA should require a limit on bromide concentrations in FGD wastewater and, indeed, should prohibit bromide discharges in FGD wastewater, given that the truly Best Available Technology, membrane filtration, would eliminate bromide entirely, such as under proposed Option 4 (i.e., membranes at BAT for FGD wastewater).

[271] 84 Fed. Reg. at 64,643.
[272] ERG, Mass Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants – DCN SE07260, Docket ID. No. EPA-HQ-OW-2009-0819-8242 (Oct. 2019).
[273] S. Regli et al. (2015).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 76

Comment Excerpt:

EPA asked for comment on various "sub-options" to control bromide. We support these requirements as a bare-minimum improvement over EPA's previous inaction on bromides, but EPA cannot stop there. Although it is important to monitor discharges, encourage reducing bromide use at plants, and set numerical limits based on product substitution, those measures are not enough, as described in more detail below. EPA must do more to protect public health and comply with the Clean Water Act: it must set enforceable, numeric, effluent limitations based on the best available technology.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 79

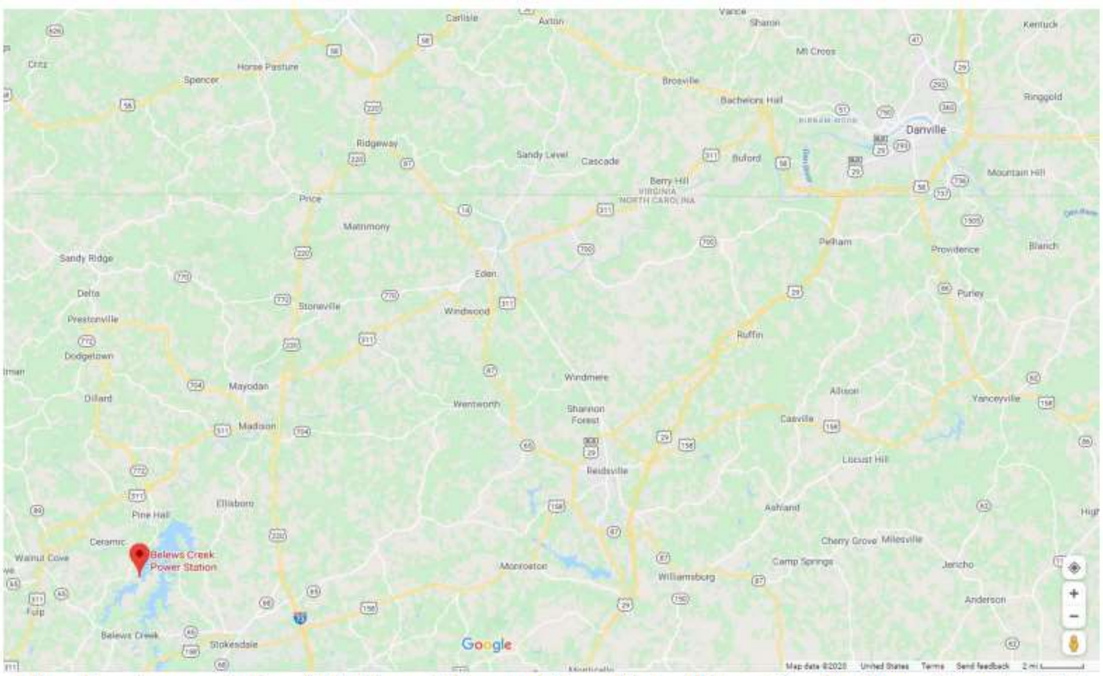
Comment Excerpt:

a. Experience in North Carolina and Virginia illustrates why EPA's proposed sub-options are not enough.

Bromide contamination has been a serious issue for communities in North Carolina and Virginia downstream from Duke Energy's Belews Creek facility, which sits on the Dan River in Stokes County, NC, near the Virginia border.[268] Shortly after Duke Energy installed FGD scrubbers at the plant, the town of Eden observed increased levels of trihalomethanes in its treated drinking water.[269]

As a result of water testing, Eden confirmed in 2011 that Belews Creek was the source of bromide, and internal documents reveal Duke Energy agreed that the FGD system at Belews Creek was likely the source. Thereafter, high levels of trihalomethanes were observed in Madison, NC, which is on the Dan River, closer to Belews Creek than Eden, and the Henry County, VA and Dan River Water utilities, which both purchase water from Eden, NC. Madison, Henry County, VA, and Dan River Water all received notices of violation for unsafe levels of trihalomethanes.

In conjunction with its criminal plea agreement and in subsequent testimony, Duke Energy admitted that its bromide discharges from its FGD wastewater at its Belews Creek site into the Dan River contributed to trihalomethane formation in downstream water systems, including the drinking water systems for Madison and Eden, North Carolina.[270] Rather than eliminate its bromide discharges, Duke Energy entered into agreements with the towns of Eden and Madison to assist them in modifying their drinking water treatment systems to address the trihalomethanes at the backend. Sampling from 2017 shows Duke Energy continued to discharge bromide into Little Belews Creek, a tributary of the Dan River.[271]



Map showing proximity of Madison, Eden, and Danville to Belews Creek. Henry County, VA is adjacent to the VA-NC state line, above Eden, NC. Dan River Water provides water in Rockingham County, NC, where Madison and Eden are located.

NC DEQ implemented measures similar to those EPA proposes now as "sub-options:" it revised Duke Energy's NPDES permit to include additional monitoring and bromide reduction planning requirements for bromide, and after community pressure it also revised Duke Energy's air permit to prohibit the use of brominated additives. Although these were good steps toward controlling bromide pollution in NC, persistent detection of trihalomethanes downstream demonstrates that these measures are not enough to abate the serious public health risk posed by discharging bromides.

[268] Bertrand Gutierrez, Madison and Eden continue costly search for cleaner drinking water, GREENSBORO NEWS & RECORD (Mar. 19, 2017), available at https://www.greensboro.com/news/local_news/madison-and-eden-continuecostly-search-for-cleaner-drinking-water/article_deb43a91-9463-5c8f-a5df-d230ce708b32.html (Attachment 74); Bertrand Gutierrez, Discharge from Belews Creek power plant affects water quality, WINSTON-SALEM JOURNAL (Apr. 13, 2014), available at https://www.journalnow.com/news/local/discharge-from-belews-creek-power-plantaffects-water-quality/article_8e6f8202-a305-580d-a389-d96da37d5629.html (Attachment 75).

[269] Joint Factual Statement, *United States v. Duke Energy*, No. 5:15-CR-62-H, ¶¶ 162-184 (May 14, 2015) (Attachment 76) ("Duke Energy Joint Factual Statement").

[270] Duke Energy Joint Factual Statement, Attachment 76; Duke Energy 30(b)(6) Testimony of Zachary Hall at 38:21-25 (Attachment 77).

[271] Pace Analytical Sampling Results (Jan. 11, 2017) (Attachment 78).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 80

Comment Excerpt:

1. Monitoring and bromide minimization plans alone are not enough to address bromide discharges.

Monitoring and bromide minimization plans are important measures for EPA to require, but EPA must not rely on these alone to control bromide pollution because these procedural requirements by themselves have proven completely ineffective in North Carolina. Duke Energy knew it was discharging bromide into the Dan River, which is a public drinking water source, yet it did nothing to address the problem until the downstream community recognized the problem and Duke Energy faced criminal charges. By that time, Duke Energy had been discharging bromide without limit into the Dan River for years, and it took several more years until the downstream drinking water utilities were able take action to address the problem.

Even with the new drinking water treatment technology and additional monitoring and reporting requirements, elevated levels of trihalomethane continue to be found in the water.[272] Moreover, Duke Energy's efforts are unproductive. Semi-annually, Duke Energy provides a "progress" report on bromide reductions to NC DEQ, which is so devoid of detail that it is impossible to tell what "progress," if any, has been made in minimizing discharge of bromide.[273] Duke Energy's required semiannual bromide reduction reporting illustrates why EPA's suboption is inadequate by itself—this type of reporting without actual obligations to reduce pollution fails to achieve much aside from paperwork.

Instead of simply requiring monitoring or non-numeric bromide minimization plans, EPA must require plants to eliminate bromide discharges by setting effluent limitations based on membrane filtration as BAT. In addition, EPA's monitoring and reporting requirements must call for reporting of more detailed information, including sampling results, so that regulators, downstream drinking water utilities, and the public can better understand the extent of the bromide discharge and take action as needed.

[272] David Cornwell, Expert Report Re: Duke Energy Carolinas Belews Creek Steam Station, 22 (April 8, 2019) (Attachment 79).
[273] See letter from Duke Energy to NC DEQ (May 15, 2019) (Attachment 80).

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 81

Comment Excerpt:

2. Reducing brominated additives is an important step but will not fully eliminate bromide discharges.

EPA's proposed sub-options related to brominated additives also are important first steps for controlling bromide pollution because states often cannot be relied upon to impose appropriate controls on bromide through water quality-based effluent limitations, as EPA has recognized, and states have also failed to reliably control bromide pollution through air permits. However, product substitution only addresses one part of the bromide pollution problem, and only numeric effluent limitations based on BAT can fully protect communities against harm to their drinking water supplies.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 83

Comment Excerpt:

Although eliminating the use of brominated additives is important, as seen in North Carolina, simply eliminating them does not fully address the problem. Duke Energy no longer uses halide salts at Belews Creek, but it still discharges enough bromide to cause serious issues downstream. The best solution is for EPA to eliminate bromide discharge by creating strong effluent limitations based on membrane filtration technology.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 23

Comment Excerpt:

(iv) ZLD would obviate the need to separately consider bromides in the FGD wastewater effluent. EPA does not provide a numerical bromide standard for FGD wastewater as part of its proposed Option 2 despite its recognition that bromine-based compounds are now widely used in coal-fired power plants for control of mercury air emissions, something that was less common in the 2009 time frame when the 2015 ELG rule development began, and despite EPA's recognition that bromide discharges cause adverse health impacts. If EPA chooses not to define BAT as being ZLD for FGD wastewater, it must address bromide as a separate pollutant of concern in FGD effluent.[54] Since the current proposal provides little analysis for this (other than recognizing the presence of bromide in FGD wastewaters), EPA needs to supplement its proposed rule. In any case, ZLD is clearly BAT and adopting a zero-discharge standard would obviate the need for an analysis of bromide loads.

54 EPA does include bromide in the Voluntary Incentives Program (VIP) but that is not sufficient because it leaves bromide discharges from the majority of plants unaddressed

37 <u>Regulatory Implementation – Other</u>

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 25

Comment Excerpt:

3.5 **Use of EPA-supported water quality trading for nitrate/nitrite limit**

For the past decade, EPRI has spearheaded a water quality trading initiative in the Ohio River Basin in collaboration with EPA Regions 3, 4, and 5, the U.S. Department of Agriculture, the States of Ohio, Indiana and Kentucky, and a broad range of local stakeholders, including soil and water conservation districts, farmers, environmental groups, municipalities, industries and the electric power sector. The efforts resulted in the creation of the world's largest water quality trading (WQT) program (<u>http://wqt.epri.com</u>) and a multitude of technical reports, scientific peer-reviewed papers, the United States Water Prize (2015), and the active participation of farmers.

EPRI recognizes EPA's strong leadership on water quality trading, for its sustained commitment to the 2003 national water quality trading policy, and for its recent efforts to modernize and expand the implementation of trading and other market-based mechanisms to achieve additional water quality improvements. However, EPRI notes that recent EPA policies under ELG do not compliment EPA's efforts to incentivize water quality trading. Under its 2003 water quality trading policy, EPA does not support trading to comply with technology-based effluent limitations (TBEL) *in the absence of specific authorization*. As a result, EPA will need to explicitly authorize water quality trading to meet such limitations in connection with future ELG rulemakings. Moreover, by providing explicit authorization, EPA will not only drive innovation beyond conventional treatment technologies but also promote voluntary local partnerships between point and nonpoint sources and promote ancillary environmental benefits such as carbon sinks, flood retention, riparian improvement and habitat. If a facility elects to address limits in a manner that does not result in corresponding nitrate/nitrite reductions (such as using emerging technologies), then WQT could be an effective compliance option for meeting a nitrate/nitrite limit.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 5

Comment Excerpt:

C. EPA should allow BATW reuse in any part of the FGD system.

The 2015 Rule allowed for the discharge of BATW to an FGD absorber provided it is treated to the proposed FGD WW limits prior to discharge to the environment. This discharge was viewed as a discharge option within the 2015 Rule as it allowed for closed loop BATW systems an opportunity to discharge, but the language specifically stated that the discharge needed to be to the FGD absorber. In the 2019 proposal, EPA has kept this discharge option for high recycle rate BATW systems. In the final rule, EPA should amend this option to allow for the discharge of BATW to any part of the FGD WW system if it is prior to any FGD WW treatment components and that the discharge will be treated and ultimately meet final FGD WW limits (See also 3(C)(i) below). This flexibility to discharge prior to any part of the FGD WW treatment system will reduce operational concerns within the FGD absorber, such as aluminium fluoride blinding, and allow better control over the potential for poor gypsum quality. Since all water from the FGD WW treatment system will need to ultimately meet proposed FGD WW discharge standards, the location of a BATW discharge in the FGD WW system should not matter.

Commenter Name: Matthew Goddard
Commenter Affiliation: DTE Energy (DTE)
Document Control Number: EPA-HQ-OW-2009-0819-8316-A1
Comment Excerpt Number: 6

Comment Excerpt:

i. The final 2019 Rule needs to clarify language regarding the discharge of BATW to FGD absorber.

In § 423.13(g)(1)[5], the proposed regulatory language states “When the bottom ash transport water is used in the FGD scrubber, the quantity of pollutants in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in Table 1 to paragraph (e)(1)[6] of this section." As written, this language can be interpreted incorrectly. It could be read in a way that requires treatment of BATW to meet the 2019 proposed FGD WW discharge standards, prior to use in the FGD scrubber. We believe that the intent of EPA was to require any BATW used as scrubber makeup to then be treated as FGD WW, meet the proposed FGD WW limits, and be discharged via NPDES permit. EPA should clarify this language either by more descript language in § 423.13(g)(1) or within the definition of FGD Wastewater or Wet FGD System.

[5] Fed. Reg. Vol 84, p. 64677
[6] (e)(1) Table 1 is the new FGD WW limits.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 7

Comment Excerpt:

- Documentation of justification for BATW purge. The Proposed Rule does not contain clear regulatory requirements on how justification for BATW purge may be documented, or how stations may determine they are in compliance prior to submitting a Discharge Monitoring Report (DMR). As drafted, it is not clear how facilities would need to document or report BATW purge justifications or how facilities may determine compliance status. Because water chemistry, maintenance requirements, and storm events vary from month to month, requiring facilities to provide materials documenting compliance with the BATW purge requirements on a monthly basis would create an ongoing, unduly burdensome obligation. The Group requests that EPA clarify that companies should retain materials showing compliance and be able to provide them on request, but that there is not a requirement to provide those materials on a monthly basis.

Commenter Name: Mike Krumland
Commenter Affiliation: Nebraska Public Power District (NPPD)
Document Control Number: EPA-HQ-OW-2009-0819-8308-A1
Comment Excerpt Number: 5

Comment Excerpt:

NPPD believes the signature and certification requirements proposed in § 423.19 are unnecessary. The requirement for a professional engineer to certify discharge of BA transport water doesn't add any value when the signatory requirements are already well established in §122.22.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 35

Comment Excerpt:

V. EPA Should Allow BATW Reuse in Any Part of the FGD System.

In the 2015 rule, EPA exempted BATW when it is introduced into the FGD scrubber. See 40 C.F.R. § 423.13(k)(1)(i). EPA's current proposal retains that exemption. UWAG recommends that EPA amend the exemption to allow the addition of BATW to any portion of the FGD system, so long as the resulting wastewater is treated to the BAT FGD limits. If facilities were able to add BATW to the FGD system at a point beyond the FGD scrubber vessel itself, the introduction of BATW would not interfere with chemical reactions within the scrubber.

According to industry experience, soluble aluminum within BATW can cause issues inside the scrubber. Aluminum-fluoride complexes can form and "blind" limestone, reducing its dissolution in water and ultimately reducing limestone utilization in the scrubber for sulfur dioxide removal and gypsum formation.

It is also possible that introducing BATW into the FGD scrubber will affect the quality of the gypsum produced, which is sometimes sold for use in wallboard manufacturing or as agricultural soil amendments with stringent gypsum quality requirements.

Because of the potential for aluminum blinding, the necessity to maintain required emission removals of sulfur dioxide, and the potential for impacts to gypsum quality, it would be preferable to add BATW to the FGD system at some point after the scrubber vessel.[35]

[35] Also, industry research shows that increased manganese in the FGD liquor can become oxidized and form precipitate layers on the FGD scrubber walls, leading to corrosion issues.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 37

Comment Excerpt:

E. EPA Should Allow BATW Reuse in Any Part of the FGD System.

Southern Company urges EPA to encourage reuse of BATW in any part of the FGD scrubber system. The 2015 ELG rule allows BATW to be introduced into the "FGD scrubber" (which Southern Company currently interprets to mean only the scrubber vessel itself) as long as the resulting FGD wastewater discharged meets the BAT FGD wastewater limits.[77] The exemption should be clarified to allow BATW to be introduced to any portion of the FGD *system* under the same conditions because the introduction of BATW into the scrubber vessel may potentially interfere with scrubber chemistry.

According to EPRI, aluminum, color, and solids within BATW can potentially interfere with FGD operations or gypsum quality.[78] Aluminum and aluminum fluoride are a concern because aluminum-fluoride complexes can "blind" limestone, reducing its dissolution in water and ultimately impacting sulfur dioxide removal and gypsum formation.[79] Color and solids could potentially reduce the marketability of gypsum byproducts (e.g., used in wallboard manufacturing) either due to accumulation of small inert particles that affect aesthetics (color) or by reducing the dewatering efficiency (increasing moisture in gypsum cake).[80] Because of these potential issues, it would be preferable to add BATW to the FGD *system* at some point after the scrubber vessel.

77 40 C.F.R § 423.13(k)(1)(i).
78 ELEC. POWER RESEARCH INST., WATER MANAGEMENT – EVALUATION OF TREATMENT FOR CLOSED-LOOP BOTTOM ASH PURGES TO FGD 3002010499 1-1 (2017) (Docket ID No. EPAHQ-OW-2009-0819-7368).
79 Id. at 1-2.
80 Id. at 1-5.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 7

Comment Excerpt:

<u>EPA Should Clarify the limits for Bottom Ash Transport Water used in the FGD Scrubber</u>

Proposed section 423.13(k)(1)(i) requires BA transport water used in the FGD scrubber to meet the BAT limits for FGD wastewater.[11] Duke Energy request that EPA clarify this requirement by explaining that BA transport water does not have to meet these limits prior to commingling with water in the FGD scrubber for units subjected to the FGD wastewater BAT limits in proposed section 423.13(g)(1)(i). Under the standard approach to technology based effluent limits (TBELs), as set out in the NPDES Permit Writers Manual, effluent limits for combined wastewater streams, as is contemplated for FGD and BA transport water, should be applied at the point of discharge.[12] Because they will be combined during or before treatment, the permit writer should combine the pollutant loadings to arrive at a single TBEL using the building block approach. Because FGD and BA transport water will be subject to the same concentration-based limits, the building block approach will result in the application of the FGD BAT limits at the point of discharge from the FGD treatment system. Any wastewater discharge from the FGD system would be subject to the BAT FGD wastewater limits, eliminating the need to place limits on BA transport water prior to the scrubber. Further, such revision would encourage reuse of BA transport water purge. Although these results are implied by application of the NPDES Permit Writers' Manual to the proposed rule, an explicit clarification in the final rule would be useful. It is also important for EPA to clarify that chemical precipitation followed by a LRTR biological treatment including ultrafiltration is not default BAT for the proposed 10% allowable BA transport water discharge to surface waters.

11 84 Fed. Reg. 64,674 (Nov. 22, 2019).
12 U.S. Envt'l Prot. Agency, NPDES Permit Writers' Manual, EPA-833-K-10-01 (September 2010), at 5-35.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 12

Comment Excerpt:

Sixth, While the 10% purge rate is improperly derived by including "estimated" precipitation and major maintenance events as I discuss in these comments, the rule does not require an operator to confirm that such events have actually occurred before availing itself of this 10% purge rate on a regular basis – i.e., 10% of the system volume every day, regardless of whether there is a 25-year precipitation event or a major maintenance event that would necessitate the emptying of the entire BATW system volume. While EPA, in passing, in the preamble, notes that this 10% volume is on an "as needed" basis, there is no further discussion of this "as needed" qualifier. Plainly, by first deriving its 10% purge allowance including one-time and infrequent events like precipitation and major maintenance, and then not requiring a showing that these events actually occur before an operator is allowed to use this allowance, is a giant loophole. In reality, the proposed rule would allow a routine (i.e., daily) BATW discharge of 10% of the "system volume" regardless of whether it rains or there is need for maintenance. And as noted above, discharging 10% of the system volume every day effectively allows the operator to discharge the entire system volume within 10 days.

38 Coordination with Other EPA Rules

Commenter Name: Jeffrey L. West
Commenter Affiliation: Xcel Energy Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8294-A1
Comment Excerpt Number: 4

Comment Excerpt:

The proposed ELG rule must align with the closure requirements for impoundments as codified in the Coal Combustion Residuals Final Rule –EPA's final Coal Combustion Residuals ("CCR") rule requires the prompt initiation of closure activities for CCR impoundments once they are no longer being used to receive CCRs or other wastewater streams. However, this rule also acknowledges the need to provide adequate time for a facility to close a CCR impoundment. The

CCR rule requires that closure activities are completed within 5 years from the last planned receipt of waste. Because large impoundments (>40-acres) may have significant quantities of free liquids that must be managed prior to closure large impoundments may be granted up to five two-year extensions. When promulgating the CCR rule EPA recognized that discharges from these ponds could occur for several years after the generating unit ceased operations.

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 10

Comment Excerpt:

Given the uncertainty of the CCR rule at this time, EPA should ensure the final compliance dates with ELG and CCR are aligned. Buckeye will provide additional comments on CCR deadlines in comments to be submitted to that rule's docket.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 3

Comment Excerpt:

CWLP appreciates the efforts made in this proposal to align the ELG rule with the Coal Combustion Residuals ("CCR") program such that additional compliance with ELG direct discharge limits will not be required prior to the requirements CWLP faces to cease wet handling of ash to its surface impoundments under the CCR rule.

Commenter Name: Josh Shapiro, Brian E. Frosh, Kwame Raoul, Dana Nessel, and Thomas J. Donovan, Jr.
Commenter Affiliation: Attorneys General of Maryland, Pennsylvania, Illinois, Michigan, and Vermont
Document Control Number: EPA-HQ-OW-2009-0819-8323-A1
Comment Excerpt Number: 3

Comment Excerpt:

Our states are submitting a single comment letter in both dockets because of the interrelated nature of the Coal Ash and ELG Proposals. See 84 Fed. Reg. at 64,626. The pollutants deposited in coal ash impoundments (the subject of the Coal Ash Proposal) are, as a general matter, byproducts of the activities subject to the ELG Proposal. To the extent that the ELG Proposal results in more waste routed to these impoundments, the demands for additional impoundment capacity will be correspondingly greater. And to the extent that unlined coal ash impoundments are permitted to continue operating, the power plants subject to the ELG Proposal will have less incentive to find other ways of complying with applicable effluent limitations.

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 3

Comment Excerpt:

The proposal will be beneficial in coordinating the implementation of other environmental regulations that dramatically impact the industry, including the Coal Combustion Residuals (CCR) Rule and the Affordable Clean Energy (ACE) Rule. These rules, among others, have created uncertainty in the industry and create challenges in planning, development, permitting, and completion of projects required for compliance with each rule.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 9

Comment Excerpt:

5. Some Units are CCR Compliant and Have Not Yet Retrofitted BATW Systems.

Units that may have repowered have not necessarily retrofitted technologies that will comply with the ELG because of the CCR rule. It is not the case, as the preamble suggests in several locations, that all coal-fired facilities are already being required to retrofit BATW recirculating systems to replace CCR ponds forced to close by the CCR rule. For example, the preamble states: "[f]lexibility for facilities to comply with BAT limitations for BA transport water beyond 2023 is not necessary because the process changes should already have occurred due to CCR rule requirements." 84 Fed. Reg. at 64,641. This is inaccurate. There are coal-fired facilities that are CCR rule-compliant without having to retrofit additional BATW technologies. For instance, some coal-fired units like Brunner Island have already installed new equipment to remove larger bottom ash solids from the BATW (dewatering bins) and to treat the BATW along with other low volume waste waters in a clarifier-based waste water treatment system prior to discharge.

These operational changes have allowed Brunner Island to eliminate use of its CCR pond (i.e., compliance with the CCR rule), but those changes do not provide for the recycling of its BATW (i.e., the future ELG requirement). Yet, the treatment of BATW prior to discharge does meet the current ELG TSS and oil and grease limits and did not require the establishment of any water quality based limits. Facilities such as Brunner Island will need time to plan, design, procure, construct, and optimize new treatment systems to comply with the Proposed Rule to recycle at least 90% of its BATW. But again, such systems at a facility like Brunner Island will only operate for a very limited time as it will be considered repowered when it phases out coal firing by the end of 2028.

39 Analytical Methods

No comment excerpts were received on this topic.

40 Economics

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois
Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 28

Comment Excerpt:

Compliance Costs and Impact on Low Income and Minority Communities

The Federal Register notice published on November 22, 2019, discusses the economic analysis conducted in support of the rule. In the Section entitled "Impacts on Residential Electricity Prices and Low-Income Minority Populations" 84 Fed. Reg. 64,643, USEPA stated that in 2015 it made an effort to evaluate what impacts the costs of the proposal would have if they all were passed on to directly to electric customers and that the current rule results in a cost of between 1 and 4 cents per month on a customer's bill. However, as USEPA is well aware, the costs of compliance will be handled differently in different States depending on the type of utility regulation applicable. Although Illinois is a deregulated State where these costs would not be passed directly to customers by the generating facilities, as an Illinois municipal utility CWLP does pass all environmental compliance costs along to our ratepayers who will pay disproportionately for all compliance costs when the remaining Illinois electric customers will not.

As a comparison to the numbers relied on in support of the rule, based on the estimated costs of installing treatment meeting the requirements of the rule for all 4 CWLP Units (at $45- 50 million dollars) CWLP examined what level of rate increase would be needed to fund the bonding of this project. If CWLP were to have to bond the approximately $50 million needed to install this treatment facility over 20 years and assuming our cmTent load and retail revenue base, it would require a rate increase of approximately 4% for our existing customers. Depending on how rate increase is implemented, it is likely CWLP would have to raise residential rates somewhat higher than 4% as under our current rate structure, commercial customers, who currently subsidize our residential rate structure, could not absorb the full 4% increase.

To better compare costs between Units that can pass down rates to customers and those that can't, USEPA also looked at economic impact of the rule based on the percentage of revenue compliance costs would represent. 84 Fed. Reg. 64,646. Facilities with compliance costs over 3% of revenue have higher incidence of impacts. USEPA concludes that the proposed rule has an impact on only two facilities of greater than 3% of revenue. Id. CWLP is not aware of whether or not it was determined to be one of these two facilities. But perfonning a similar calculation with the information available, CWLP has electric revenue from its retail and wholesale sales of approximately $240 million. If the cost of compliance is assumed at the low end of the engineering estimates available at $45 million, this cost of compliance for this rule alone would constitute 18% of our annual revenue. In addition, this discussion of cost impacts does not include the costs of compliance with the portions of the ELG rule that were not reconsidered (Dry Fly Ash conversion) and the CCR rule.

The economic assessment in the proposed rule document discusses compliance costs in relation to existing utility revenue and compares the cost to residential users to environmental benefits in its evaluation of the impact to residents. Although these assessments make sense and follow the criteria used by EPA in assessing economic impacts of other categorical user classifications, as a municipal utility discharging to another unit of local government's POTW, it is interesting that USEPA doesn't consider an analysis for the PSES more similar to those used for assessing costs on POTWs.

A strong argument can be made that additional calculations and site specific considerations should come into to play in evaluating regulatory compliance costs for essential utilities and the impact on the most susceptible parts of the population. In fact, USEPA has a history of recognizing the impacts on rate payers from the regulation of another type of utility, clean water utilities. USEPA has published several documents with evolving guidance on how to ensure household affordability and financial capability in the water industry. Examples of EPA publications in this area include: "*Interim Economic Guidance for Water Quality Standards*" (EPA 82-95-002), "*Combined Sewer Overflows - Guidance for Financial Capability Assessment and Schedule Development*" (EPA 832-B97-004), and "*Financial Capability Assessment Framework for Municipal Clean Water Act Requirements*" November 24, 2014. Given that electricity is an essential utility similar to water it would make sense for USEPA to examine the Financial Capability Assessment criteria applied to the water industry and to develop similar types of metrics for the electrical industry when developing a PSES. In the case of Springfield, as a municipally-owned electric generation facility. CWLP's rates are set based upon the costs of providing service to their constituents and does not include a profit element. CWLP serves a limited corporate area and does not have multiple generating facilities over which it can spread operating costs the way larger utilities can.

Springfield has already been shown to have a population vulnerable to the economic impacts of regulatory compliance. CWLP shares much of the same service area as SCWRD and serve a common set of rate payers. In fact, SCWRD contracts out the billing of common customers to CWLP. These rate payers are already shouldering burdens related to other clean water compliance. SCWRD has had to upgrade both of their wastewater treatment facilities to account for increases in flow and loading and compliance with nutrient removal. SCWRD and the City of Springfield are also investing in upgrading aging sewer systems and implementing improvements to deal with a combined sewer overflow. A financial assessment was undertaken for this population using some of the aforementioned USEPA documents as part of the 2011 Combined Sewer Long Term Control plan. This assessment found that the clean water needs of the area represented a burden and justified a longer-term compliance schedule. Based upon a review of information on the US Census Bureau website the City of Springfield has a medium household income below that of both the State and National average for 2019 and has a reported poverty rate of 19.6%. Given these facts it seems unlikely USEPA's assessment of impacts on low-Income rate payers adequately considers the situations such as the CWLP service area illustrating the need for a more detailed Financial Capability Assessment Framework.

Municipally owned utilities are likely to serve smaller areas constrained to their corporate limits with less ability to spread compliance costs between regions or different types of electrical generating facilities. Serving a limited area that contains economically distressed populations increases the likely hood of disproportionate impacts to low income users who are dependent upon this essential utility. Municipally owned utilities would therefore have a unique cost consideration. Establishing a new subcategory for municipally owned electrical utilities with pretreated FGD discharge to a POTW would allow USEPA to give special consideration for the level of treatment being provided by the combined pretreatment and POTW while examining the specific costs impacts of a municipal service area.

Commenter Name: Caitlin McHale
Commenter Affiliation: National Mining Association (NMA)
Document Control Number: EPA-HQ-OW-2009-0819-8327-A1
Comment Excerpt Number: 1

Comment Excerpt:

I. Coal is Critical to the U.S. Economy and Electric Power Market

This rule will certainly impact coal producers and the communities that rely on coal mining for employment and power generation. In the final rule, EPA should include a more detailed discussion of the importance of coal to the U.S. economy and electric power market.

As the preamble of the proposed rule rightly recognizes, “the rate of coal capacity retirement is affected by regulation affecting coal-fired electricity generation.”[1] Overly burdensome regulations in the last decade, like the 2015 ELG Rule, have prompted some early plant retirements and made coal-generated electricity less competitive in the market. The 2015 ELG

Rule unjustifiably imposed substantial burdens on the coal industry and the communities that rely on coal-generated electricity, forced plant closures, and caused significant job losses.

The preamble also properly acknowledges that "market conditions in the electricity generation sector have changed significantly and rapidly in the past decade"[2] resulting in "a depressive effect" on "both coal-fired and nuclear-powered generation."[3] But recent regulatory changes to PJM's capacity market structure and ongoing reforms to the Public Utility Regulatory Policies Act to restore competition in the electricity market could make coal a more attractive commodity again. EPA should recognize that the nation's electric power market is dynamic and complex. While regulatory frameworks that favored renewable energy sources over coal altered the demand for coal-generated electricity in recent years, concerns about grid reliability and other market and policy forces could change that trajectory.

Despite the unnecessary regulatory burdens imposed on the coal industry during the previous administration that caused premature plant closures, coal remains an important employer and driver of the U.S. economy.[4] From an employment perspective, the coal mining sector provides over 100,000 direct jobs and 300,000 indirect jobs to hardworking Americans in 26 states. The average annual salary for a miner is more than $80,000, well above the U.S. average wage of around $53,000. Even as some utilities supplement or replace traditional generation with alternative sources, coal remains a critical provider of electricity. 30 percent of U.S. electricity comes from coal, and 87 percent of U.S. fossil energy reserves (including coal, natural gas, and oil) comes from coal on a British Thermal Unit (BTU) basis. Coal is a reliable source of low-cost energy for millions of Americans. Therefore, EPA should include a more detailed discussion of the importance of coal to employment, the economy, and baseload power generation in the final rule.

[1] 84 Fed. Reg. 64626 (Nov. 22, 2019).
[2] Id.
[3] Id. at 64626.
[4] National Mining Association, 2019 Mining Facts, https://nma.org/wp-content/uploads/2019/03/2019-External-Fact-Book-1.pdf.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 116

Comment Excerpt:

XXIII. The Regulatory Impact Analysis on Which EPA Based its Evaluation of Regulatory Options Underestimates the Actual Costs, and Thus the Economic Impacts, of Those Options and of the ELG Rule.

The BAT provisions of the Clean Water Act require that BAT technologies be economically achievable for the industry category or class and authorizes EPA to reject technologies that the Agency concludes are not. See CWA § 301(b)(2)(A), 33 U.S.C. § 1311(b)(2)(A). EPA may use its expert discretion to decide what level of economic impact is, or is not, economically achievable by the category or subcategory to which the ELGs apply. *See e.g., Waterkeeper All., Inc. v. EPA*, 399 F.3d 486, 518 (2d Cir. 2005) ("[E]conomic achievability is a determination the EPA must make on an industry-by-industry basis because each industry has its own special attributes and requires an individual assessment of appropriate financial criteria"); *Nat'l Wildlife Fed'n v. EPA*, 286 F.3d 554, 563 (D.C. Cir. 2002); *see also Riverkeeper, Inc. v. EPA,* 358 F.3d 174, 195 (2d Cir. 2004). One important factor is the financial stress affected facilities face from other environmental regulations, as EPA has recognized in developing ELGs for other industries. See, e.g., EPA, *National Emission Standards for Hazardous Air Pollutants for Source Category: Pulp and Paper Production; Effluent Limitations Guidelines, Pretreatment Standards, and New Source Performance Standards: Pulp, Paper, and Paperboard Category,* 63 Fed. Reg. 18,504, 18,550 (Apr. 15, 1998).

For the reasons discussed below, EPA should determine that ELGs consistent with UWAG recommendations are economically achievable, while ELGs that add substantial costs for additional BATW handling for repowered facilities and for low utilization unit are not.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 118

Comment Excerpt:

B. EPA's Analysis of Economic Impacts Should Account for the Costs of Other ELG Requirements Imposed on the Same Facilities.

EPA's analysis of the economic impacts and environmental benefits[241] of the rule uses the 2015 ELG Rule as the "baseline" and evaluates the extent to which the options it considered will increase or decrease costs and economic impacts relative to that baseline. EPA, *Regulatory Impact Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* EPA-821-R-19-012, EPA-HQOW-2009-0819-8237 (Nov. 1, 2019) ("2019 RIA"). Although that approach is consistent with OMB protocols for economic impact assessment of proposed rules, in this situation, it captures only a part of the effluent limitations guidelines' economic impact.

The provisions in question do not operate independently from the rest of the 2015 ELG rule, which includes new and expensive technology-based requirements for fly ash transport water, among other requirements. Some facilities in the industry category will need to bear the costs of retrofitting technologies for fly ash transport water, as well as BATW and FGD wastewater. Understanding the economic impact of the entire ELG rule requires consideration of the economic impacts of all applicable ELG provisions.

That EPA's Proposal arises due to the Agency's reconsideration of two requirements of the 2015 ELG Rule makes it no less important for EPA to analyze the *total* impacts of the ELG rule. EPA's decisions about affordability should be based on the *total* investment the ELG rules (and other environmental rules) will require. As a relatable example, consider decisions a family must make about a family car. Similar to a power company that requires a certain amount of generation capacity to serve load, a family requires a certain amount of transportation capacity, and many families rely on one or more vehicles to meet those needs. When faced with expensive requirements for keeping the vehicle on the road, the family considers the totality of operational costs in the context of transportation needs and replacement costs. When determining whether to fix a car that requires new brakes, tires, and emissions equipment, the family considers the entirety of the cost burden, not each cost separately. Operating a generation fleet is similar: all costs are considered in investment and retirement decisions. As with this example, a clear understanding of the total costs is essential to determining what is affordable. Thus, while EPA's analysis of the economic impact of changing the 2015 rule is useful as far as it goes, it does not provide a full accounting of the economic impact of the ELG rules, of which this Proposal is just one part.

UWAG urges EPA to consider these cumulative costs in assessing the economic impacts of regulatory options. IN UWAG's view, EPA's current record supports a finding that the technologies EPA has selected, with the subcategories EPA proposes *and the revisions and modifications UWAG recommends*, reflect the most that is economically achievable.

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[241] In the limited time available for comment, UWAG was not able to perform a detailed analysis of EPA's assessment of the environmental benefits of the proposed rule, which EPA prepared pursuant to Executive Order 12866. EPA has taken the position that the presence or absence of environmental benefits is not relevant to the choice of best available technology or the establishment of technology based limits and that the Agency does not make decisions based on the expected benefits. See, e.g., Supplemental EA at 1-1. UWAG therefore assumes that EPA does not intend to rely on environmental benefits for purposes of setting revised BAT limits.
That said, UWAG is particularly concerned with two aspects of the benefits analysis. First, UWAG renews its request that EPA take steps to ensure that assessment of pollutant loadings does not count pollutants present in intake waters. EPA's pollutant loading assessment is driven by two factors: effluent concentrations and effluent flows. Effluent flows, in turn, are driven by the amount of water withdrawn from source waters. Influent and, thus, effluent flows at steam electric plants tend to be higher than flows in other industries because of steam electric plants' unique operating needs (although the industry continues to explore ways of reducing water withdrawals by reusing water). Thus, it is particularly important that EPA's assessment remove influent pollutants for the industry analysis to obtain accurate pollutant loading.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 119

Comment Excerpt:

C. EPA's Economic Impact Analysis Should Account Fully for Plants Induced to Retire by the ELGs and Other Impacts Potentially Underestimated By its Modeling.

To identify units likely to incur costs to comply with the Proposed Rule, EPA reviewed and revised the industry profile it developed for the 2015 rule. 2019 RIA, Executive Summary at ES-1, Section 2; ERG 2019 Industry Change Memo.

EPA removed from the profile 78 plants (comprising 160 units) that announced by October 2018 that they would retire on or before December 31, 2028. ERG, 2019 Industry Change Memo at 3, *citing* ERG, EPA-HQ-OW-2009-0819-7374; id. at 15-17. These are plants that were included in EPA's 2015 industry profile and, thus, had not previously announced that they would retire on or before December 31, 2023 (the outside deadline imposed by the 2015 rule). In addition, ERG identified another 39 units at 21 plants that announced plans to retire after the October 2018 cut-off. Those changes are not reflected in the profile analyzed. ERG, 2019 Industry Change Memo at 9-10.[242] Thus, according to the ERG Industry Change Memo, in the four short years since EPA issued the 2015 rule, 99 coal-fired power plants, comprising 199 units. This total is considerably higher than the 78 baseline closures EPA's Integrated Planning Model ("IPM") predicts.[243]

ERG's analysis of the rationale offered for announced retirements indicates that only about 16 of the units in question retired solely due to age or lack of demand. ERG, 2019 Industry Change Memo at 11-12. The remaining units retired due to economic or regulatory imperatives that the ELGs could have influenced. This long list of ELG-influenced retirements stands in stark contrast to the one ELG-induced plant retirement (two units, or 843 MW) that EPA's IPM model predicted would retire solely as a result of the 2015 rule. EPA, *Regulatory Impact Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* EPA-821-R-15-004, EPA–HQ-OW-2009-0819-5849 (Nov. 2015) ("2015 RIA"), Section 5 at 5-10; 80 Fed. Reg. at 67,867.

Even if one assumes that the 2015 rule was a major factor in causing the premature retirement of only the 28 power plants the ERG 2019 Industry Change Memo lists as retiring due to environmental regulations, the discrepancy strongly indicates that EPA's impact assessment tools were not very accurate predictors of the economic consequences of the final rule. Whether the correct number of ELG-induced or influenced plant closures is closer to 99 (199 units) or 28, the facts indicate that the economic impact of the 2015 rule was, and continues to be, substantial. At the high end, the ELG-influenced closures amount to a little over 27 percent of 735 coal-fired units EPA identified as affected by the 2015 Rule and over 28 percent of the 347 plants EPA identified as potentially affected. It is far higher than the 0.3 percent of the industry EPA projected would be retired as a result of the 2015 rule. 80 Fed. Reg. at 67,867. In assessing the potential economic impacts of the Proposed Rule, EPA must consider and account for these real world impacts in assessing what level of treatment is economically achievable.

One reason for the substantial discrepancy between EPA's modeled projection and the real-world consequences may be the cost estimates EPA used when modeling economic impacts using the IPM. Those costs were then, and continue to be, far too low. Using more realistic cost values, such as those developed by EPRI, would provide a more accurate appraisal of the proposal's economic impacts. But there are other issues raised by EPA's regulatory impact modeling that also deserve consideration.

Another reason for underestimating the impacts of the 2015 rule likely is EPA's assumption that costs imposed by virtue of CCR rule requirements that prohibit the use of existing waste treatment facilities are costs of the CCR rule, rather than costs of the ELG rule. That is not the case. When a CCR rule requires the closure of an existing surface impoundment, the cost of the CCR rule is the cost of prematurely closing that impoundment. But the CCR rule does not in and of itself impose costs for treating the wastewater that can no longer be treated in the impoundment. The requirement to treat wastewater at all (or any preclusion against its discharge) is imposed by virtue of the CWA, and it is the CWA that determines the nature and cost of the technology that must be applied.

In addition, using the IPM to assess potential impacts on reliability and costs to wholesale and retail customers may underestimate real-world impacts because of the assumptions inherent in the model.[244] The IPM was developed primarily to aid power companies in making economically efficient generation choices.[245] The model relies on a variety of inputs, such as fuel prices, technology costs, energy prices, demand (which is assumed to be inelastic), and timing. Depending on the selections made (maximum, average or median, low end) and the window of time afforded, alternatives may look more or less economically viable.[246] Equally important, the alternatives assessed by the model assume that the alternatives evaluated can be feasibly put in place within the time frame chosen (unless that time frame allowed by the rule is so short as to fall outside the minimum window of time specified in the model).[247] In other words, it does not account for physical or regulatory impediments that often arise in connection with actual projects. So, for example, where new gas, solar, or wind capacity is projected to be the most economical alternative to a coal-fired capacity, the model assumes that new capacity can be brought online in the time frame specified (Shavel, Celebi, and Chupka (2014)). IPM does not account for the often significant delays that projects can encounter in obtaining regulatory or other approvals for the project as a whole or essential components of the project, such as new gas pipelines or new transmission lines (Shavel, Celebi, and Chupka (2014)). [248]

The most dramatic shortcoming of IPM for forecasting closures is that it is based on a specification of inelastic demand. This means that the quantity of electricity that is demanded is specified externally to the model and does not change with electricity prices.[249,250,251] In fact, over the time frames typically modeled in IPM, estimated elasticities range from -0.3 to -1.1 compared to the IPM inelastic specification of 0. The implication is that, whereas IPM assumes that a 1 percent change in electricity price has no effect on electricity consumption, the reality is that a 1 percent change in price leads to a 0.3 percent to 1.1 percent reduction in electricity consumption.

EPA states that, because cost changes are expected to be relatively small, the inelastic demand specification is appropriate. Clearly, if costs are underestimated, this point is weakened. More importantly, this viewpoint is conceptually incorrect. In markets with a small number of participants, small price changes may not affect market quantities. However, the situation that EPA is analyzing affects hundreds of millions of business, households, and manufacturing facilities. These entities will be making billions of electricity use decisions—at such a large scale, the assumption that cost changes won't affect consumption decisions is not valid.

This lack of sensitivity to the demand side in electricity results in a lack of sensitivity in detecting closures. This is borne out in a comparison of the baseline closure that EPA calculated in 2015 and 2019 for the ELG rule. As noted by EPA, "[t]he 2015 rule analyses incorporated compliance costs associated with the 2015 CPP, resulting in, among other things, baseline retirements associated with that rule in the Integrated Planning Model (IPM)." 2019 RIA at 2-8. Here, the CPP is the Clean Power Plan, a significant rule that would be expected to lead to some closures. Indeed, the 2015 ELG Regulatory Impact Analysis prepared for the ELGs predicts 79 baseline closures by 2030. However, the 2019 ELG Regulatory Impact Analysis, which does not include CPP in the baseline, predicts 78 baseline closures. The apparent implication is that removing the CPP from the regulatory baseline had virtually no effect on baseline retirements.

As noted by other reviewers of IPM, documentation for IPM is limited. Without this documentation, the results of the modeling cannot be verified to show that the "methodology or implementation of the model is correct or in line with accepted economic principles." Power, Power, and Brown 2015 at 8. Although, without examining model runs, it is not possible to make this judgement conclusively, one plausible reason for this lack of change in retirements is the inelastic demand specification inherent in IPM.

Thus, using more accurate and complete costs and re-running IPM still may not provide an accurate picture of the economic impacts of these expensive new regulations for the facilities that must absorb those costs. EPA can and should use all of the information at its disposal to judge what is economically achievable.

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[242] UWAG is aware of some additional retirements not included in ERG's 2019 Industry Change Memo which may affect EPA's analysis. See EPRI 2020 Comments, Appendices A, B, F at A-1, B-1, F1 (adjusting cost analysis to account for retirements since the end of 2018).

[243] EPA's Supplemental TDD acknowledges that the population of coal-fired generating units and plants decreased to 550 generating units at 284 plants, amounting to 25 percent fewer generating units than the 2015 rule population. Supplemental TDD at 3-4.

[244] Shavel, I., M. Celebi, and M. Chupka ("Shavel, Celebi, and Chupka (2014)"), *Comments on EPA's Modeling of the Impacts of the Proposed Clean Power Plan in Arizona,* prepared for Salt River Project, THE BRATTLE GROUP, INC., Washington, DC. (Nov. 21, 2014), https://www.ferc.gov/CalendarFiles/20150220105944-Brattle%20Whitepaper.pdf.

[245] Direct Testimony of Judah L. Rose on Behalf of Duke Energy Ohio, Inc., *In re: Application of Duke Energy Ohio, Inc., for Approval to Modify Rider PSR,* Nos. 17-872, 17-873, 17-874 (Pub. Utils. Comm'n Mar. 31, 2017) https://www.eenews.net/assets/2018/05/24/document_pm_01.pdf.

[246] Jonathan A Lesser, Missing Benefits, *Hidden Costs: The Cloudy Numbers in the EPA's Proposed Clean Power Plan* (June 2016), https://media4.manhattaninstitute.org/sites/default/files/R-JL-0616.pdf (last visited Jan. 7, 2020).

[247] Peter Behr and Hannah Northey, *Computer Models Contest EPA Clean Power Plan's Reliability Impacts,* ENERGYWIRE.COM (Dec. 17, 2014), https://www.eenews.net/stories/1060010675/print (last visited Jan. 16, 2020); Shavel, Celebi, and Chupka 2014.

[248] See, e.g., Benjamin Storrow, *Interior Delays Finding on Large Offshore Wind Project* (Aug. 9, 2019), E & E NEWS PM, https://www.eenews.net/stories/1060898805 (last visited Jan. 14, 2020) ("Vineyard Wind has long been viewed as a bellwether for the offshore wind industry…. But it has encountered mounting challenges in recent months after NOAA Fisheries raised questions about the environmental impact statement conducted by the Bureau of Ocean Energy Management…."); see also Section XV.B.2, n. 174.

[249] W.S. Jaglom, J.R. McFarland, M.F. Colley, C.B. Mack, B. Venkatesh, R.L. Miller, J. Haydel, P.A. Schultz, B. Perkins, J. Casola, J.A. Martinich, P. Cross, M.J. Kolian, and S. Kayin, *Assessment of Projected Temperature Impacts from Climate Change on the U.S. Electric Power Sector Using the Integrated Planning Model,* ENERGY POLICY 73:524–539 (2014).
[250] J. McFarland, Y. Zhou, L. Clarke, P. Sullivan, J. Colman, W.S. Jaglom, M. Colley, P. Patel, J. Eom, S.H. Kim, G.P. Kyle, P. Schultz, B. Venkatesh, J. Haydel, C. Mack, and J. Creason, *Impacts of Rising Air Temperatures and Emissions Mitigation on Electricity Demand and Supply in the United States: A Multi-Model Comparison,* CLIMATIC CHANGE 131(1):111–125 (2015).
[251] T.M. Power, D.S. Power, and J.M. Brown, *Misuse of Integrated Planning Model as an Assessment Tool in the Tongue River Railroad DEIS,* prepared for the Northern Plains Resource Council, Missoula, MT: POWER CONSULTING, INC. (Sept. 22, 2015).

Commenter Name: Colton Fagundes
Commenter Affiliation: American Sustainable Business Council
Document Control Number: EPA-HQ-OW-2009-0819-8463-A1
Comment Excerpt Number: 3

Comment Excerpt:

Despite claims from the industry, most power plants will incur zero costs to comply with the 2015 ELG rule. In fact, in 2015 the EPA estimated that overall only about 12 percent of all power plants and 28 percent of coal or petroleum burning plants will incur any costs. For all but a handful of plants, those costs will amount to less than 1 percent of the company's revenue. This small expense will have a profound impact on our nation's environmental wellness and create a more sustainable business model. The argument that these corporations cannot comply to these regulations due to a cost hindrance is simply untrue.

The decision to roll back Effluent Limitations Guidelines is a decision that is not just bad for the environment, but bad for business. The American Sustainable Business Council is asking the EPA to reconsider the rollback and consider the other stakeholders affected by this decision. The short-term fiscal health of a few, large corporations cannot come at the expense of our environment, our nation's communities, and our nation's businesses.

Commenter Name: Thomas Weissinger
Commenter Affiliation: Talen Energy
Document Control Number: EPA-HQ-OW-2009-0819-8470-A2
Comment Excerpt Number: 8

Comment Excerpt:

4. Including Repowered Units in the Retirement Subcategory Is Consistent with EPA's Economic Impact Analysis

EPA's Economic Impact Analysis—one of the lynchpins of its Regulatory Impact Analysis—included no estimate of the costs or economic impacts of requiring units that would repower by December 31, 2028, to install BATW or FGD wastewater treatment technology that they would use for only three to five years. Instead, EPA removed those facilities from the industry profile for purposes of assessing the costs and economic impacts of the rule. See ERG 2019 Industry Change Memo at 5; Supplemental TDD at 3-4. Specifically, the Eastern Research Group (ERG), EPA's contractor, listed Brunner Island as being repowered by 2028 in their analysis and did not include any costs for these units to comply with either the BATW or FGD wastewater ELG requirements.

As UWAG's comments (Talen is a UWAG member) on the economic impacts of the rule will demonstrate, requiring repowered facilities to incur the substantial costs of retrofitting technologies that will be used for far less than the standard 20-year depreciation period EPA used to assess annualized economic impacts makes the economic impact of the rule much greater, in real terms, for repowering facilities. If EPA elects not to include repowered facilities in the retirement subcategory, it must account for and explain why they are justifiable.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 180

Comment Excerpt:

D. Integrated Planning Models Show That No Regulatory Option Would Have Meaningful Impacts on Coal Capacity, Coal Retirements, Reliability, or Electricity Prices, While a Zero-Discharge Rule Would Maximize Environmental Benefits.

Throughout the rulemaking record, EPA suggests that its decision-making process was guided by concerns over preventing coal plant retirements and protecting grid reliability.[665] As discussed elsewhere in this comment letter, not only are these invalid bases for deriving BAT limitations, but EPA has also failed to present sufficient record support to establish that the concerns are anything more than speculation.[666] On the contrary, the record shows that the impacts of the steam electric ELGs on coal capacity, grid reliability and electricity prices will be vanishingly small, even under regulatory options more aggressive than EPA is currently proposing.

The Integrated Planning Model ("IPM") results in the record show minimal impacts, even for the most stringent regulatory option considered by EPA (Option 4). Under EPA's baseline scenario, coal capacity will decline by 18% between 2021 and 2050.[667] Under Option 4, the result is exactly the same – coal capacity will decline by 18% between 2021 and 2050.[668] Under EPA's baseline, electricity prices will increase by 36%.[669] Under Option 4, the result is exactly the same.[670] In short, Option 4 would have virtually <u>no impact</u> on coal capacity and electricity prices.[671]

The relative impacts of the various options compared to each other are even smaller. Coal capacity in 2050 under Options 2 and 4 would be 145.3 and 145.4 GW, respectively, a difference of 0.07%.[672] Electricity prices in 2050 under Options 2 or 4 would be exactly the same – 0.02% higher than baseline prices.[673] Again, there would be no impacts at all to coal capacity or electricity prices if EPA chose to adopt a more stringent regulatory option. For reasons discussed elsewhere, these results are fatal to EPA's speculative concerns about grid reliability, which depend on concerns about the impact of the Steam Electric ELGs on coal capacity.[674]

The same could be said of an even more stringent regulatory option that would require complete elimination of discharges of bottom ash transport water and FGD wastewater. NRDC – in collaboration with other commenters – contracted ICF to analyze an alternative ELG approach using their IPM model with assumptions specified by commenters. Commenters specifically developed assumptions for a more stringent, zero-discharge ELG option, described here as "Option 5," which was compared against NRDC's Base Case. NRDC's Base Case forecast differs from EPA's baseline in the 2019 proposal. Generally, NRDC's Base Case has less coal capacity, fewer carbon emissions, and lower total system costs than EPA's baseline between 2021 and 2046. This is likely driven, in part, by the use of more recent government projections for technology and fuel costs in NRDC's Base Case. EPA's baseline reflects electricity demand assumptions and fuel supply curves from U.S. Energy Information Administration's Annual Energy Outlook 2018 (AEO2018). NRDC's Base Case uses the most recent outlook, AEO2019, for both electric demand projects and fuel supply curves. These assumptions have a significant impact on the economics of coal plants under "business-as-usual" policy, with AEO2019 projecting much lower near- and mid-term gas prices than AEO2018: AEO2019's gas prices in 2020 are 19 percent lower and in 2030, 14 percent lower, than the forecasts in AEO2018. In addition, NRDC's base case includes more up-to-date state policies, reflecting recent revisions to state Renewable Portfolio Standards, technology carve-outs (e.g. offshore wind and battery storage targets), and Clean Energy Standards as of June 2019, with assumptions specified by NRDC primarily based on EIA and NREL.

"Option 5" zero-discharge compliance costs were obtained from the current rulemaking record.[675] For the units without zero-discharge compliance cost estimates in the above-cited document (including 5 units for bottom ash transport water and 3 units for FGD wastewater), commenters independently estimated compliance costs.[676] NRDC's IPM inputs, assumptions, and outputs are provided in detail in attachments to these comments.[677]

While Option 5 is based on a different base case than EPA's Option 2 and 4, we can compare the incremental impact of these options. Considering the incremental impact, or the effect that each option has on capacity, emissions, generation, and costs compared to their respective baselines, allows us to compare the options – and the impact of each option on the electricity system – even with slightly different baselines.

NRDC found the following. Compared to the NRDC base case, a zero-discharge Option 5 would result in a small additional reduction of coal capacity of 0.2 GW, or 0.1% of total coal capacity, by 2040. Coal generation would decline by an additional 1,130 GWh by 2040, a modest reduction with no impact on reliability or resiliency in the IPM model. Compliance costs would also be modest. Annual, nationwide incremental system cost under Option 5 in 2030 would be

$57 million (2016$), falling to $48 million in 2040, as shown in the table below. This is less than EPA assumed for Option 4 ($68 million in incremental costs in 2040).[678] Fuel prices –for both gas and coal – are not substantially impacted by Option 5.

Option 5 Changes Relative to NRDC Base Case					
PRICES	2020	2025	2030	2035	2040
Total Costs (billion $)	0.044	0.059	0.057	0.057	0.048
National Wholesale Electricity Price (mills/kWh)	-0.01	-0.01	0.02	-0.01	0.00
Natural Gas Prices (2016 $/MMBtu)					
Henry Hub	0.00	0.00	0.00	0.00	0.00
Delivered	0.00	0.00	0.00	0.00	0.00
National Delivered Coal Prices (2016 $/MMBtu)	0.00	0.00	0.00	0.00	0.00

On the other hand, Option 5 would generate substantial environmental benefits relative to EPA's Options 2 and 4. Compared to EPA's baseline, Option 2 (EPA's preferred option) would lead to higher emissions of all modeled pollutants in all years between 2021 and 2046. Over the next 25 years, this option would result in a cumulative increase of 69 million metric tons of CO2, 93,000 tons of SO2, and 77,000 tons of NOx emissions from the power sector.

Option 2 Changes Relative to EPA baseline								
NATIONWIDE EMISSIONS	2021	2023	2025	2030	2035	2040	2045	Cumulative (2021 - 2046)
SO_2 (million tons)	0.004	0.005	0.005	0.006	0.002	0.002	0.003	0.093
NO_x (million tons)	0.003	0.005	0.005	0.004	0.003	0.001	0.002	0.077
CO_2 (million metric tons)	1.35	2.77	2.38	3.95	2.43	2.05	2.67	69.22

Even EPA's more stringent option, Option 4, finds cumulative pollution increases compared to baseline. Over the next 25 years, this option would result in a cumulative increase of 12 million metric tons of CO2, 69,000 tons of SO2, and 33,000 tons of NOx emissions from the power sector.

Option 4 Changes Relative to EPA Base Case								
NATIONWIDE EMISSIONS	2021	2023	2025	2030	2035	2040	2045	Cumulative (2021 - 2046)
SO_2 (million tons)	0.005	0.005	0.002	0.002	0.001	0.004	0.003	0.069
NO_x (million tons)	0.003	0.004	0.003	0.001	0.000	0.000	0.002	0.033
CO_2 (million metric tons)	0.77	2.18	0.30	1.18	-0.69	-0.35	1.35	12.46

However, NRDC's modeling of Option 5 finds that a more stringent standard than Option 2 or Option 4 could result in measurable emissions reductions at modest compliance cost and with minimal impact on the energy system or energy prices. Compared to NRDC's more updated Base Case, Option 5 cuts cumulative climate- and health-harming pollution over the next 25 years (2021 – 2046), with a reduction of 7.3 million metric tons of CO2, 25,000 tons of SO2, and 37,000 tons of NOx emissions from the power sector.

Option 5 Changes Relative to NRDC Base Case						
NATIONWIDE EMISSIONS	2020	2025	2030	2035	2040	Cumulative (2021 - 2046)
SO_2 (million tons)	0.002	0.000	0.000	-0.001	-0.003	-0.025
NO_x (million tons)	-0.001	-0.001	-0.002	-0.001	-0.002	-0.037
CO_2 (million metric tons)	0.46	0.26	-0.42	-0.17	-0.82	-7.31

These reductions come from a small, additional reduction in coal capacity of 200 MW by 2030 and an associated reduction in coal generation of 479 gigawatt-hours ("GWhs") in 2030 and 1,130 GWhs in 2040. These small reductions in coal capacity and generation related to Option 5 should have no impact on grid reliability or resiliency and do not substantially impact energy or fuel prices. In fact, wholesale electricity prices, Henry Hub gas prices, and delivered gas and coal prices are lower on average under Option 5 than NRDC's Base Case between 2021 and 2046.

In short, if EPA were to eliminate the discharge of bottom ash transport water and FGD wastewater – as required by the CWA – it would create no meaningful impacts on coal capacity, grid reliability, or electricity prices, but it would generate substantial environmental improvements over all of the regulatory options that EPA has considered to date.

[665] See, e.g., 84 Fed. Reg. at 64,639 ("Low utilization boilers tend to operate only during peak loading. Thus, their continued operation is useful, if not necessary, for ensuring electricity reliability in the near term"); id. at 64,638-39 (discussing the need for subcategories to prevent "competitive disadvantage" and "disparate costs"); id. at 64,640 (speculating about "significant reliability problems," and stating that "orderly retirement of older facilities [is] vital to ensuring electricity reliability").
[666] See, e.g., Section X – Subcategories Unjustified.
[667] Proposed RIA at 5-6, Tbl. 5-2.
[668] Id. at 5-7, Tbl. 5-3.
[669] Id. at 5-6, Tbl. 5-2.
[670] Id. at 5-7, Tbl. 5-3.
[671] Id. at 5-6 to 5-7, Tbls. 5-2 & 5-3. The differences in coal capacity and electricity prices between baseline and Option 4 for any given year are vanishingly small (less than 1%).
[672] Id.
[673] Id.
[674] See Section X.E – Reliability.
[675] ERG, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090, Docket ID No. EPA-HQ-OW-2009-0819-8220 (Sept. 25, 2019). For bottom ash transport water, zero-discharge compliance costs were obtained from EPA's "baseline" option. For FGD wastewater, zero-discharge compliance costs were obtained from EPA's Option 4.
[676] Bottom ash capital costs were estimated by regressing capital cost against nameplate capacity for all units that EPA assumes will have to convert from 'wet sluicing with discharge' to ZLD. Annual O&M and recurring costs for bottom ash appear to be independent of both capacity and generation, so we assumed that average O&M and recurring costs for all units converting from wet sluicing with discharge to ZLD would apply to the five units for which we derived cost estimates. For the three units for which we derived FGD compliance costs, we calculated capacity and O&M costs using the membrane filtration cost curves in the record, assuming pretreatment + membrane with onsite storage and disposal. ERG, Flue Gas Desulfurization Membrane Filtration Cost Methodology – DCN SE07096, Docket ID No. EPA-HQ-OW-2009-0819-7811 (Aug. 23, 2019). We did not have enough information to calculate recurring costs for these three units, so we assumed zero.
[677] NRDC, "NRDC Assumptions – ELG Runs" spreadsheet (attached); NRDC, "ELG Run IPM Outputs" spreadsheet (attached).
[678] Proposed RIA at 5-7.

Commenter Name: Colton Fagundes
Commenter Affiliation: American Sustainable Business Council
Document Control Number: EPA-HQ-OW-2009-0819-8463-A1
Comment Excerpt Number: 2

Comment Excerpt:

Recreational fishers generate over $40 billion a year in economic activity. All outdoor watersports, including fishing, kayaking, rafting, canoeing, scuba diving and other watersports collectively generate nearly $175 billion year. By letting this proposal go through, the EPA is telling the multitudes of businesses across those sectors that their hard work and job creating enterprises are not valued.

Clean waterways are also vital for sectors like breweries, the seafood industry and the hospitality industry. For example, the craft brewing industry contributed $76.2 billion to the U.S. economy in 2017, more than 500,000 jobs, and depends heavily on clean water to create a high-quality product for its consumers. For the seafood industry, many businesses are especially concerned with mercury pollution originating from coal-fired power plant effluent. Waterside restaurants and lodging lose business if their lake or river is unfit for swimming or recreation. A clean water source allows each of these industries to provide safe products and activities for their customers to enjoy, while also reducing the cost of water treatment for each sector.

41 Benefits

Commenter Name: Anonymous
Commenter Affiliation:
Document Control Number: EPA-HQ-OW-2009-0819-8285-A1
Comment Excerpt Number: 1

Comment Excerpt:

Given the opportunity to comment on Environmental Protection Agency's proposed rule entitled Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, I would like to voice my concern for the oversight of the EPA on the valuation of ecosystem services. Throughout the report, the EPA references social costs, but does not explicitly acknowledge the costs on ecosystems. Such costs are notably difficult to monetize; however, they should be considered a relevant concern in the implementation of this proposed rule. Inclusion of the impacts of wastewater pollution from steam electric power on the ecosystem should be assessed in greater depth. The concerns for ecosystemic consequences should be addressed with more weight considering this act is being proposed by the Environmental Protection Agency.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 10

Comment Excerpt:

EPA's approach also does not reflect the uncertainties in the scientific understanding of disinfection byproduct formation, exposure, and toxicity.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 53

Comment Excerpt:

7.1.4 **EPA's downstream transport model does not provide an accurate assessment of site-specific downstream PWS inlet concentrations and needs to be sufficiently validated.**

EPA's use of the D-FATE model [EPA, 2019b] to estimate downstream bromide concentrations relies on broad assumptions (e.g., discharge mixing, identification of receiving waterbodies, timeframe of input data, etc.) that result in estimates that may be useful for evaluations on a national scale but are not of high enough resolution for assessment of transport from specific power plant facilities to specific downstream PWS. EPRI noted several examples of model inputs that would benefit from a more detailed approach:

- EPA assumed complete vertical and horizontal mixing of the discharge with the receiving waterbody. The error introduced by this assumption becomes more pronounced at smaller spatial scales.
- Long stream distances were modeled between discharges and PWS inlets (40 miles on average; EPA, 2019b).
- Meteorology data used in the Enhanced Runoff Method (EROM) [EPA, 2019b] are from 1971-2000. EROM estimates for the continental United States are less accurate outside of this period. Extrapolation to present-day and future years may not be appropriate, given changing precipitation patterns [Georgakakos et al., 2014; Melillo et al., 2014; Drum et al., 2017].
- Flows were developed on a Vector Processing Unit (VPU) basis [approximately equivalent to a U.S. Geological Survey (USGS) second-level hydrologic region code (HUC2)], for use in the National Hydrography Dataset Plus (NHDPlusV2) geospatial surface water framework. A VPU-scale assessment is reasonable where uncertainty in flow is distributed equally across the area of evaluation. Use of these flow estimates on a smaller scale (for example, on a HUC4 or smaller watershed) may lead to biased flow

estimates if the relevant characteristics of the sub-area of interest differ from the average value observed across the VPU.

The use of the detection limit or reporting limit value as a surrogate for nondetect measurements is another confounding factor and provides a conservatively high estimate of observed downstream concentrations. This approach is not consistent with EPA's procedures in other areas of the bromide evaluation (e.g., ERG, 2019b).

As stated by EPA [EPA 2019d], modeled bromide downstream concentrations were generally one third or less than measured bromide at PWS. Lower modeled concentrations are expected since the model does not account for all sources of bromide within a watershed. EPA also appropriately acknowledged the potential impact of uncertainty associated with various assumptions such as those mentioned above in accounting for differences between measured and modeled values. The use of these generalized assumptions results in greater uncertainty when applied to individual watersheds or at the PWS level. A more robust, site-specific validation of the transport model that addresses major sources of uncertainty would strengthen EPA's modeling approach.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 54

Comment Excerpt:

7.2 **EPA's approach does not reflect the uncertainties in the scientific understanding of disinfection byproduct formation, exposure, and toxicity.**

7.2.1 **EPA oversimplifies bromide-TTHM formation and TTHM-bladder cancer relationships.**

EPA used a statistical relationship between bromide entering a PWS treatment facility and excess cancer risk developed by Regli et al. [2015] to evaluate regulatory options for bromide [EPA, 2019b]. The Regli et al. [2015] methodology consists of two components: 1) an empirical relationship between bromide concentration at the PWS inlet and formation of total trihalomethanes (TTHM), derived from EPA's Soil and Water Assessment Tool (SWAT) model database, and 2) a regression analysis of TTHM exposure and excess lifetime risk of bladder cancer, derived from epidemiological studies. Regli et al. [2015] combined the results of these two evaluation steps and concluded that with a 50 µg/L increase in bromide above baseline levels, 90% of 201 drinking water plants in the SWAT model database would have seen an increase in TTHM at or above 1 µg/L, and consequently an increased cancer risk of at least 10^{-4}.

EPRI [2019] detailed several concerns about the Regli et al. [2015] methodology. Regli et al. [2015] noted a diminishing rate of increase in TTHM per µg/L increase in bromide at higher initial water bromide concentrations, possibly due to limited organic precursors available for DBP formation. Thus, there is no single relationship that can be drawn between an increase in bromide mass loading and a resulting level of TTHM formed in the wastewater. In addition, the Regli et al. [2015] methodology does not account for processes within a drinking water treatment system that increase or decrease TTHMs, such as system residence time, aeration, and PAC addition. EPRI [2019] also noted that the bromide concentration considered to be of concern by Regli et al. [2015] is below background levels in reference (least impacted) watersheds in many areas of the country.

Another uncertainty in the EPA's evaluation of bromide downstream impacts relates to the carcinogenic effects of TTHM, as incorporated into the Regli et al. [2015] analysis. The World Health Organization [WHO, 2017] concluded that THMs are noncarcinogenic in humans at concentrations found in drinking water. Cotruvo and Amato [2019] reported that there is poor correlation between THMs in drinking water and rates of bladder cancer across multiple countries and studies. The authors hypothesized that bladder cancer may be more closely associated with smoking prevalence; however, the extremely long latency time for bladder cancer initiation makes it very difficult to interpret the epidemiological data.

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 2

Comment Excerpt:

- Issues with EPA's cost-benefit analysis should be addressed, notably the failure to address discharges that could result in a downstream MCL violation.
- EPA should identify its work on bromide discharges on downstream utilities as a highly influential scientific assessment (HISA) and begin proper peer review and comment procedures.

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 9

Comment Excerpt:

EPA should revise its cost-benefit analysis to include benefits from avoiding MCL violations caused by or contributed to by bromide discharges, and the costs borne by utilities for increased bromide loads

On page 84 FR 64656, the proposal notes that "EPA's analysis quantifies the human health effects associated with incremental changes between the MCL and the MCLG" for total trihalomethanes. Although inclusion of this analysis is appreciated, its limitations create an inappropriate cost shifting from regulated NPDES dischargers to the downstream water utilities, in that the analysis only captures the benefits of reductions below the existing MCL, and does not capture the following:

- Health benefits from preventing MCL exceedances that would be contributed to from upstream discharges. Although the water system would be responsible for adding treatment or making operational changes to address an MCL violation for the purposes of coming back into compliance, even if an upstream discharge upstream discharge contributed to it, that does not eliminate the need to account for the impact caused by the discharge and the opportunity to reduce or eliminate it.
- The costs borne by downstream water systems (and consequently the public living downstream of regulated discharges) to address increased TTHMs, both costs in response to exceeding the MCL as well as costs to keep levels well below the MCL for the protection of public health and to reduce the possibility of a violation. This is especially important recognizing that the costs of treatment may exceed the health benefits of reducing brominated disinfection byproducts.

EPA should revise its cost-benefit analysis to address the above shortcomings. This more appropriate accounting will result in greater benefits of reducing bromide discharges (or conversely, greater costs of failing to reduce bromide discharges).

Commenter Name: G. Tracy Mehan, III
Commenter Affiliation: American Water Works Association (AWWA)
Document Control Number: EPA-HQ-OW-2009-0819-8312-A1
Comment Excerpt Number: 10

Comment Excerpt:

To ensure maximum transparency and accuracy of information used, EPA should pursue highly influential scientific assessment (HISA) procedures for analysis related to TTHMs.

On page 84 FR 64656, with regards to the analysis performed on the public health benefits of changing bromide discharges under the ELG (Table XII-3 and the information that supports it) the proposal notes that "should this analysis be used to justify an economically significant rulemaking, the EPA intends to peer review the analysis consistent with Office of Management and Budget's Information Quality Bulletin for Peer Review" and further goes on to indicate additional steps that may be taken "if the analysis is designated a highly influential scientific assessment (HISA)."

Unfortunately, the language in this section is contingent and the proposal does not currently suggest making these designations. Per the December 16, 2004 OMB bulletin on peer review[3], a scientific assessment should be classified as a HISA if at least one of the following are true:

- There is a potential impact of more than $500 million in any one year on either the public or private sector
- The assessment is novel, controversial, precedent-setting
- The assessment has significant interagency interest

The potential monetary impact of this analysis is enormous – per Table XII-3, the direct health impacts alone could total over $84 million on an annualized basis, and considering the potential under-counting discussed in our comments above, may be much greater. The costs across the public and private sectors could easily exceed "$500 million in any one year" due to the capital-intensive nature of installation of new treatment technologies in both the water an energy sectors that could be required to address these concerns. Given the ongoing concerns around the connection between discharges and impacts from bromide discharges, and the crossmedia and cross-sector nature of the concerns, the other two criteria are also met (therefore, even if the total costs are less than $500 million in all years, the criteria for a HISA are still met).

Therefore, EPA should designate this analysis as a HISA and begin the procedures for peer review, public comment, and other activities necessary to do so.

3 https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/memoranda/2005/m05-03.pdf

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 79

Comment Excerpt:

7. The Associated Health Risks are Uncertain.

The causal connection between TTHM and bladder cancer also has been called into question by a recent study. Issued in the spring of 2019, this study does not appear in the administrative record, is not referenced or cited in EPA's analysis, and may not have been considered by EPA when drafting the Proposed Rule. The article found that "[g]iven the long latency period, the difficulty in precisely defining exposure to TTHM exposure, and the multitude of confounding factors, it may be very difficult to identify the contributing bladder cancer risks in epidemiologic studies."[134] The study examined trends in incidence of bladder cancer in eight countries in the 45 years since TTHMs were detected in chlorinated drinking water. The "[n]ational trends in some countries showed increases in bladder cancer while TTHMs were either stable or decreasing; one country had higher TTHMs where bladder cancer was decreasing." Cotruvo and Amato (2019) at 15. Furthermore, the study found that:

[t]here are significant problems with attempting to correlate DBP chemicals in drinking water with potential low-risk chronic exposure health outcomes. The capability of traditional epidemiology studies to identify and quantify possible relationships between bladder cancer and TTHMs or other DBPs is limited because (1) latency periods for bladder cancer are not known, but lengthy; (2) the potential risks are likely small; and (3) long-term water composition and exposure contributors are so diverse and variable that exposure quantification requires major assumptions.

The latter is especially problematic. Distributed tap water DBP levels constantly change due to seasonal and system-specific variations and usage rates. Moreover, direct water consumption varies, and water composition changes occur during cooking and from uses in beverages and diet and are highly variable and difficult to quantify by recall surveys. Indirect sources also change the composition of at least some of the DBPs, that is, heating drives chemical reactions to completion and causes loss of volatiles. Exposures to some water components occur by inhalation during bathing, showering, and indoor air transmission. Dermal exposures to hydrophobic DBPs occur during bathing and showering. In addition, other significant exposures occur from chlorinated swimming pools, spas and therapy pools, immersion, inhalation at the water surface while swimming, dermal contact, incidental water ingestion, and from inhalation of volatiles from the air in indoor pool environments.

Id. at 14-15. Therefore, the relationship between DBP exposure and cancer risk remains unclear. EPA said as much in its 2006 Stage 2 Disinfectants and Disinfection Byproducts Rule. See 71 Fed. Reg. 388, 441 (Jan. 4, 2006) ("the existing epidemiological evidence has not conclusively established causality between DBP exposure and any health risk endpoints, so the lower bound of potential risks may be as low as zero.").

[134] Cotruvo, J.A. and H. Amato, *National Trends of Bladder Cancer and Trihalomethanes in Drinking Water: A Review and Multicountry Ecological Study,* at 15, DOSE-RESPONSE: AN INTERNATIONAL JOURNAL (Jan-Mar 2019) ("Cotruvo and Amato (2019)").

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 81

Comment Excerpt:

F. EPA's Estimated Bromide Reductions Contain Similar Errors.

EPA determined that, based on the estimated changes in the incidence of bladder cancer from exposure to TTHM due to the regulatory options and the value of benefits from avoided cancer cases, the annualized benefits from implementing regulatory options 2-4 ranges from $24 to $83 million per year.[137] EPA arrived at these numbers through a complex analysis involving multiple steps, which each contain various assumptions and uncertainties along the way. First, EPA estimated in-stream changes in bromide levels under each regulatory option. Then, EPA estimated the change in source water bromide levels at drinking water utilities and the corresponding changes in TTHM concentrations. Next, EPA assessed how the changes in concentration may impact the incidence of bladder cancers in the exposed population. And, lastly, EPA calculated the associated monetary value of the benefits.[138] EPA's analysis, however, contains a number of flaws that overestimate the amount of bromide that would reach downstream drinking water utilities, and it does not reflect the genuine uncertainty in the scientific literature associated with the risks of TTHM exposure.

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[137] BCA at 4-18.
[138] Id. at 4-4.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 84

Comment Excerpt:

Within this analysis, EPA does not appear to take into consideration the significant retirement of coal plants that will occur over the next 30 years. As noted above, by 2028, at least 78 plants (160 units) will either be retiring or converting to noncoal fuels between the summer of 2014 and December 31, 2028.[151] Further, coal consumption for U.S. electricity generation has declined by 26 percent from 2013 to 2018[152] and will continue to decline as coal-fired power plants close. As plants close or convert to non-coal fuels, the discharge of bromide will also decrease significantly. Nevertheless, the BCA does not appear to take into consideration this drop in bromide loadings between 2021 and 2047.

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[151] Supplemental TDD at 3-2 – 3-3.
[152] U.S. EIA, *Electricity Data Browser, Data Set – Consumption for Electricity Generation,* www.eia.gov/electricity/data/browser/#/topic (last visited Jan. 14, 2020).

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 85

Comment Excerpt:

4. EPA's Dilution Model Inaccurately Estimates Downstream Bromide Concentrations.

After calculating the bromide loadings from each facility, EPA used a dilution model to estimate pollutant concentrations downstream from the plants. The Downstream Fate and Transport Equations ("D-FATE") model involves calculating concentrations in each downstream water affected by steam electric power plant discharges using the United States Geological Survey's medium-resolution National Hydrography Dataset. The D-FATE model calculates the concentration of bromide in a given reach based on the total mass transported to the reach from upstream sources and the annual average Enhanced Runoff Method ("EROM") flows provided in version 2 of the NHDPlus dataset. While this model may be useful for evaluating impacts on a national scale, the data does not contain sufficient specificity for assessing the transport of bromide from specific power plants to corresponding downstream drinking water facilities.

According to EPRI, there are a few aspects of the model that could benefit from more site-specific information.[153] For example, the model assumes complete vertical and horizontal mixing of the discharge with the receiving waterbody, an error that becomes more pronounced at smaller scales. Also, under this analysis, the average distance from the steam electric discharge point to the drinking water treatment plant intake is approximately 40 miles.[154] At these distances, the quantity and the potential magnitude of a number of intervening factors is significant. Furthermore, the EROM uses meteorology data from 1971-2000. Thus, given changing precipitation patterns, projecting current or future outcomes may not be appropriate. Lastly, estimated flow was developed at a scale that is approximately equivalent to the second hydrologic unit code level ("HUC2"). This broad model is appropriate where uncertainty in flow is distributed equally across the area of evaluation, however, applying this model at a much smaller scale may lead to inaccurate flow estimates.

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[153] See EPRI 2020 Comments at 7-3.
[154] BCA at 4-6.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 86

Comment Excerpt:

5. EPA's Approach Does Not Reflect the Uncertainties in the Scientific Literature.

Finally, EPA relies on the results from Regli[155] to predict TTHM concentration changes for each water treatment plant[156] and to model the impact of changes in TTHM concentration in treated water on the lifetime bladder cancer risk. First, as Regli (2015) points out, and as EPA's data confirm, there is not a fixed relationship between bromide concentration and DBP formation; as the bromide concentration increases, proportionally less DBP may be formed due to limited natural organic matter precursors.[157] Also, as noted above, the Regli (2015) analyses are based on epidemiology studies from the 1980s and 1990s and may not reflect current disinfection practices, TTHM exposures, or the prevalence of other factors that cause bladder cancer.[158] More recent studies have shown that it is difficult to identify a causal connection between exposures to TTHM and bladder cancer. See, e.g., Cotruvo and Amato (2019).

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[155] S. Regli, et al., *Estimating Potential Increased Bladder Cancer Risk Due to Increased Bromide Concentrations in Sources of Disinfected Drinking Waters,* 49 ENVIRON. SCI. TECHNOL. 13094−13102 (2015), EPA-HQ-OW-2009-0819-7848 ("Regli (2015)").
[156] Id. at 4-9
[157] EPRI Bromide Report at 11-2; see also EPA, *Memorandum re: Case studies of changes in total trihalomethanes concentrations in treated water from public water systems downstream of steam electric power plants,* Attachments 1 and 2, EPA-HQ-OW-2009-0819-8125-Att1 and –Att2 (Oct. 28, 2019). The data attached to this memorandum presents TTHM concentrations in treated water supplies during monitoring periods preceding and following the installation of FGD systems located upstream from the drinking water facilities. While the data suggest consistent increases in levels of brominated THMs, the TTHM levels overall do not show a consistent increase, and in some places TTHM levels appear to decrease post-FGD installation.
[158] See EPRI Bromide Report at 8-3.

Commenter Name: Anonymous
Commenter Affiliation:
Document Control Number: EPA-HQ-OW-2009-0819-8461-A1
Comment Excerpt Number: 1

Comment Excerpt:

I wish to express my concerns regarding the analysis supporting this proposed rule. I understand the EPA's proposal from the standpoint that the agency is trying to reduce compliance costs by letting coal-fired facilities use more affordable technologies for water treatment, allowing them to stay competitive in the market, which in turn adds to domestic energy resilience. However, the bottom line is that this rule is relaxing some previously set environmental standards to reduce private industry costs, which is always a cause for careful consideration and evaluation.

It is clear to me that the total $137 million annual social costs savings only consider private industry compliance and government implementation costs compared to the 2015 Rule baseline. On the other hand, the corresponding total annualized health benefits of the proposed rule change are roughly $20 million, as presented in Table XII-8 (USEPA, 2019, pp. 64660). Therefore, the total annual net benefits of this benefit-cost analysis (B-C) are approximately $157 million, with 87% of net benefits realized by industry and government and 13% realized by those subjected to health effects, given the assumptions of the B-C with 3% discounting and EPA's preferred Option 2.

Looking closely at the water environmental impacts of this proposed change, a large portion of annual benefits are linked to reduced cancer risk from bromide discharge reduction. However, this is derived from estimated facility participation in the Voluntary Incentive Program (VIP), which is not actually required of any facilities and, therefore, is very uncertain (USEPA, 2019, pp. 64656). Additionally, the rule change would increase mercury exposure for children and a decrease the median water quality of potentially affected reaches. However, this decrease in water quality seems to get lost in the willingness-to-pay calculation, and somehow becomes a benefit, which needs to be more clearly explained or fixed if there is an error (USEPA, 2019, pp. 64655 & 64657). Considering these two categories make up all of the annualized health benefits makes me very concerned about how this B-C was conducted.

Furthermore, one of the arguments for this proposed rule change is that the original 2015 Rule is projected to result in the closure of coal-fired units that generate the equivalent of 1.8 GW, and this updated rule would result in a 0.7 – 1.1 GW net increase in coal-fired generating capacity from that baseline (USEPA, 2019, pp. 64643). As a researcher currently working on integrated air pollution and environmental economic modeling, I have particular concerns regarding the estimated annualized forgone benefits from changes in air emissions compared to the 2015 Rule, baseline scenario conducted in this B-C.

The proposed rule correctly considers that a net increase in coal-fired generating capacity would result in increased air pollution. However, Table XII-1 reveals that the human health benefits from changes in morbidity and mortality from exposure to NOx, SO2, and PM2.5 were 'Quantified but not monetized' in this analysis, indicating that they are not included in the B-C results (USEPA, 2019, pp. 64654). This is a problem as increases in NOx, which will affect tropospheric O3 concentrations, increases in SO2 emissions, which will increase secondary PM2.5 concentrations, and increases in primary PM2.5 emissions all pose a serious risk to human health. Clearly, the social costs associated with these three pollutants from coal-fired facilities would affect the B-C associated with the rule, and I do not accept "air quality modeling is needed [...] the EPA's modeling capacity was fully allocated to supporting other regulatory and policy efforts" (USEPA, 2019, pp. 64658) as a sufficient reason to not include these impacts when considering the health effects of decreasing environmental standards.

I must also express my opposition to the assumptions made for the avoided climate change impacts from CO2 emissions in the B-C for this proposed rule. The social cost of carbon estimate for this analysis is significantly less than the widely supported estimates of approximately $50 per ton (Environmental Defense Fund, n.d.). The documentation and a brief analysis I conducted indicate that between $1-7 per ton was used. As many folks at the EPA know, CO2 is a well-mixed pollutant, meaning that a ton of CO2 emitted within the U.S. has the same environmental impact globally as it does domestically. Focusing on the "domestic social cost of carbon" is depreciating the welfare of international people because of their distance from the U.S. This is unjust as this decision does not consider all of the costs that will be incurred by climate change globally that we are imposing. Moreover, effects of climate change are already being realized domestically (e.g. increases in extreme weather event frequency), and the economic impacts are and will continue to be significant. Climate change is the greatest geopolitical threat we face today, and it deserves proper consideration in analyses for decisions affecting the environment.

I investigated this proposed rule's B-C by remodeling it and adjusting the inputs given the discussion above. I included social costs of SO2 and NOx of approximately $7,000 and $2,000 per ton, respectively. These estimates were gathered from the book "Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use" published by the National Academy of Sciences, which provides average estimates of monetary damages per ton of emissions from coal-fired power plant (National Research Council, 2010, pp. 90). I also changed the social cost of carbon from the approximately $7 domestic estimate to the global estimate of $50. Using a 3% discount rate and the other inputs from this proposed rule's Option 2, I found that the annual net benefits of this rule are about -$136 million. This results in a 2047 net present value not of $3 billion in benefits, as the EPA's B-C demonstrates, but instead of approximately $2.5 billion in costs. Given a brief sensitivity analysis, including the social costs of local air pollution as I have, the EPA would only need to use 50% of the global social cost of carbon (about $25/ton) for this proposed rule to result in no net benefits over the timeline considered. It is notable that this analysis does not even address direct PM2.5 emissions from the coal-fired facilities as no emissions estimates were provided by the EPA, indicating that these calculated costs may still be underestimated.

In conclusion, I believe this analysis deserves further attention before this proposed rule goes through. Given that I used the EPA's inputs for the majority of the analysis I conducted, only altering the air quality cost elements, my methodology should be sound from the EPA's perspective. While my results are uncertain, they indicate that, given proper air quality pollution costs, this proposed rule's net benefits are lower than is reported. I am requesting the EPA reconduct this analysis to include local air pollution and the proper global social cost of carbon.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 70

Comment Excerpt:

IX. PROPOSED OPTIONS FOR ADRESSING BROMIDE DISCHARGES DO NOT REFLECT USE OF BAT AND WILL NOT PROTECT PUBLIC HEALTH.

A. The Record Shows Public Health Benefits of Controlling Bromide Discharges from Power Plants are Significant.

Coal-fired power plants discharge a significant amount of bromide into surface waters every year. Bromide is naturally present in all coal but some plant operators burn coal refined with bromide and/or inject bromide during combustion to reduce mercury air emissions.[240] EPA's review of the literature on bromide, summarized in the Supplemental Environment Assessment ("Proposed EA"), identified numerous studies that have documented elevated bromide levels in surface waters downstream of coal plants.[241] EPA's literature review also showed that levels of bromide in FGD wastewater can exceed 175 mg/L.[242] As part of the record for this proposed rulemaking, EPA estimated bromide loadings from seventy coal plants and found that concentrations of bromide in untreated FGD wastewater from plants that do not add bromide or burn refined coal average 59.1 mg/L, while bromide concentrations average 167 mg/L for plants that do add bromide or burn refined coal.[243] EPA also estimated that bromide concentrations in bottom ash wastewater discharges average 5.1 mg/L.[244] Estimated average bromide concentrations in FGD wastewater and in bottom ash transport water are much higher than estimated average background levels in fresh surface waters, which range from 0.014 mg/L to 0.2 mg/L.[245]

Though the presence of bromide in fresh surface waters is not believed to impact aquatic ecosystems or pose a risk to human health, low concentration of bromide present in drinking water sources can become a public health risk because it is a precursor for the formation of trihalomethanes (THMs), which are known carcinogens.[246] These disinfectant byproducts (DBPs) can form when bromide reacts with common drinking water disinfectants used to control microbial pathogens. As described in the Proposed EA, several studies have "documented evidence of a linkage between DBP exposure and bladder cancer and, to a lesser degree, colon and rectal cancer, other cancers, and reproductive and developmental effects."[247] A 2015 study estimated that a 0.05 mg/L increase in raw water bromide concentrations could result in a lifetime excess bladder cancer risk of up to one in a 1,000.[248]

Because of these known human health risks from DBP exposure, drinking water systems have to maintain a running average Maximum Contaminant Level (MCL) of 80 ug/L for total THMs in finished drinking water.[249] EPA has also established health-based goals for some individual THMs, known as MCL Goals (MCLGs), which are the levels at which no known or expected risks to human health exist.[250] For some DBPs, there are "no safe levels," meaning any detectable level in finished drinking water poses a health risk.[251] The Proposed EA cites several studies that have documented elevated bromide levels at drinking water intakes downstream of coal plants discharging FGD wastewater and additional studies that have correlated increases in DBPs at drinking water systems with increases in upstream bromide discharges.[252]

Chapter 4 of the Proposed Benefit and Cost Analysis describes the impacts elevated bromide levels can have on drinking water systems and quantifies some of the human health benefits of reducing bromide discharges from coal plants. EPA estimated that 31.4 million people are potentially impacted by these discharges.[253] EPA then quantified the estimated number of avoided bladder cancer cases and associated monetary benefits under the four proposed regulatory options.[254] Option 4 (membranes as BAT for FGD wastewater) was estimated to avoid 769 bladder cases, more than twice as many as under Option 2 and nearly twice as many as under Option 3, at an estimated benefit of $54.3 to $84.3 million dollars.[255] However, the number of avoided bladder cancer cases is likely an underestimate because EPA only quantified the health benefits of incremental changes in DBP levels between the MCL and MCLGs.[256] EPA limited its analysis because the agency concluded the drinking water systems that would most benefit from reducing bromide discharges coming from coal plants have total THM levels below the MCL but above the MCLGs for individual trihalomethanes.[257] EPA's analysis is flawed because it does not capture the public health benefits of preventing MCL violations. Though drinking water systems would be required to adjust their treatment or make operational changes to address MCL violations, there are quantifiable benefits to drinking water systems in the form of avoided treatment costs. EPA claims "it did not have data on drinking water treatment technologies at potentially impacted Public Water Systems or cost estimates for those technologies," yet the agency could have collected this data.[258] As part of its benefit-cost analysis EPA identified 26 Public Water Systems "that together account for approximately 70 percent of estimated benefits for proposed Options 2 and 4."[259] EPA should have requested cost estimates for different drinking water treatment technologies from these potentially impacted systems. Moreover, there remain significant benefits to the public in the form of reduced bladder cancer risk, as any changes made in response to an MCL violation would only occur after that violation was detected and reported and after any delay in returning to compliance. During the interim period, which could realistically be months or years, the public would be exposed to egregiously high levels of THMs and would experience elevated cancer risks. In addition, as described in the Proposed EA, some DBP treatment options used to come into compliance with the THM MCL may not actually reduce total risks to human health.[260] EPA should expand its analysis to account for these avoided treatment costs and human health benefits.

The record before EPA clearly demonstrates the significant impact bromide wastewater discharges from coal plants have on downstream drinking water systems and the tremendous human health benefits of controlling this pollution. One of the greatest human health benefits quantified in this proposal is the number of bladder cancer cases that would be avoided from reducing bromide discharges. EPA should act on the findings in its own analysis and revise its proposal to require limits on bromide discharges in FGD wastewater.

240 Proposed TDD at 3-6.
241 Proposed EA at 2-4.
242 *Id*.
243 ERG, Mass Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants – DCN SE07260, Docket ID. No. EPA-HQ-OW-2009-0819-8242 (Oct. 2019).
244 Proposed TDD at 6-13, Tbl. 6.2.
245 Proposed EA at 2-4.
246 S. Regli et al., Estimating Potential Increased Bladder Cancer Risk Due to Increase Bromide Concentrations in Sources of Disinfected Drinking Waters, Envtl. Sci. & Tech., 49(22):13094-13102, DCN SE07927, Docket ID No. EPA-HQ-OW-2009-0819-7848 (2015) ("S. Regli *et al*. (2015)").
247 Proposed EA at 2-5.
248 S. Regli et al. (2015).
249 *Id*. at 2-6, Tbl. 2-1.
250 *Id*. at 2.5, 2.6, Tbl. 2-1.
251 Proposed BCA at 2-5, Tbl. 2-2.
252 Proposed EA at 2-6.
253 Proposed BCA at 4-6, Tbl. 4.1.
254 *Id*. at 4-18, Tbl. 4-7.
255 *Id*.
256 *Id*. at 4-3.
257 *Id*.
258 BCA at 2-12.
259 EPA, Compliance With Total Trihalomethanes Standards at Selected Public Water Systems Downstream of Steam Electric Power Plants – DCN SE07792, Docket ID. No. EPA-HQ-OW-2009-0819-8168 (Oct. 2019).
260 Proposed EA at 2-5.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 22

Comment Excerpt:

Importantly, the human health benefits are also significantly greater under Option 4, even considering that in its health costs analysis, EPA inappropriately credits Option 2 with the benefits of bromide reductions that it claims will be achieved by membrane filtration, the basis for the Voluntary Incentives Program. This is a serious mistake—Option 2, for which BAT is chemical precipitation followed by low-residence time biological treatment and ultrafiltration, does not include the membrane filtration that is responsible for these health benefits. Even with EPA's faulty assumptions that inflate the health benefits for Option 2, Option 4 would achieve more than twice the human health benefits of Option 2.[35]

...

Its proposed approach, Option 2, must be evaluated based on the pollution controls Option 2 actually requires—not on the possibility that utilities might voluntarily adopt a more protective approach that is not actually required by EPA's proposed rule.

[35] See 84 Fed. Reg. at 64,656.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 16

Comment Excerpt:

IV. EPA's Assessment of the Proposed Rule's Cost-Benefit Analysis Is Fundamentally Flawed.

EPA claims that the Proposed Rule's benefits will outweigh its costs, relative to the 2015 Rule.[99] This assertion, however, is based on a mix of crucial assumptions that are either inaccurate or unexplained.

To evaluate the costs and benefits of the Proposed Rule, EPA considers the compliance costs of the Proposed Rule relative to the 2015 Rule, and the health and environmental benefits of the Proposed Rule relative to the 2015 Rule. Unsurprisingly, the Proposed Rule requires lower compliance costs than the 2015 Rule required, yielding compliance cost savings of $146.5 million annually using a 7% discount rate, according to EPA.[100] More counterintuitively, however, EPA also claims that the Proposed Rule will realize health and environmental benefits relative to the 2015 Rule, ranging from $28.4 million to $74.4 million annually, again using a 7% discount rate.[101]

This improbable result—that a rule slashing environmental standards will increase health and environmental benefits—is achieved through a variety of flawed assumptions.

A. EPA Undervalues the Proposed Rule's Forgone Benefits Associated with Climate Change

To begin, EPA downplays the effect the rule will have upon climate change. The agency acknowledges that relaxing the compliance costs for coal may affect the nation's "electricity generation profile," increasing the amount of energy contributed by coal as compared to the 2015

Rule.[102] This change, in addition to projected energy use changes, will lead to an increase in carbon dioxide emissions,[103] EPA predicts. In the words of the agency, carbon dioxide "is the most prevalent of the greenhouse gases, which are air pollutants EPA has determined endangers public health and welfare through their contribution to climate change."[104]
Because the 2015 Rule was projected to reduce carbon dioxide emissions relative to the Proposed Rule, the increased emissions represent a forgone benefit that cuts against adopting EPA's proposed regulation. But the agency severely understates the value of this forgone benefit.[105] The agency predicts that the Proposed Rule will result in $5.2 million to $31.6 million in annual forgone climate-related benefits, depending on the discount rate.[106] If properly valued, these forgone benefits would be much greater. For further discussion of this issue, see Policy Integrity's separate comments on the social cost of carbon, filed jointly with several other organizations.[107]

B. EPA Irrationally Assumes VIP Benefits Will Outweigh the Negative Health and Environmental Effects of the Proposed Rule
Climate impact is not the only area in which the Proposed Rule produces significant forgone benefits relative to the 2015 Rule. In fact, the Proposed Rule performs worse on virtually every environmental and health metric EPA examined. Of the 14 water pollutants the rule is supposed to regulate, the Proposed Rule increases the annual release of 13.[108] The Proposed Rule will also increase IQ losses in children exposed to mercury.[109] Dredging costs will increase under the Proposed Rule[110] because of an increase in total suspended solids discharged by power plants to national waterways.[111] And these poor results apply only to forgone benefits the agency attempts to quantify; other environmental impacts, like harms to endangered species, EPA only qualitatively describes, [112] though the results are also dismal.[113]

Given all these harms, EPA's claim that the Proposed Rule will yield net health and environmental benefits relative to the 2015 Rule evidently rests entirely on one change: a new limitation for bromide that EPA has introduced as part of the "voluntary incentive program, or "VIP."[114] The only health benefit the agency predicts from the Proposed Rule, relative to the 2015 Rule, is a decrease in bladder cancer resulting from decreased bromide exposure.[115] EPA values this benefit as $24.41 to $37.61 million annually, depending on the discount rate.[116] This ostensible benefit is large enough to cancel out the negative human health effects of other aspects of the Proposed Rule and results in a supposed net benefit to human health of $23.6 to $34.8 million annually, relative to the 2015 Rule.[117] The agency couples this benefit with a supposed increase in "ecological conditions and recreational uses" of $14.3 million to $16.7 million annually.[118] Because this value is based on the estimated household's willingness to pay for water quality,[119] this benefit presumably also derives from the expected decrease in bromide release. The Proposed Rule decreases the quality of water with respect to every other type of pollutant, so the only reason the willingness to pay could possibly be higher for the Proposed Rule relative to the 2015 Rule is a lower bromide level. Taken together, the human health benefits and ecological condition benefits associated with bromide reduction allow EPA to claim the Proposed Rule yields net health and environmental benefits relative to the 2015 Rule,[120] notwithstanding all of the metrics upon which the Proposed Rule performs poorly relative to the prior regulation. Thus the Proposed Rule's benefits all depend on EPA's rosy assumption that 18 facilities will opt into the VIP.[121] This has three important consequences:

First, because VIP controls are not triggered until the end of 2028, all of the health and environmental effects of the Proposed Rule are likewise delayed. Indeed, EPA acknowledges that measuring "average annual [benefits] instead of a year-by-year profile masks potential transitional effects of the regulatory options, including temporary increases in [pollution] relative to the 2015 final rule."[122] EPA does not discuss what the health and environmental effects of this period of heavier pollution might be. Moreover, EPA does not seem to acknowledge or consider that, outside of the VIP, all of the agency's proposed BAT/PSES limitations lead to significant health and environmental forgone benefits relative to the 2015 Rule. EPA is required to address the forgone benefits of delaying these protections.[123] The agency must examine the effects of delaying health and environmental benefits until the end of 2028 and explain why BAT/PSES limitations that yield no such benefits are "best" at making "reasonable further progress" toward eliminating pollutants.

This shortcoming reveals a second flaw in EPA's analysis. Just as EPA should analyze the statutory BAT factors at the individual BAT level, the agency should conduct cost-benefit analyses at the individual BAT level. The reasons are similar: Just as the positive effects of one BAT may mask the negative effects of another BAT, so too may the costs or benefits of one BAT mask those of another. Thus, EPA should conduct a cost-benefit analysis for each BAT, rather than conducting a cost-benefit analysis for each regulatory option, which bundles BAT limitations with the VIP. Otherwise, the agency may set BATs that yield more forgone benefits than they save in compliance costs. Setting a BAT with forgone benefits that outweigh compliance cost savings is arbitrary and capricious.[124]

Third, because bromide reductions are triggered only by enrollment in the VIP, if EPA's prediction overstates the number of facilities that will voluntarily opt into more stringent standards by the end of 2028, then EPA overstates the bromide-related benefits of the Proposed Rule.

99 See id. at 64,622 (summarizing the decrease in "social costs" and increase in "benefits" relative to a baseline reflecting the 2015 Rule).
100 RIA at ES-2.
101 BAC at 11-3.
102 Id. at 8-1.
103 Id. at 8-9.
104 Id. at 8-1.
105 See id. at 8-6 to 8-7 (discussing value of the social cost of carbon and arriving at very low values).
106 Id. at 8-9.
107 Inst. for Pol'y Integrity et al., Comment Letter on Flawed Monetization of Forgone Benefits in the Proposed Rule, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Jan. 21, 2020).
108 See id. at 3-6 (displaying "total" annual average changes in discharge relative to the baseline for Option 2).
109 Id. at ES-2.
110 Id.
111 Id. at 10-1.
112 See id. at 7-6 (describing the inability to quantify or monetize these harms).
113 See id. (showing 27 threatened and endangered species whose habitats may be adversely affected by the Proposed
Rule, compared to zero such species under the 2015 Rule).

114 See id. at 3-6 (showing bromide as the only pollutant whose totals are expected to decrease under the Proposed Rule relative to the 2015 Rule).
115 See id. at ES-2 & 4-18 (providing total health benefits and total annual benefits of decreased bladder cancer, respectively).
116 Id. at 4-18.
117 Id. at ES-2 to ES-3.
118 See id. at ES-2 to ES-3 (showing the mid value for option 2 for a 3% and 7% discount rate).
119 Id. at 6-3.
120 Id. at ES-2.
121 Id. at 2-1.
122 Id. at 3-3.
123 Air Alliance Houston v. EPA, 906 F.3d 1049, 1068 (D.C. Cir. 2018).
124 Nat'l Ass'n of Home Builders v. EPA, 682 F.3d 1032, 1040 (D.C. Cir. 2012) (saying a "serious flaw undermining" the agency's cost-benefit analysis "can render the rule unreasonable").

Commenter Name: Bethany Davis Noll
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Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 18

Comment Excerpt:

In sum, EPA significantly understates the forgone benefits associated with switching from the 2015 Rule to the Proposed Rule. EPA undervalues the social cost of carbon and thus underestimates the Proposed Rule's climate impacts. And the only benefits associated with the

Proposed Rule rely on unjustified assumptions about enrollment in the VIP and likely overstate the program's benefits. If the Proposed Rule's forgone benefits were correctly valued, they would likely outweigh the decreased compliance costs associated with the Proposed Rule, demonstrating how unjustified the Proposed Rule is.

Commenter Name: Iliana Paul
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Document Control Number: EPA-HQ-OW-2009-0819-8467-A1
Comment Excerpt Number: 1

Comment Excerpt:

EPA forecasts that the proposed deregulation will lead to the significant increases in greenhouse gas emissions: for example, in its preferred Option 2, of over 104 million additional metric tons of carbon dioxide from changes in domestic electricity generation over the years 2021 to 2047.[2] The deregulation will also result in increases in emissions of nitrogen oxides, sulfur dioxide,[3] other air pollutants,[4] and a host of water pollutants.[5] EPA justifies these substantial emissions increases by asserting that the preferred option[6] will yield cost savings to industry as well as certain alleged health and environmental benefits.[7] However, this result depends in large part on a change in EPA's methodology that drastically— and inappropriately—reduces the agency's estimate of the social cost of carbon emissions.

In fact, by decreasing the social cost of carbon by more than 85%,[8] EPA has now disregarded significant climate and public-health costs that the agency properly accounted for in the 2015 Rule. As detailed below, the agency's revised estimate of the social cost of carbon is completely inconsistent with the best available science, best practices for economic analysis, and legal standards for rational decision making. Had the agency properly accounted for the social costs of carbon emissions to appropriately calculate the full forgone benefits using the best available science and economics—as it did in the 2015 Rule—it would

have recognized that the proposed deregulation causes far more harm than good, and is therefore not a rational exercise of the agency's discretion. These comments make the following main arguments about how EPA failed to appropriately value the social cost of carbon and other forgone benefits:

- EPA arbitrarily attempts to limit its valuation of the social cost of carbon to domestic-only effects. Not only is a global perspective required under principles of rational decision making, but the methodology and models that EPA uses cannot calculate an accurate domestic-only value.
- EPA arbitrarily discounts future climate effects at a 7% discount rate in addition to a 3% rate. Applying a 7% discount rate to inter-generational effects is inconsistent with Circular A-4's requirements to distinguish social discount rates from rates based on private returns to capital; to make plausible assumptions; to adequately address uncertainty, especially over long time horizons; and to rely on the best available economic data and literature.
- EPA arbitrarily fails to follow prescribed practices for dealing with uncertainty. Specifically, EPA fails to address uncertainty over catastrophic damages, tipping points, option value, and risk aversion (by, for example, giving appropriate weight to an estimate of the social cost of carbon at the 95th percentile). By failing to run such sensitivity analyses, EPA overlooks how different (and more plausible) assumptions would change its cost-benefit calculation.
- EPA uses "interim values" of the social cost of carbon that advance its predetermined goal of a lower social cost of carbon. Any update to the Interagency Working Group's 2016 estimates must fully engage with all the most up-to-date literature and with all the recommendations issued by the National Academies of Sciences.
- EPA fails to appropriately value unquantified foregone benefits to climate and public health or incorporate monetized forgone benefits that are readily available into its cost benefit analysis.

These critical failings completely undercut, and reverse the outcome of, the cost-benefit assessment that accompanies the proposed deregulation. In fact, according to EPA's own calculations using a global estimate of the social cost of carbon at a 3% discount rate—which are buried in technical appendices and spreadsheets—the annualized forgone climate benefits of Option 2 are $232.8 million per year, which is over $200 million per year more in climate damages than EPA reports in its main cost-benefit analysis.[9] Those additional forgone benefits would erase the cost savings and other benefits that EPA claims for Option 2.[10] EPA's failure to explain either its inappropriate focus on domestic-only calculations of the social cost of carbon or its inclusion of calculations based on a 7% discount rate, underscores that the proposal is arbitrary and capricious, particularly given that a proper analysis of forgone climate effects would reverse the agency's cost-benefit analysis.

1 84 Fed. Reg. 64,620 (Nov. 22, 2019).
2 BCA at 8-4, table 8-4 (listing estimated emissions by year due to changes in electricity generation, net of changes in power requirements and trucking). Use of EPA's estimates here is for illustrative purposes and does not endorse EPA's estimates as accurate or complete.
3 *Id.*
4 *Id.* at 8-11.
5 *Id.* at 3-6.
6 *See Id.* at ES-1, Tbl. ES-1: Regulatory Options.
7 *Id.* at ES-3 to ES-4 (claiming cost savings as well as decreased cancer risks and water quality benefits in most scenarios); *but see id.* at 12-1 ("As shown in the table, the regulatory options generally result in cost savings across the four options and discount rates, with the exception of Option 4 which results in incremental costs at 3 percent discount rate."); *see also* 84 Fed. Reg. at 64,622.
8 *Compare* BCA at 3-10 ($8 social cost of carbon in 2030, in 2018$ and discounted at 3 percent) *with* EPA, Benefit and Cost Analysis for Steam Electric Power Generating ELGs (Sept. 2015) (hereinafter "2015 BCA") ($55 social cost of carbon in 2030, in 2013$ and discounted at 3 percent).
9 EPA-HQ-OW-2009-0819-8162 (showing CO2Benefit_GlobalSCC versus CO2Benefit_DomesticSCC); *see also id.* (showing annualized forgone benefits of $337.5 million at a 2.5% discount rate); *see also* BCA at 1-5 to 1-6 (presenting global estimates for select years, but not an annualized or total figures).
10 *See* BCA at ES-4, showing a mid-range estimate of $155.9 million in annualized cost savings and benefits at a 3% discount rate, or $198.8 million in annualized cost savings and benefits at a 7% discount rate. In either case, properly applying the central estimate of global climate effects would increase forgone climate effects by over $200 million, enough to exceed those figures. As for EPA's alleged high-range estimate of benefits, a proper comparison of forgone climate benefits would reflect either the Interagency Working Group's 95th percentile high-impact estimate or the central social cost of carbon calculated at a 2.5% discount rate, and again the annualized forgone climate benefits would exceed EPA's calculations.

Commenter Name: Iliana Paul
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Document Control Number: EPA-HQ-OW-2009-0819-8467-A1
Comment Excerpt Number: 2

Comment Excerpt:

1. EPA's Revised Valuation of the Social Cost of Carbon Severely—and Arbitrarily—Undervalues the Proposed Deregulation's Significant Climate Costs

Standards of rationality require attention to and consistent treatment of important factors. To the extent that EPA seeks to justify its proposed deregulation by comparing cost savings to forgone benefits, EPA's estimates of forgone benefits overlook a host of important factors like climate spillovers, international reciprocity, extraterritorial interests, intergenerational equity, uncertainty over long-term growth, uncertainty over catastrophic outcomes, risk aversion, option value, and unquantified effects to climate and health. Executive Order 13,783 does not, and cannot, change EPA's legal obligations to appropriately weigh forgone benefits. Moreover, Executive Oder 13,783's disbanding of the Interagency Working Group ("IWG") does nothing to change the fact that the IWG's 2016 estimates of the social cost of carbon reflect the best available data and methods. As such, EPA should use the Interagency Working Group's estimates when assessing the climate costs of the proposed deregulation, just like it did when it issued the 2015 Rule.

Commenter Name: Iliana Paul
Commenter Affiliation: Institute for Policy Integrity at New York University School of Law, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8467-A1
Comment Excerpt Number: 3

Comment Excerpt:

A. EPA Must Monetize the Full Social Cost of Carbon, Using the Best Available Data and Methodologies

The Administrative Procedure Act requires the EPA to use the best available data and methodologies to account for the social cost of greenhouse gases. This mandate continues to remain in effect following the issuance of Executive Order 13,783: Indeed, agencies must continue to monetize the social cost of greenhouse gases using the best available science, as that order recognizes, and the IWG's 2016 estimates of the social cost of carbon reflect the best available data and methods.

Standards of Rationality Requires Attention to and Consistent Treatment of Important Factors

The Supreme Court defined the standard of rationality for agency actions under the Administrative Procedure Act as follows:

Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider, **entirely failed to consider an important aspect of the problem,** offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view of the product of agency expertise.[11]

Furthermore, the Court found that the standard requires agencies to "examine the relevant data and articulate . . . a rational connection between the facts found and the choice made."[12]

Two federal courts of appeals have already applied arbitrary and capricious review to require the use of the social cost of greenhouse gases in agency decision-making.[13] In *Center for Biological Diversity v. National Highway Traffic Safety Administration*, the U.S. Court of Appeals for the Ninth Circuit ruled that, because the agency had monetized other uncertain costs and benefits of its vehicle fuel efficiency standard, its "decision not to monetize the benefit of carbon emissions reduction was arbitrary and capricious."[14] Specifically, it was arbitrary to "assign[ ] no value to *the most significant benefit* of more stringent [vehicle fuel efficiency] standards: reduction in carbon emissions."[15] When an agency bases a rulemaking on cost-benefit analysis, it is arbitrary to "put a thumb on the scale by undervaluing the benefits and overvaluing the costs."[16]

More recently, in *Zero Zone Inc. v. Department of Energy*, the U.S. Court of Appeals for the Seventh Circuit approved of the Department of Energy's use of the IWG's SCC estimates, holding that that "the expected reduction in environmental costs *needs* to be taken into account" in order for the Department "[t]o determine whether an energy conservation measure is appropriate under a cost-benefit analysis."[17] Furthermore, the court specifically rejected petitioner's challenge to the Department's use of a global (rather than domestic) social cost of carbon, holding that Department had reasonably identified carbon pollution as "a global externality" and appropriately concluded that, because "national energy conservation has global effects, . . . those global effects are an appropriate consideration when looking at a national policy."[18]

Two federal district courts have also found the failure to use the social cost of carbon in NEPA analyses to be arbitrary and capricious when—like EPA's regulatory analysis here—those same analyses also quantified economic benefits. In *High Country Conservation Advocates v. Forest Service*, the U.S. District Court for the District of Colorado found that it was "arbitrary and capricious to quantify the *benefits* of the lease modifications and then explain that a similar analysis of the *costs* was impossible when such an analysis was in fact possible"—specifically, by applying the "social cost of carbon protocol."[19] In *Montana Environmental Information Center v. Office of Surface Mining*, the U.S. District Court for the District of Montana followed the lead set by *High Country* and likewise held an environmental assessment to be arbitrary and capricious because it quantified the benefits of action while failing to use the social cost of carbon to quantify the costs.[20]

In short, agencies must monetize important greenhouse gas effects when their decisions are grounded in cost-benefit analysis.[21]

A Recent Executive Order Encourages Continued Monetization of the Social Cost of Greenhouse Gases

Executive Orders 12,866 and 13,563 remain in effect[22] and continue to require agencies to weigh the costs and benefits of significant regulatory actions. In particular, Executive Order 12,866 requires agencies to "select those approaches that maximize net benefits (including potential economic, *environmental, public health* and safety, *and other advantages*; distributive impacts; and equity), unless a statute requires another regulatory approach."[23] For significant regulatory actions, agencies must quantify costs and benefits to the fullest extent feasible.[24] The Interagency Working Group on the Social Cost of Greenhouse Gases was specifically organized to develop a single, harmonized value for all agencies to use in their regulatory impact analyses under Executive Order 12,866.[25]

President Trump's Executive Order 13,783, issued March 28, 2017, officially disbanded the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) and withdrew the technical support documents that underpinned their range of estimates.[26] Nevertheless, Executive Order 13,783 assumes that federal agencies will continue to "monetiz[e] the value of changes in greenhouse gas emissions" and instructs agencies to ensure such estimates are "consistent with the guidance contained in OMB Circular A-4."[27] Consequently, while EPA and other federal agencies no longer have technical guidance directing them to exclusively rely on the IWG's estimates to monetize climate effects, by no means does the new Executive Order imply that agencies should not monetize important effects in their regulatory analyses or environmental impact statements. In fact, Circular A-4 instructs agencies to monetize costs and benefits whenever feasible.[28]

The 2017 Executive Order does not prohibit agencies from relying on the same choice of models as the IWG, the same inputs and assumptions as the IWG, the same statistical methodologies as the IWG, or the same ultimate values as derived by the IWG. To the contrary, because the Executive Order requires consistency with Circular A-4, as agencies follow the Circular's standards for using the best available data and methodologies, they will necessarily choose similar data, methodologies, and estimates as the IWG, since the IWG's work continues to represent the best available estimates.[29] The new Executive Order does not preclude agencies from using the same range of estimates as developed by the IWG, so long as the agency explains that the data and methodology that produced those estimates are consistent with Circular A-4 and, more broadly, with standards for rational decision making.

As explained throughout these comments, the IWG's estimates of the social cost of greenhouse gases are, in fact, already consistent with the Circular A-4 and represent the best existing estimates of the lower bound of the range for the social cost of greenhouse gases. Therefore, the IWG estimates or those of a similar or higher value[30] should be used in regulatory analyses and environmental impact statements.

11 *Motor Vehicle Manufacturers Assoc. v. State Farm Mutual Auto. Ins. Co*., 463 U.S. 29, 41-43 (1983) (emphasis added); *see also id.* ("[W]e must 'consider whether the decision was based on a consideration of the relevant factors and whether there has been a clear error of judgment.'").
12 *Id.*
13 A few courts have also applied arbitrary and capricious review to the use or non-use of the social cost of carbon in environmental impact statements under the National Environmental Policy Act. In *High Country Conservation Advocates v. Forest Service*, the U.S. District Court of Colorado found that it was "arbitrary and capricious to quantify the *benefits* of the lease modifications and then explain that a similar analysis of the *costs* was impossible when such an analysis was in fact possible"— specifically, by applying the IWG's Social Cost of Carbon protocol. 52 F. Supp. 3d 1174, 1191 (D. Colo. 2014). The U.S. District Court of Oregon declined to follow suit in *League of Wilderness Defenders v. Connaughton*, but only because in that case the Forest Service had not conducted a quantitative analysis of either costs or benefits of climate change but rather addressed climate change qualitatively. No. 3:12-cv-02271-HZ, decided Dec. 9, 2014.
14 538 F.3d 1172, 1203 (9th Cir. 2008).
15 *Id.* at 1199.
16 *Id.* at 1198.
17 832 F.3d 654, 677 (7th Cir. 2016).
18 *Id.* at 679.
19 52 F. Supp. 3d 1174, 1191 (D. Colo. 2014) (emphasis original).
20 274 F. Supp. 3d 1074, 1094–99 (D. Mont. 2017) (also holding that it was arbitrary to imply that there would be zero effects from greenhouse gas emissions).

21 *See generally* Peter Howard & Jason Schwartz, *Think Global: International Reciprocity as Justification for a Global Social Cost of Carbon*, 42 COLUMBIA J. ENVTL. L. 203 (2017) for more on applying standards of rationality to the social cost of carbon.
22 *See* Exec. Order No. 13,777 § 2 (Feb. 24, 2017) (continuing to cite the policies required under Executive Orders 12,866 and 13,563).
23 Exec. Order 12,866 § 1(a) (Oct. 4, 1993).
24 *Id.* § 6(a)(3)(C)(i).
25 Interagency Working Group on Social Cost of Carbon, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis (2010). Though note the IWG's estimates are applicable in a wider range of contexts, including environmental impact statements. *See, e.g.*, *High Country*, 52 F. Supp. 3d at 1190; *Montana Environmental,* 274 F. Supp. 3d at 1095.
26 Exec. Order. No. 13,783 § 5(b), 82 Fed. Reg. 16,093 (Mar. 28, 2017).
27 *Id.* § 5(c).
28 OMB, Circular A-4 at 27 ("You should monetize quantitative estimates whenever possible.").
29 Richard L. Revesz et al., *Best Cost Estimate of Greenhouse Gases*, 357 SCIENCE 6352 (2017) (explaining that, even after Trump's Executive Order, the social cost of greenhouse gas estimate of around $50 per ton of carbon dioxide is still the best estimate).
30 *See*, *e.g.*, Richard L. Revesz et al., *Global Warming: Improve Economic Models of Climate Change*, 508 NATURE 173 (2014) (explaining that current estimates omit key damage categories and, therefore, are very likely underestimates).

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B. EPA Must Rely on a Global Estimate of the Social Cost of Carbon

EPA claims that Circular A-4 requires a "domestic perspective in our central analysis"[31] and therefore buries any discussion of global climate damages in an appendix. EPA is wrong. Not only is it inconsistent with Circular A-4 and best economic practices to fail to estimate the global damages of U.S. greenhouse gas emissions in regulatory analyses, but existing methods for estimating a "domestic-only" value— including EPA's approach here—are unreliable, incomplete, and inconsistent with Circular A-4. EPA's domestic-only estimate inappropriately relies on models never built for the purpose of calculating regional damages, ignores recent literature on significant U.S. climate damages, and fails to reflect international spillovers to the United States, U.S. benefits from foreign reciprocal actions, and the extraterritorial interests of U.S. citizens including financial interests and altruism.

Standards of Rational Decision making, As Articulated in Case Law and Executive Guidance, Require Consideration of Global Climate Damages

As noted above, the Administrative Procedure Act, as interpreted by the Supreme Court in *State Farm*, requires agencies to consider all "important aspect[s] of the problem" and articulate a rational connection between the facts and the choice made.[32] Both case law and executive guidance interpreting this requirement counsel strongly in favor of considering internationally-connected climate costs in administrative rulemaking.

With regard to case law, as noted above, two courts of appeals have already applied arbitrary and capricious review to support the use of a global social cost of carbon in setting regulatory standards. In *Center for Biological Diversity v. NHTSA*, the U.S. Court of Appeals for the Ninth Circuit not only held that it was arbitrary not to monetize the greenhouse gas benefits of vehicle efficiency standards, but also approvingly cited a partial consensus among experts around an estimate of "$50 per ton of carbon (or $13.60 per ton CO2),"[33] which, in the year 2006 when the rule was issued, would have been consistent with estimates of a global social cost of carbon.[34] More recently, in *Zero Zone v. Department of Energy*, the Court of Appeals for the Seventh Circuit found, in response to petitioners' challenge that the agency's consideration of the global social cost of carbon was arbitrary, that the agency had acted reasonably in considering the global climate effects.[35]

Since at least 2010, including some recent agency actions under the Trump administration,[36] federal agencies have based their regulatory decision and NEPA reviews on global estimates of the social cost of greenhouse gases. Though agencies often also disclosed a "highly speculative" range that tried to capture exclusively U.S. climate costs, emphasis on a global value has been recognized as more accurate given the science and economics of climate change, as more consistent with best economic practices, and as crucial to advancing U.S. strategic goals.[37]

Opponents of climate regulation have long challenged the global number in court and other forums, and often attempted to use Circular A-4 as support.[38] Specifically, opponents have seized on Circular A-4's instructions to "focus" on effects to "citizens and residents of the United States," while any significant effects occurring "beyond the borders of the United States . . . should be reported separately."[39] Importantly, despite this language and such challenges, the U.S. Court of Appeals for the Seventh Circuit had no trouble concluding that a global focus for the social cost of greenhouse gases was reasonable:

[The industry petitioners] next contend that [the Department of Energy] arbitrarily considered the global benefits to the environment but only considered the national costs. They emphasize that the [statute] only concerns "national energy and water conservation." In the New Standards Rule, DOE did not let this submission go unanswered. It explained that climate change "involves a global externality," meaning that carbon released in the United States affects the climate of the entire world. According to DOE, national energy conservation has global effects, and, therefore, those global effects are an appropriate consideration when looking at a national policy. Further, AHRI and Zero Zone point to no global costs that should have been considered alongside these benefits. Therefore, DOE acted reasonably when it compared global benefits to national costs.[40]

Circular A-4's reference to effects "beyond the borders" confirms that it is appropriate for agencies to consider the global effects of U.S. greenhouse gas emissions. While Circular A-4 may suggest that most typical decisions should focus on U.S. effects, the Circular cautions agencies that special cases call for different emphases:

[Y]ou cannot conduct a good regulatory analysis according to a formula. Conducting high-quality analysis requires competent professional judgment. ***Different regulations may call for different emphases*** in the analysis, ***depending on the nature and complexity*** of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions.[41]

In fact, Circular A-4 elsewhere assumes that agencies' analyses will not always be conducted from purely the perspective of the United States, as one of its instructions only applies "as long as the analysis is conducted from the United States perspective,"[42] suggesting that in some circumstances it is appropriate for the analysis to be global. For example, EPA and the Department of Transportation have adopted a global perspective on the analysis of potential monopsony benefits to U.S. consumers resulting from the reduced price of foreign oil imports following energy efficiency increases.[43]

Perhaps more than any other issue, a consideration of climate change requires precisely such a "different emphasis" from the default domestic-only assumption. To avoid a global "tragedy of the commons" that could irreparably damage all countries, including the United States, every nation should ideally set policy according to the global social cost of greenhouse gases.[44] Climate and clean air are global common resources, meaning they are freely available to all countries, but any one country's use—i.e., pollution— imposes harms on the polluting country as well as the rest of the world. Because greenhouse gas pollution does not stay within geographic borders but rather mixes in the atmosphere and affects climate worldwide, each ton emitted by the United States not only creates domestic harms, but also imposes large externalities on the rest of the world. Conversely, each ton of greenhouse gases abated in another country benefits the United States along with the rest of the world.

If all countries set their greenhouse emission levels based on only domestic costs and benefits, ignoring the large global externalities, the aggregate result would be substantially sub-optimal climate protections and significantly increased risks of severe harms to all nations, including the United States. Thus, basic economic principles demonstrate that the United States stands to benefit greatly if all countries apply global social cost of greenhouse gas values in their regulatory decisions and project reviews. Indeed, the United States stands to gain hundreds of billions or even trillions of dollars in direct benefits from efficient foreign action on climate change.[45]

In order to ensure that other nations continue to use global social cost of greenhouse gas values, it is important that the United States itself continue to do so.[46] The United States is engaged in a repeated strategic dynamic with several significant players—including the United Kingdom, Germany, Sweden, and others—that have already adopted a global framework for valuing the social cost of greenhouse gases.[47] For example, Canada and Mexico have explicitly borrowed the U.S. estimates of a global social cost of carbon to set their own fuel efficiency standards.[48] For the United States to now depart from this collaborative dynamic by reverting to a domestic-only estimate would undermine the country's long-term interests and could jeopardize emissions reductions underway in other countries, which are already benefiting the United States.

For these and other reasons, reliance on a domestic-only valuation is inappropriate. In the past, some agencies have, in addition to the global estimate, also disclosed a "highly speculative" estimate of the domestic-only effects of climate change. In particular, the Department of Energy always includes a chapter on a domestic-only value of carbon emissions in the economic analyses supporting its energy efficiency standards; EPA has also often disclosed similar estimates.[49] Such an approach is consistent with Circular A-4's suggestion that agencies should usually disclose domestic effects separately from global effects. However, as we have discussed, reliance on a domestic-only methodology would be inconsistent with both the inherent nature of climate change and the standards of Circular A-4. Consequently, under Circular A-4, EPA should have estimated, and used in its primary analysis, the global social cost of carbon.

For more details on the justification for a global value of the social cost of greenhouse gases, including the applicable standards of rational decision making, please see Peter Howard & Jason Schwartz, *Think Global: International Reciprocity as Justification for a Global Social Cost of Carbon*, 42 Columbia J. Envtl. L. 203 (2017), attached. Another strong defense of the global valuation as consistent with best economic practices appears in a letter published in *The Review of Environmental Economics and Policy*, co-authored by Nobel laureate Kenneth Arrow. As Arrow and his co-authors explained: "To solve the unprecedented global commons problem posed by climate change, all nations must internalize the global externalities of their emissions[.] . . . [O]therwise, collective abatement efforts will never achieve an efficient, stable climate outcome."[50]

Benefits and Costs that "Accrue to Citizens and Residents of the United States" Extend Far Beyond U.S. Borders

To follow Circular A-4's instruction to analyze all significant effects that "accrue to [U.S.] citizens," agencies must look beyond "the borders of the United States" to a much broader range of climate effects. For one, because of our world's interconnected financial, political, health, security, and environmental systems, climate impacts occurring initially beyond the geographic borders of the United States cause significant costs that accrue to U.S. citizens and residents. Second, because U.S. climate policy impacts the climate policies of other nations, deregulatory actions such as this proposal have an indirect effect on foreign emissions and thus cause climate-related domestic impacts that are not accounted for in EPA's estimates. And third, U.S. citizens have direct interests in climate-related impacts that will occur overseas, including those affecting citizens living abroad or harming international habitats or species that U.S. citizens value. EPA makes no effort to address this reality, rather saying the agency follows the guidance of Circular A-4 "by adopting a domestic perspective in [its] central analysis."[51] Below, we detail each of these three important aspects of climate damages for which the EPA's "domestic-only" valuation fails to account.

International Spillovers: First, EPA's valuation of the social cost of carbon ignores significant, indirect costs to trade, human health, and security likely to "spill over" to the United States as other regions experience climate change damages.[52] Due to its unique place among countries—both as the largest economy with trade- and investment-dependent links throughout the world, and as a military superpower—the United States is particularly vulnerable to effects that will spill over from other regions of the world. Spillover scenarios could entail a variety of serious costs to the United States as unchecked climate change devastates other countries. Correspondingly, mitigation or adaptation efforts that avoid climate damages to foreign countries will radiate benefits back to the United States as well.[53] While the current integrated assessment models ("IAMs") provide reliable but conservative estimates of global damages, they currently cannot calculate reliable region-specific estimates, in part because they do not model such spillovers.

As climate change disrupts the economies of other countries, decreased availability of imported inputs, intermediary goods, and consumption goods may cause supply shocks to the U.S. economy. Shocks to the supply of energy, technological, and agricultural goods could be especially damaging. For example, when Thailand—the world's second-largest producer of hard-drives—experienced flooding in 2011, U.S. consumers faced higher prices for many electronic goods, from computers to cameras.[54] A recent economic study explored how heat stress-induced reductions in productivity worldwide will ripple through the interconnected global supply network.[55] Similarly, the U.S. economy could experience demand shocks as climate-affected countries decrease their demand for U.S. goods. Financial markets may also suffer as foreign countries become less able to loan money to the United States and as the value of U.S. firms declines with shrinking foreign profits. As seen historically, economic disruptions in one country can cause financial crises that reverberate globally at a breakneck pace.[56]

The human dimension of climate spillovers includes migration and health effects. Water and food scarcity, flooding or extreme weather events, violent conflicts, economic collapses, and a number of other climate damages could precipitate mass migration to the United States from regions worldwide, especially, perhaps, from Latin America. For example, a 10% decline in crop yields could trigger the emigration of 2% of the entire Mexican population to other regions, mostly to the United States.[57] Such an influx could strain the U.S. economy and will likely lead to increased U.S. expenditures on migration prevention. Infectious disease could also spill across the U.S. borders, exacerbated by ecological collapses, the breakdown of public infrastructure in poorer nations, declining resources available for prevention, shifting habitats for disease vectors, and mass migration.

Finally, climate change is predicted to exacerbate existing security threats—and possibly catalyze new security threats—to the United States.[58] Besides threats to U.S. military installations and operations at home and abroad from flooding, storms, extreme heat, and wildfires,[59] climate change is also a "source[] of conflict around the world" requiring U.S. response, according to a Department of Defense report issued earlier this year.[60] This report corroborates a 2014 Department of Defense report declaring that climate effects "are threat multipliers that will aggravate stressors abroad such as poverty, environmental degradation, political instability, and social tensions—conditions that can enable terrorist activity and other forms of violence," and as a result "climate change may increase the frequency, scale, and complexity of future missions, including defense support to civil authorities, while at the same time undermining the capacity of our domestic installations to support training activities."[61] As an example of the climate-security-migration nexus, prolonged drought in Syria likely exacerbated the social and political tensions that erupted into an ongoing civil war,[62] which has triggered an international migration and humanitarian crisis.[63]

Because of these interconnections, attempts to artificially segregate a U.S.-only portion of climate damages will inevitably result in misleading underestimates. Some experts on the social cost of carbon have concluded that, given that integrated assessment models currently do not capture many of these key inter-regional costs, use of the global social cost of greenhouse gas estimates may be further justified as a proxy to capturing all spillover effects.[64] Though not all climate damages will spill back to affect the United States, many will, and together with other justifications, the likelihood of significant spillovers makes a global valuation the better, more transparent accounting of the full range of costs and benefits that matter to U.S. policymakers and the public.

EPA even recognizes in its regulatory impact analysis that the failure to "model all relevant regional interactions—e.g., how climate change impacts in other regions of the world could affect the United States, through pathways such as global migration, economic destabilization, and political destabilization"—represents a major challenge to estimating a domestic-only social cost of carbon.[65] EPA also notes that the National Academies of Sciences concluded that it "is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States."[66] Yet after acknowledging the serious deficiencies in its own domesticonly estimate, EPA fails to address these shortcomings and account for spillovers in any meaningful way. EPA therefore arbitrarily ignores an important factor.

Reciprocal Foreign Actions: Second, an indirect consequence of the United States using a global social cost of greenhouse gas to justify actions that protect against climate damages is that foreign countries take reciprocal actions that benefit the United States. Yet EPA arbitrarily fails to account for this likely significant impact. Circular A-4 requires that the "same standards of information and analysis quality that apply to direct benefits and costs should be applied to ancillary benefits and countervailing risks."[67] Consequently, any attempt to estimate a domestic-only value of the social cost of greenhouse gas must include indirect effects from reciprocal foreign actions.

As detailed more in Howard & Schwartz (2017), because the world's climate is a single interconnected system, the United States benefits greatly when foreign countries consider the global externalities of their greenhouse gas pollution and cut emissions accordingly. Game theory predicts that one viable strategy for the United States to encourage other countries to think globally in setting their climate policies is for the United States to do the same, in a tit-for-tat, lead-by-example, or coalition-building dynamic. In fact, most other countries with climate policies already use a global social cost of carbon or set their carbon taxes or allowances at prices above their domestic-only costs, consistent with the global perspective used to date by U.S. agencies to value the cost of greenhouse gases. Both Republican and Democratic administrations have recognized that the analytical and regulatory choices of U.S. agencies can affect the actions of foreign countries, which in turn affect U.S. citizens.[68] This impact can be incredibly significant: According to one study, by 2030, direct U.S. benefits from global climate policies already in effect could reach over $2 trillion.[69] Any attempt to estimate a domestic-only value of the social cost of greenhouse gases must include such indirect effects from reciprocal foreign actions.[70]

EPA again recognizes this shortcoming in its own domestic-only value, noting that the National Academies of Sciences recommended that a "thorough[] estimati[on]" of the social cost of carbon "consider the potential implications of climate impacts on, and actions by, other countries, which also have impacts on the United States."[71] Once again, however, EPA fails to address this serious deficiency and account for reciprocity in any meaningful way. EPA therefore arbitrarily ignores another important cost of carbon emissions resulting from the proposed deregulation.

Extraterritorial Interests: Circular A-4 requires agencies to count all significant costs and benefits, and specifically explains the importance of including "non-use" values like "bequest and existence values". Yet by "ignoring these values" in calculating the social cost of carbon, contrary to Circular A-4's explicit instructions, EPA "significantly understate[s] the … costs" of the proposed deregulation.[72] Similarly, Circular A-4 recognizes that U.S. citizens may have "altruism for the health and welfare of others," and instructs agencies that when "there is evidence of selective altruism, it needs to be considered specifically in both benefits and costs."[73] Many costs and benefits accrue to U.S. citizens from use values, non-use values, and altruism attached to climate effects occurring outside the U.S. borders, and EPA's valuation of the social cost of carbon fails to account for these significant effects.

A domestic-only estimate based on some rigid conception of geographic borders or U.S. share of world GDP will fail to capture all the climate-related costs and benefits that matter to U.S. citizens,[74] including significant U.S. ownership interests in foreign businesses, properties, and other assets, as well as consumption abroad including tourism,[75] and even the 8.7 million Americans living abroad.[76] Notably, EPA admits that its estimates of cost savings from the proposed deregulation do not distinguish between foreign and domestic ownership of affected firms, and so "some of the cost savings accruing to entities outside U.S. borders is captured in the compliance cost" calculated by EPA.[77] EPA never attempts, nor should it, to separate out cost effects to foreign interests and relegate such effects to an appendix; yet EPA arbitrarily treats U.S. financial interests in global forgone climate benefits differently.

The United States also has a willingness to pay—as well as a legal obligation—to protect the global commons of the oceans and Antarctica from climate damages. For example, the Madrid Protocol on Environmental Protection to the Antarctic Treaty commits the United States and other parties to the "comprehensive protection of the Antarctic environment," including "regular and effective monitoring" of "effects of activities carried on both within and outside the Antarctic Treaty area on the Antarctic environment."[78] The share of climate damages for which the United States is responsible is not limited to our geographic borders.

Similarly, U.S. citizens value natural resources and plant and animal lives abroad, even if they never use those resources or see those plants or animals. For example, the "existence value" of restoring the Prince William Sound after the 1989 Exxon Valdez oil tanker disaster—that is, the benefits derived by Americans who would never visit Alaska but nevertheless felt strongly about preserving the existence of this pristine environment—was estimated in the billions of dollars.[79] Though the methodologies for calculating existence value remain controversial,[80] U.S. citizens certainly have a non-zero willingness to pay to protect rainforests, charismatic megafauna like pandas, and other life and environments existing in foreign countries. U.S. citizens also have an altruistic willingness to pay to protect foreign citizens' health and welfare.[81] This altruism is "selective altruism," consistent with Circular A-4, because the United States is directly responsible for a huge amount of the historic emissions contributing to climate change.[82]

No Current Methodology for Estimating a "Domestic-Only" Value Is Consistent with Practices for Reasoned Decision making

OMB, the National Academies of Sciences, and the economic literature all agree that existing methodologies for calculating a "domestic-only" value of the social cost of greenhouse gases are deeply flawed and result in severe and misleading underestimates.

In developing the social cost of carbon, the IWG did offer some such domestic estimates. Using the results of one economic model (FUND) as well as the U.S. share of global gross domestic product ("GDP"), the group generated an "approximate, provisional, and ***highly speculative***" range of 7–23% of the global social cost of carbon as an estimate of the purely direct climate effects to the United States.[83] Yet, as the IWG itself acknowledged, this range is almost certainly an underestimate because it ignores significant, indirect costs to trade, human health, and security that are likely to spill over into the United States as other regions experience climate change damages, among other effects.[84]

Neither the existing IAMs nor a share of global GDP are an appropriate basis for calculating a domestic-only estimate. The IAMs were never designed to calculate a domestic SCC, since a global SCC is the economically efficient value. FUND, like other IAMS, includes some simplifying assumptions: of relevance, FUND and the other IAMs are not able to capture the adverse effects that the impacts of climate change in other countries will have on the United States through trade linkages, national security, migration, and other forces.[85] This is why the IWG characterized the domestic-only estimate from FUND as a "highly speculative" underestimate. Similarly, a domestic-only estimate based on some rigid conception of geographic borders or U.S. share of world GDP will fail to capture all the climate-related costs and benefits that matter to U.S. citizens.[86] U.S. citizens have economic and other interests abroad that are not fully reflected in the U.S. share of global GDP. GDP is a "monetary value of final goods and services—that is, those that are bought by the final user—produced in a country in a given period of time."[87] GDP therefore does not reflect significant U.S. ownership interests in foreign businesses, properties, and other assets, as well as consumption abroad including tourism,88 or even the 8 million Americans living abroad.[89]

At the same time, GDP is also over-inclusive, counting productive operations in the United States that are owned by foreigners. Gross National Income ("GNI"), by contrast, defines its scope not by location but by ownership interests.[90] However, not only has GNI fallen out of favor as a metric used in international economic policy,[91] but using a domestic-only SCC based on GNI would make the SCC metrics incommensurable with other costs in regulatory impact analyses, since most regulatory costs are calculated by U.S. agencies regardless of whether they fall to U.S.-owned entities or to foreign-owned entities operating in the United States.[92] Furthermore, both GDP and GNI are dependent on what happens in other countries, due to trade and the international flow of capital. The artificial constraints of both metrics counsel against a rigid split based on either U.S. GDP or U.S. GNI.[93]

As a result, in 2015, OMB concluded, along with several other agencies, that "good methodologies for estimating domestic damages do not currently exist."[94] Similarly, the NAS recently concluded that current IAMs cannot accurately estimate the domestic social cost of greenhouse gases, and that estimates based on U.S. share of global GDP would be likewise insufficient.[95] William Nordhaus, the developer of the DICE model, cautioned earlier this year that "regional damage estimates are both incomplete and poorly understood," and "there is little agreement on the distribution of the SCC by region."[96] In short, any domestic-only estimate will be inaccurate, misleading, and out of step with the best available economic literature, in violation of Circular A-4's standards for information quality.

EPA Relies on Sources that Cannot Accurately Calculate a Domestic-Only Estimate and that Explicitly Caution Against Using Domestic-Only Estimates

Despite broad consensus that there are no existing methodologies that accurately project domestic climate damages, EPA attempts to derive a domestic estimate anyway using existing international damage estimates. Specifically, EPA reports that its domestic-only estimates are "calculated directly" from the models FUND and PAGE; for the model DICE, EPA simply assumes that U.S. damages are 10% of global damages.[97] EPA thus uses these models in ways they were never designed for—indeed, in ways their designers specifically cautioned against. EPA furthermore fails to assess the most up-to-date literature on U.S. damages and fails to take steps to reflect spillover effects, reciprocal benefits, or U.S. interests beyond our borders. EPA's methodology is deeply flawed.

The integrated assessment models used by the agency to calculate the social cost of carbon were designed to create global estimates and are best suited for those purposes. The models are limited in how accurately and fully they can estimate domestic values of the social cost of carbon. For example, the models make simplifying assumptions about the extent of heterogeneity in crucial parameters like relative prices and discount rates.[98] The models also simplify or ignore completely global spillovers from trade, migration, and other sources.[99] These types of spillovers will not, in many cases, affect the global estimate of climate change damages, but they will change (perhaps dramatically so) the domestic estimates, as detailed below. For example, trade effects will net to zero globally. A decrease in exports by one country must correspond to a decrease in imports for another country.[100] Global estimates will also generally be more accurate than domestic estimates because aggregation of multiple values reduces the error of the overall estimate.[101]

An examination of the individual models used by the agency to calculate the domestic social cost of carbon—PAGE 2009, FUND 3.8, and DICE 2010[102]—highlights the current limitations to calculating of a domestic value of the social cost of greenhouse gases. For example, the only way that the PAGE model "calculate[s] directly" regional impacts is through its "regional scaling factors," which are "based on the length of each region's coastline relative to the [European Union]. Because of the long coastline in the EU, other regions are, on average, [deemed to be] less vulnerable than the EU for the same sea level and temperature increase."[103] In other words, PAGE calculates climate impacts occurring within U.S. borders by first estimating the climate damages that an additional ton of carbon will cause in Europe, and then scaling down that value because the United States has a coastline that is three times shorter than Europe's.[104]

While relative coastline length may provide a reasonable scaling factor for certain climate damages, such as from coastal flooding, coastal storms, and other sea-level rise issues, it likely understates many other key climate damages—perhaps dramatically so—to the United States, where increases in mortality, agricultural losses, and other important climate effects will also occur in inland, warm areas of the country,[105] and will occur regardless of relative coastline length. Accordingly, EPA's methodology for calculating domestic climate damages from the PAGE model—one of just three models that the agency incorporates—completely disregards significant damage categories. When Congress instructed EPA to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population," it surely did not intend for EPA to limit its assessment of all U.S. interests and public welfare based on the length of our coastline, ignoring massive climate and public-health costs not directly related to coastal flooding. Yet, in relying on PAGE's approach to calculating regional impacts, that is precisely what EPA has done.

The other two models on which EPA based its domestic estimates similarly overlook substantial damage categories. The FUND model generally estimates domestic damages from climate change by scaling estimates according to gross domestic product or population. For instance, forestry damages are "mapped to the FUND regions assuming that the impact is uniform [relative] to GDP."[106] Similarly, domestic energy consumption changes are a function of gross domestic product, and the authors note that "heating demand is linear in the number of people" in a FUND region.[107] Scaling damages by gross domestic product and population will fail to capture important differences between countries like pre-existing climate, interconnectedness of trade relationships, climate change preparedness, and preferences.

These issues are readily apparent in the case of agricultural damage estimates in FUND. Agriculture is one of the most important sectors driving the relatively low damages in the FUND model. Yet, recent evidence on this sector that incorporates cutting-edge estimates of crop yield changes finds that the FUND model substantially understates the agricultural damages from climate change.[108] Particularly for domestic damages, new research shows that FUND dramatically understates the effect of warming on agricultural outcomes globally and for individual countries like the United States.[109] These higher damage estimates come from updates to the relationship between warming and crop yield but also from a more thorough modeling of international trade in agricultural products.

Finally, the author of DICE 2010 has explicitly warned against using a domestic-only value. In a recent article, William Nordhaus states, "The regional estimates [of the social cost of greenhouse gases] are poorly understood, often varying by a factor of 2 across the three models. Moreover, regional damage estimates are highly correlated with output shares." He later reiterates that "the regional damage estimates are both incomplete and poorly understood."[110] These statements reinforce the conclusion of OMB that "good methodologies for estimating domestic damages do not currently exist."[111] EPA's inaccurate and arbitrary methodological shortcuts in estimating a domestic-only social cost of carbon are exemplified by the application of a 10% domestic share to the DICE results.

In conclusion, EPA's estimation of the domestic-only social cost of carbon ignores "important aspect[s] of the problem" and fails to articulate a rational connection between the data and the choice made, and is therefore arbitrary and capricious in violation of the Administrative Procedure Act.[112]

EPA Inconsistently Counts in Full the Portion of Cost that Will Accrue to Foreign Owners and Customers, While Ignoring Benefits from Global Climate Impacts

In addition to its failure to account for significant domestic costs, EPA also treats costs and benefits inconsistently by counting considerable benefits that will accrue to foreign residents from the proposed deregulation. While we do not endorse EPA's benefits estimates, the agency has unlawfully "put a thumb on the scale" by counting certain purported foreign benefits while ignoring foreign costs.[113]

EPA admits that some portion of the proposed action's costs savings will "accru[e] to entities outside U.S. borders."[114] EPA tries to downplay these effects to foreign entities by qualifying its admission "to the extent that affected firms have some foreign ownership."[115] EPA never attempts to separate out cost effects to foreign interests or to relegate such effects to an appendix. Yet a significant portion of cost savings will ultimately accrue to foreign owners and foreign customers of U.S. firms. Consequently, EPA's choice to ignore U.S. financial interests in global climate benefits is a starkly arbitrary and inconsistent treatment of costs and benefits.

A significant portion of the proposed action's cost savings will accrue to foreign entities. All industry compliance costs ultimately fall on the owners, employees, and customers of regulated and affected firms. At a minimum, many if not all regulated and affected firms that are public companies have significant foreign ownership of stock and corporate debt. For example, Southern Company—a major utility that has been active in the development of the proposed deregulation[116]—is a public company. Based on its recent 13F filings and an assessment of its top 100 institutional shareholders, upwards of 15% of Southern Company stock is held by foreign governments (such as the pension plans of the governments of Canada, South Korea, Sweden, and Norway; the Central Bank of Switzerland; and Her Majesty the Queen in Right of the Province of Alberta) or by foreign-based investment banks or funds (like Sumitomo Mitsui Trust Holdings Inc. of Japan and the Commonwealth Bank of Australia).[117] Norway's Government Pension Fund held over $300 million worth of Southern Company stock as of 2018.[118] Of course, many of those foreign-based investment banks and funds will have U.S. investors, but U.S.-based funds that invest heavily in Southern Company, like BlackRock, will similarly have foreign investors. Economy-wide, between 20-30% of U.S. stocks and 35% of U.S. corporate debt are held by foreigners,[119] with significant foreign direct investment in U.S. mining and fossil fuel extraction, in U.S. utilities, and in U.S. manufacturing.[120] A significant portion of the regulatory effects passing through Southern Company and other publicly-traded regulated companies would ultimately be experienced by such foreign owners.

EPA has arbitrarily drawn different geographic lines around which costs and benefits it chooses to consider. EPA should consider all significant global harms for a global pollutant like greenhouse gases, instead of inconsistently treating the costs and benefits that accrue to foreign versus domestic entities.

31 BCA at 8-6.

32 5 U.S.C. § 706; *see Motor Vehicle Manufacturers Assoc. v. State Farm Mutual Auto. Ins. Co*., 463 U.S. 29, 41-42 (1983) (applying the standards of review to deregulatory action and concluding that when "rescinding a rule" an agency "is obligated to supply a reasoned analysis for the change beyond that which may be required when an agency does not act in the first instance").

33 538 F.3d at 1199, 1201.

34 *See* Average Fuel Economy Standards, Passenger Cars and Light Trucks; Model Years 2011-2015, 73 Fed. Reg. 24,352, 24,414 (May 2, 2008) (the National Highway Traffic Safety Administration estimated that $14 per ton of carbon dioxide approximated global benefits).

35 832 F.3d at 679.

36 *See, e.g.*, Dep't of Energy, Energy Conservation Program: Energy Conservation Standards for Walk-In Cooler and Freezer Refrigeration Systems, 82 Fed. Reg. 31,808, 31,812 (July 10, 2017) ("DOE maintains that consideration of global benefits is appropriate because of the global nature of the climate change problem."); U.S. Dep't of Interior, Bureau of Ocean Energy Mgmt., Draft Envtl. Impact Statement: Liberty Development Project at 3-129, 4-246 (Aug. 2017) (BOEM, Liberty Development Project), *available at* https://cdxnodengn.epa.gov/cdx-enepa-II/public/action/eis/details?eisId= 236901 (calling the global social cost of carbon estimates developed in 2016 by the Interagency Working Group "a useful measure" and applying them to analyze the consequences of offshore oil and gas drilling); Dep't of Energy, Energy Conservation Program: Energy Conservation Standards for Air Compressors, 85 Fed. Reg. 1504, 1508 (Jan. 10, 2020) ("DOE maintain that consideration of global benefits is appropriate because of the global nature of the climate change problem."); *id.* at 1566 ("Following the recommendation of the IWG, DOE places more focus on a global measure of SC-CO2. The climate change problem is highly unusual in at least two respects. First, it involves a global externality: Emissions of most greenhouse gases contribute to damages around the world even when they are emitted in the United States. Consequently, to address the global nature of the problem, the SC-CO2 must incorporate the full (global) damages caused by GHG emissions. Second, climate change presents a problem that the United States alone cannot solve. Even if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change. Other countries would also need to take action to reduce emissions if significant changes in the global climate are to be avoided. Emphasizing the need for a global solution to a global problem, the United States has been actively involved in seeking international agreements to reduce emissions and in encouraging other nations, including emerging major economies, to take significant steps to reduce emissions. When these considerations are taken as a whole, the interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable. DOE's approach is not in contradiction of the requirement to weigh the need for national energy conservation, as one of the main reasons for national energy conservation is to contribute to efforts to mitigate the effects of global climate change.").

37 *See generally* Howard & Schwartz, *supra* note 30.

38 Ted Gayer & W. Kip Viscusi, *Determining the Proper Scope of Climate Change Policy Benefits in U.S. Regulatory Analyses: Domestic versus Global Approaches*, 10 REV. ENVTL. ECON. & POL'Y 245 (2016) (citing Circular A-4 to argue against a global perspective on the social cost of carbon); *see also, e.g.*, Petitioners Brief on Procedural and Record-Based Issues at 70, in *West Virginia v. EPA*, case 15-1363, D.C. Cir. (filed February 19, 2016) (challenging EPA's use of the global social cost of carbon).

39 Circular A-4 at 15; *see also* RIA at 3-9, 3-14 (quoting Circular A-4 at 15). Note that Circular A-4 slightly conflates "accrue to citizens" with "borders of the United States": U.S. citizens have financial and other interests tied to effects beyond the borders of the United States, as discussed further below.

40 *Zero Zone*, 832 F.3d at 679.

41 Circular A-4 at 3.

42 *Id.* at 38 (counting international transfers as costs and benefits "as long as the analysis is conducted from the United States perspective").

43 *See* Howard & Schwartz, *supra* note 30, at 268-69.

44 *See* Garrett Hardin, *The Tragedy of the Commons*, 162 Science 1243 (1968) ("[E]ach pursuing [only its] own best interest . . . in a commons brings ruin to all.").

45 Policy Integrity, *Foreign Action, Domestic Windfall: The U.S. Economy Stands to Gain Trillions from Foreign Climate Action* (2015), http://policyintegrity.org/files/publications/ForeignActionDomesticWindfall.pdf

46 *See* Robert Axelrod, *The Evolution of Cooperation* 10-11 (1984) (on repeated prisoner's dilemma games).
47 *See* Howard & Schwartz, *supra* note 30, at Appendix B.
48 *See* Heavy-Duty Vehicle and Engine Greenhouse Gas Emission Regulations, SOR/2013-24, 147 Can. Gazette pt. II, 450, 544 (Can.), *available at* http://canadagazette.gc.ca/rp-pr/p2/2013/2013-03-13/html/sor-dors24-eng.html ("The values used by Environment Canada are based on the extensive work of the U.S. Interagency Working Group on the Social Cost of Carbon."); Jason Furman & Brian Deese, *The Economic Benefits of a 50 Percent Target for Clean Energy Generation by 2025*, White House Blog, June 29, 2016 (summarizing the North American Leader's Summit announcement that U.S., Canada, and Mexico would "align" their SCC estimates).
49 Howard & Schwartz, *supra* note 30, at 220-21.
50 Richard Revesz, Kenneth Arrow et al., *The Social Cost of Carbon: A Global Imperative*, 11 REVIEW OF ENVTL. ECON. & POLICY 172 (2017).
51 BCA at 8-6.
52 Indeed, the integrated assessment models used to develop the global SCC estimates largely ignore inter-regional costs entirely. *See* Peter Howard, *Omitted Damages: What's Missing from the Social Cost of Carbon* (Cost of Carbon Project Report, 2014). Though some positive spillover effects are also possible, such as technology spillovers that reduce the cost of mitigation or adaptation, *see* S. Rao et al., *Importance of Technological Change and Spillovers in Long-Term Climate Policy*, 27 ENERGY J. 123-39 (2006), overall spillovers likely mean that the U.S. share of the global SCC is underestimated, *see* Jody Freeman & Andrew Guzman, *Climate Change and U.S. Interests*, 109 COLUMBIA L. REV. 1531 (2009).
53 *See* Freeman & Guzman, *supra* note 52, at 1563-93.
54 *See* Charles Arthur, *Thailand's Devastating Floods Are Hitting PC Hard Drive Supplies*, THE GUARDIAN (Oct. 25, 2011).
55 Leonie Wenz & Anders Levermann, *Enhanced Economic Connectivity to Foster Heat Stress-Related Losses*, SCIENCE ADVANCES (June 10, 2016).
56 *See* Steven L. Schwarcz, *Systemic Risk*, 97 GEO. L.J. 193, 249 (2008) (observing that financial collapse in one country is inevitably felt beyond that country's borders).
57 Shuaizhang Feng, Alan B. Krueger & Michael Oppenheimer, *Linkages Among Climate Change, Crop Yields and Mexico-U.S. Cross-Border Migration*, 107 PROC. NAT'L ACAD. SCI. 14,257 (2010).
58 *See* CNA Military Advisory Board, *National Security and the Accelerating Risks of Climate Change* (2014).
59 U.S. Gov't Accountability Office, GAO-14-446 *Climate Change Adaptation: DOD Can Improve Infrastructure Planning and Processes to Better Account for Potential Impacts* (2014); Union of Concerned Scientists, *The U.S. Military on the Front Lines of Rising Seas* (2016).
60 U.S. Dep't of Defense, Report on Effects of a Changing Climate to the Dep't of Defense 8 (Jan. 2019), *available at* https://media.defense.gov/2019/Jan/29/2002084200/-1/-1/1/CLIMATE-CHANGE-REPORT-2019.PDF. Recently-departed Secretary of Defense James Mattis has also explained that "[c]limate change is impacting stability in areas of the world where our troops are operating today." Andrew Revkin, *Trump's Defense Secretary Cites Climate Change as National Security Challenge*, ProPublica, Mar. 14, 2017.
61 U.S. Dep't of Defense, *Quadrennial Defense Review 2014* vi, 8 (2014).; see also U.S. Dep't of Defense, *Report to Congress: National Security Implications of Climate-Related Risks and a Changing Climate* (2015), *available at* http://archive.defense.gov/pubs/150724-congressional-report-on-national-implications-of-climatechange. pdf?source=govdelivery ("Global climate change will have wide-ranging implications for U.S. national security interests over the foreseeable future because it will aggravate existing problems—such as poverty, social tensions, environmental degradation, ineffectual leadership, and weak political institutions—that threaten domestic stability in a number of countries.")
62 *See* Center for American Progress et al., *The Arab Spring and Climate Change: A Climate and Security Correlations Series* (2013); Colin P. Kelley et al., *Climate Change in the Fertile Crescent and Implications of the Recent Syrian Drought*, 112 PROC. NAT'L ACAD. SCI. 3241 (2014); Peter H.

Gleick, *Water, Drought, Climate Change, and Conflict in Syria*, 6 WEATHER, CLIMATE & SOCIETY, 331 (2014).
63 *See, e.g.*, *Ending Syria War Key to Migrant Crisis, Says U.S. General*, BBC.COM (Sept. 14, 2015).
64 *See* Robert E. Kopp & Bryan K. Mignone, Circumspection, Reciprocity, and Optimal Carbon Prices, 120 CLIMATE CHANGE 831, 833 (2013).
65 BCA at 8-8.
66 *Id.* (internal quotation marks omitted).
67 Circular A-4 at 26.
68 Howard & Schwartz, *supra* note 30, at 232-37 (citing acknowledgement of this phenomenon by both the Bush administration and the Obama administration).
69 Policy Integrity, *Foreign Action, Domestic Windfall: The U.S. Economy Stands to Gain Trillions from Foreign Climate Action* 11 (2015), http://policyintegrity.org/files/publications/ForeignActionDomesticWindfall.pdf.
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71 BCA at 8-8.
72 Circular A-4 at 22.
73 *Id.*
74 A domestic-only SCC would fail to "provide to the public and to OMB a careful and transparent analysis of the anticipated consequences of economically significant regulatory actions." Office of Information and Regulatory Affairs, *Regulatory Impact Analysis: A Primer* 2 (2011).
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77 BCA at 8-8.
78 Madrid Protocol on Environmental Protection to the Antarctic Treaty (1991), http://www.ats.aq/documents/recatt/Att006_e.pdf
79 RICHARD REVESZ & MICHAEL LIVERMORE, RETAKING RATIONALITY 121 (2008).
80 *Id.* at 129.
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91 *Id*.
92 U.S. Office of Management and Budget & Secretariat General of the European Commission, *Review of Application of EU and US Regulatory Impact Assessment Guidelines on the Analysis of Impacts on International Trade and Development* 13 (2008).
93 Advanced Notice of Proposed Rulemaking on Regulating Greenhouse Gas Emissions Under the Clean Air Act, 73 Fed. Reg. 44,354, 44,415 (July 30, 2008) ("Furthermore, international effects of climate change may also affect domestic benefits directly and indirectly to the extent U.S. citizens value international impacts (e.g., for tourism reasons, concerns for the existence of ecosystems, and/or concern for others); U.S. international interests are affected (e.g., risks to U.S. national security, or the U.S. economy from potential disruptions in other nations).").
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96 William Nordhaus, *Revisiting the Social Cost of Carbon*, 114 PNAS 1518, 1522 (2017).
97 BCA at I-1.
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99 *See generally* Howard & Schwartz, *supra* note 30.
100 *See, e.g.* PAUL R. KRUGMAN, MAURICE OBSTFELD & MARC J. MELITZ, INTERNATIONAL ECONOMICS: THEORY AND POLICY (10 ed. 2015). Such changes could have an effect on overall levels of trade, in turn effecting global damage estimates.
101 *See, e.g.* SIDNEY I RESNICK, A PROBABILITY PATH (2013) at 203.
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113 *Ctr. for Biological Diversity*, 538 F.3d at 1198.
114 BCA at 8-8.
115 *Id.*
116 *See e.g.*, EPA-HQ-OW-2009-0819-8275 (including a June 5, 2018 e-mail from Richard Benware, EPA's Steam Electric ELG Team Leader, reporting "a long meeting with Southern Company").
117 *See, e.g.,* NASDAQ, *Southern Company Institutional Ownership*, http://www.nasdaq.com/symbol/so/institutionalholdings? page=2 (last visited Apr. 26, 2018) (listing holdings by the Commonwealth Bank of Australia, Norges Bank, Siwss National Bank, UBS Asset Management, and Sumitomo Mitsui Trust Holdings).
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Comment Excerpt:

C. EPA Must Rely on a 3% or Lower Discount Rate for Intergenerational Effects—or a Declining Discount Rate

Because of the long lifespan of greenhouse gases and the long-term or irreversible consequences of climate change, the effects of today's emissions changes will stretch out over the next several centuries. The time horizon for an agency's analysis of climate effects, as well as the discount rate applied to future costs and benefits, determines how an agency treats future generations. Traditionally, federal agencies have focused on a central estimate of the social cost of greenhouse gases calculated at a 3% discount rate. EPA now proposes to give equal consideration to estimates calculated at a 7% discount rate, alleging that this is recommended by Circular A-4.[121] EPA is wrong.

Not only does use of a 7% discount rate violate EPA's statutorily required consideration of impacts on future generations, but a 7% rate for intergenerational climate effects is inconsistent with best economic practices, including under Circular A-4. In 2015, OMB explained that "Circular A-4 is a living document. . . . [T]he use of ***7 percent is <u>not</u> considered appropriate*** for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself. "[122] While Circular A-4 tells agencies generally to use a 7% discount rate in addition to lower rates for typical rules,[123] the guidance does not intend for default assumptions to produce analyses inconsistent with best economic practices. Circular A-4 clearly supports using lower rates to the exclusion of a 7% rate for the costs and benefits occurring over the extremely long, 300-year time horizon of climate effects.

A 7% Discount Rate Is Not "Sound and Defensible" or "Appropriate" for Climate Effects

Circular A-4 clearly requires agency analysts to do more than rigidly apply default assumptions: "You cannot conduct a good regulatory analysis according to a formula. Conducting high-quality analysis requires competent professional judgment."[124] As such, analysis must be "based on the best reasonably obtainable scientific, technical, and economic information available,"[125] and agencies must "*[u]se sound and defensible values* or procedures to monetize benefits and costs, and ensure that key analytical assumptions are defensible."[126] Rather than assume a 7% discount rate should be applied automatically to every analysis, Circular A-4 requires agencies to justify the choice of discount rates for each analysis: "[S]tate in your report what assumptions were used, *such as . . . the discount rates* applied to future benefits and costs," and explain "clearly how you arrived at your estimates."[127] Based on Circular A-4's criteria, there are numerous reasons why applying a 7% discount rate to climate effects that occur over a 300-year time horizon would be unjustifiable.

First, basing the discount rate on the **consumption rate of interest** is the correct framework for analysis of climate effects; a discount rate based on the private return to capital is inappropriate. Circular A-4 does suggest that 7% should be a "default position" that reflects regulations that primarily displace capital investments; however, the Circular explains that "[w]hen regulation primarily and directly affects private consumption . . . *a lower discount rate is appropriate*."[128] The 7% discount rate is based on a private sector rate of return on capital, but private market participants typically have short time horizons. By contrast, climate change concerns the public well-being broadly. Rather than evaluating an optimal outcome from the narrow perspective of investors alone, economic theory requires analysts to make the optimal choices based on societal preferences and social discount rates. Moreover, because climate change is expected to largely affect large-scale consumption, as opposed to capital investment,[129] a 7% rate is inappropriate.

In 2013, OMB called for public comments on the social cost of greenhouse gases. In its 2015 Response to Comment document,[130] OMB (together with the other agencies from the IWG) explained that

[T]he consumption rate of interest is the correct concept to use . . . as the impacts of climate change are measured in consumption-equivalent units in the three IAMs used to estimate the SCC. This is consistent with OMB guidance in Circular A-4, which states that when a regulation is expected to primarily affect private consumption—for instance, via higher prices for goods and services—it is appropriate to use the consumption rate of interest to reflect how private individuals trade-off current and future consumption.[131]

The Council of Economic Advisers similarly interprets Circular A-4 as requiring agencies to choose the appropriate discount rate based on the nature of the regulation: "[I]n Circular A-4 by the Office of Management and Budget (OMB) the appropriate discount rate to use in evaluating the net costs or benefits of a regulation depends on whether the regulation primarily and directly affects private consumption or private capital."[132] The NAS also explained that a consumption rate of interest is the appropriate basis for a discount rate for climate effects.[133] There is also strong consensus through the economic literature that a capital discount rate like 7% is inappropriate for climate change.[134] Finally, each of the three integrated assessment models upon which EPA bases its analysis—DICE, FUND, and PAGE—uses consumption discount rates; a capital discount rate is thus inconsistent with the underlying models. (See the technical appendix on discounting attached to these comments for more details.) For these reasons, 7% is an inappropriate choice of discount rate for the impacts of climate change.

Second, **uncertainty over the long time horizon** of climate effects should drive analysts to select a lower discount rate. As an example of when a 7% discount rate is appropriate, Circular A-4 identifies an EPA rule with a 30-year timeframe of costs and benefits.[135] By contrast, greenhouse gas emissions generate effects stretching out across 300 years. As Circular A-4 notes, "[p]rivate market rates provide a reliable reference for determining how society values time within a generation, but for extremely long time periods no comparable private rates exist."[136]

Circular A-4 discusses how uncertainty over long time horizons drives the discount rate lower: "the longer the horizon for the analysis," the greater the "uncertainty about the appropriate value of the discount rate," which supports a lower rate.[137] Circular A-4 cites the work of renowned economist Martin Weitzman and concludes that the "certainty-equivalent discount factor . . . corresponds to ***the minimum discount rate having any substantial positive probability***."[138] The National Academies of Sciences makes the same point about discount rates and uncertainty.[139] In fact, as discussed more below and in the technical appendix on discounting, uncertainty over the discount rate is best addressed by adopting a declining discount rate framework.

Third, a 7% discount rate **ignores catastrophic risks and the welfare of future generations**. As demonstrated in EPA's graph of the frequency distribution of social cost of carbon estimates, the 7% rate truncates the long right-hand tail of social costs relative to the 3% rate's distribution.[140] The long righthand tail represents the possibility of catastrophic damages. The 7% discount rate effectively assumes that present-day Americans are barely willing to pay anything at all to prevent medium- to long-term catastrophes. This assumption violates EPA's statutory duty to protect the future needs of Americans. At the same time, the 7% distribution also misleadingly exaggerates the possibility of negative estimates of the social cost of greenhouse gases.[141] A negative social cost of carbon implies a discount rate so high that society is willing to sacrifice serious impacts to future generations for the sake of small, short-term benefits (such as slightly and temporarily improved fertilization for agriculture). Again, this assumption is inconsistent with empirical data and contravenes EPA's statutory responsibilities to protect the welfare of future Americans.

Fourth, a 7% discount rate would be inappropriate for climate change because it is based on **outdated data and diverges from the current economic consensus**. Circular A-4 requires that assumptions— including discount rate choices—are "based on the best reasonably obtainable scientific, technical, and economic information available."[142] Yet Circular A-4's own default assumption of a 7% discount rate was published 16 years ago and was based on data from decades ago.[143] Circular A-4's guidance on discount rates is in need of an update, as the Council of Economic Advisers detailed recently after reviewing the best available economic data and theory:

The discount rate guidance for Federal policies and projects was last revised in 2003. Since then a general reduction in interest rates along with a reduction in the forecast of long-run interest rates, warrants serious consideration for a reduction in the discount rates used for benefit-cost analysis.[144]

In addition to recommending a value below 7% as the discount rate based on private capital returns, the Council of Economic Advisers further explains that, because long-term interest rates have fallen, a discount rate based on the consumption rate of interest "should be at most 2 percent,"[145] which further confirms that applying a 7% rate to a context like climate change would be wildly out of step with the latest data and theory. Similarly, recent expert elicitations—a technique supported by Circular A-4 for filling in gaps in knowledge[146]—indicate that a growing consensus among experts in climate economics for a discount rate between 2% and 3%; 5% represents the upper range of values recommended by experts, and few to no experts support discount rates greater than 5% being applied to the costs and benefits of climate change.[147] Based on current economic data and theory, the most appropriate discount rate for climate change is 3% or lower.

Fifth, Circular A-4 requires more than giving all possible assumptions and scenarios equal attention in a sensitivity analysis; if alternate assumptions would fundamentally change the decision, Circular A-4 requires analysts to select the **most appropriate assumptions from the sensitivity analysis**.

Circular A-4 indicates that significant intergenerational effects will warrant a special sensitivity analysis focused on discount rates even lower than 3%:

Special ethical considerations arise when comparing benefits and costs across generations. . . It may not be appropriate for society to demonstrate a similar preference when deciding between the well-being of current and future generations. . . If your rule will have important intergenerational benefits or costs you might consider a further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefits using discount rates of 3 and 7 percent.[148]

Elsewhere in Circular A-4, OMB clarifies that sensitivity analysis should not result in a rigid application of all available assumptions regardless of plausibility. Circular A-4 instructs agencies to depart from default assumptions when special issues "call for different emphases" depending on "the sensitivity of the benefit and cost estimates to the key assumptions."[149] More specifically:

If benefit or cost estimates depend heavily on certain assumptions, you should make those assumptions explicit and carry out *sensitivity analyses using plausible alternative assumptions*. If the value of net benefits changes from positive to negative (or vice versa) or if the relative ranking of regulatory options changes with alternative plausible assumptions, you should conduct further analysis to determine ***which of the alternative assumptions is more appropriate***.[150]

In other words, if using a 7% discount rate would fundamentally change the agency's decision compared to using a 3% or lower discount rate, the agency must evaluate which assumption is most appropriate. Since OMB, the Council of Economic Advisers, the National Academies of Sciences, and the economic literature all conclude that a 7% rate is inappropriate for climate change, agencies should select a 3% or lower rate. EPA's selection of a 7% discount rate cannot be justified as "based on the best reasonably obtainable scientific, technical, and economic information available" and so is inconsistent with best practices for cost-benefit analysis under Circular A-4.[151]

Buried in an appendix, EPA does conduct a sensitivity analysis using a 2.5% discount rate.[152] The massive forgone climate benefits estimated at the 2.5% discount rate[153] suggest that some of EPA's net benefit calculations could change from positive to negative depending on the choice of discount rate, especially if combined with a switch from a domestic-only to a global perspective. As Circular A-4 instructs, when a sensitivity analysis results in net benefits switching from positive to negative, the agency must conduct more analysis to justify why its assumptions—including the choice of discount rate—are appropriate. As argued in these comments, further analysis will confirm that a 7% discount rate assumption is not appropriate, and that EPA instead must focus its regulatory analysis and justification on a 3%, 2.5%, or declining discount rate framework.

Application of a Declining Discount Rate Is Actionable Under the Current Economic Literature

Circular A-4 contemplates the use of declining discount rates in its reference to the work of Weitzman.[154] As the Council of Economic Advisers explained earlier this year, Weitzman and others developed the foundation for a declining discount rate approach, wherein rates start relatively higher for near-term costs and benefits but steadily decline over time according to a predetermined schedule until, in the very long-term,very low rates dominate due to uncertainty.[155] The National Academies of Sciences' report also strongly endorses a declining discount rate approach.[156]

One possible schedule of declining discount rates was proposed by Weitzman.[157] It is derived from a broad survey of top economists and other climate experts and explicitly incorporates arguments around interest rate uncertainty. Work by Arrow *et al*, Cropper *et al*, and Gollier and Weitzman, among others, similarly argue for a declining interest rate schedule and lay out the fundamental logic.[158] Another schedule of declining discount rates has been adopted by the United Kingdom.[159]

The technical appendix on discounting attached to these comments more thoroughly reviews the various schedules of declining discount rates available for agencies to select and explains why agencies not only can, but should adopt a declining discount framework to address uncertainty.

A 300-Year Time Horizon Is Required

Related to the choice of discount rate, a 300-year time horizon for analysis of climate effects is required by best economic practices. In 2017, the National Academies of Sciences issued a report stressing the importance of a longer time horizon for calculating the social cost of greenhouse gases, finding that "[i]n the context of the socioeconomic, damage, and discounting assumptions, the time horizon needs to be long enough to capture the vast majority of the present value of damages."[160] The report goes on to note that the length of the time horizon is dependent "on the rate at which undiscounted damages grow over time and on the rate at which they are discounted. Longer time horizons allow for representation and evaluation of longer-run geophysical system dynamics, such as sea level change and the carbon cycle."[161] In other words, after selecting the appropriate discount rate based on theory and data (in this case, 3% or below), analysts should determine the time horizon necessary to capture all costs and benefits that will have important net present values at the discount rate. Therefore, a 3% or lower discount rate for climate change implies the need for a 300-year horizon to capture all significant values. The National Academies of Science reviewed the best available, peer-reviewed scientific literature and concluded that the effects of greenhouse gas emissions over a 300-year period are sufficiently well established and reliable as to merit consideration in estimates of the social cost of greenhouse gases.[162]

121 BCA at I-1 ("Future damages are discounted using constant discount rates of both 3 and 7 percent, as recommended by OMB Circular A-4.").

122 OMB 2015 Response to Comments, *supra* note 108, at 36 (emphasis added).

123 Circular A-4 at 36 ("For regulatory analysis, you should provide estimates of net benefits using both 3 percent and 7 percent….If your rule will have important intergenerational benefits or costs you might consider a further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefits using discount rates of 3 and 7 percent.").

124 Circular A-4 at 3.

125 *Id.* at 17.

126 *Id.* at 27 (emphasis added).

127 *Id.* at 3.

128 *Id.* at 33.

129 Maureen Cropper, *How Should Benefits and Costs Be Discounted in an Intergenerational Context?*, 183 RESOURCES 30, 33 (2013) ("There are two rationales for discounting future benefits—one based on consumption and the other on investment. The consumption rate of discount reflects the rate at which society is willing to trade consumption in the future for consumption today. Basically, we discount the consumption of future generations because we assume future generations will be wealthier than we are and that the utility people receive from consumption declines as their level of consumption increases. . . . The investment approach says that, as long as the rate of return to investment is positive, we need to invest less than a dollar today to obtain a dollar of benefits in the future. Under the investment approach, the discount rate is the rate of return on investment. If there were no distortions or inefficiencies in markets, the consumption rate of discount would equal the rate of return on investment. There are, however, many reasons why the two may differ. As a result, using a consumption rather than investment approach will often lead to very different discount rates."); *see also* Richard G. Newell & William A. Pizer, Uncertain Discount Rates in Climate Policy Analysis, 32 ENERGY POL'Y 519, 521 (2004) ("Because climate policy decisions ultimately concern the future welfare of people—not firms—the consumption interest rate is more appropriate.").

130 Note that this document was not withdrawn by Executive Order 13,783.

131 OMB 2015 Response to Comments, *supra* note 108, at 22.

132 Council of Econ. Advisers, *Discounting for Public Policy: Theory and Recent Evidence on the Merits of Updating the Discount Rate* at 1 [hereinafter "CEA Issue Brief"], *available at* https://obamawhitehouse.archives.gov/sites/default/files/ page/files/201701_cea_discounting_issue_brief.pdf. In

theory, the two rates would be the same, but "given distortions in the economy from taxation, imperfect capital markets, externalities, and other sources, the SRTP and the marginal product of capital need not coincide, and analysts face a choice between the appropriate opportunity cost of a project and the appropriate discount rate for its benefits." *Id.* at 9. The correct discount rate for climate change is the social return to capital (i.e., returns minus the costs of externalities), not the private return to capital (which measures solely the returns).

133 NAS Second Report, *supra* note 109, at 28; *see also* Kenneth Arrow et al., Is There a Role for Benefit-Cost Analysis in Environmental, Health, and Safety Regulation?, 272 SCIENCE 221 (1996) (explaining that a consumption-based discount rate is appropriate for climate change).

134 In addition to the CEA and NAS reports, see, for example, this article by the former chair of the NAS panel on the social cost of greenhouse gases: Richard Newell (2017, October 10). Unpacking the Administration's Revised Social Cost of Carbon. Available at http://www.rff.org/blog/2017/unpacking-administration-s-revised-social-cost-carbon. *See also* Comments from Robert Pindyck, to BLM, on the Social Cost of Methane in the Proposed Suspension of the Waste Prevention Rule (submitted Nov. 5, 2017).

135 Circular A-4 at 34. See also OMB 2015 Response to Comments, *supra* note 108, at 21 (noting that "most regulatory impact analysis is conducted over a time frame in the range of 20 to 50 years," and thus do not fully implicate "special ethical considerations [that] arise when comparing benefits and costs across generations").

136 Circular A-4 at 36.

137 *Id.*

138 *Id.*; *see also* CEA Issue Brief, *supra* note 160, at 9: "Weitzman (1998, 2001) showed theoretically and Newell and Pizer (2003) and Groom et al. (2007) confirm empirically that discount rate uncertainty can have a large effect on net present values. A main result from these studies is that if there is a persistent element to the uncertainty in the discount rate (e.g., the rate follows a random walk), then it will result in an effective (or certainty-equivalent) discount rate that declines over time. Consequently, lower discount rates tend to dominate over the very long term, regardless of whether the estimated investment effects are predominantly measured in private capital or consumption terms (see Weitzman 1998, 2001; Newell and Pizer 2003; Groom et al. 2005, 2007; Gollier 2008; Summers and Zeckhauser 2008; and Gollier and Weitzman 2010)."

139 NAS Second Report, *supra* note 109, at 27.

140 BCA at I-4, Figure I-1: Frequency Distribution of Interim Domestic SC-CO2 Estimates for 2030.

141 In the Monte Carlo simulation data, the 7% discount rate doubles the frequency of negative estimates compared to the 3% discount rate simulations, from a frequency of 4% to 8%.

142 Circular A-4 at 17.

143 The 7% rate was based on a 1992 report; the 3% rate was based on data from the 30 years preceding the publication of Circular A-4 in 2003. *Id.* at 33–34.

144 CEA Issue Brief, *supra* note 160, at 1; *see also id.* at 3 ("In general the evidence supports lowering these discount rates, with a plausible best guess based on the available information being that the lower discount rate should be at most 2 percent while the upper discount rate should also likely be reduced."); *id.* at 6 ("The Congressional Budget Office, the Blue Chip consensus forecasts, and the Administration forecasts all place the ten year treasury yield at less than 4 percent in the future, while at the same time forecasting CPI inflation of 2.3 or 2.4 percent per year. The implied real ten year Treasury yield is thus below 2 percent in all these forecasts.").

145 *Id.* at 1.

146 Circular A-4 at 41.

147 Peter Howard & Derek Sylvan, *The Economic Climate: Establishing Expert Consensus on the Economics of Climate Change,* INST. POLICY INTEGRITY WORKING PAPER 33–34 (2015) [hereinafter "Expert Consensus"]; M.A. Drupp, et al., *Discounting Disentangled: An Expert Survey on the Determinants of the Long-Term Social Discount Rate* (London School of Economics and Political Science Working Paper, May 2015) (finding consensus on social discount rates between 1-3%). Pindyck, in a survey of 534 experts on climate change, finds a mean discount rate of 2.9% in the climate change context and this rate drops to 2.6% when he omits individuals that lack confidence in their knowledge. Pindyck, R. S. (2016). *The social cost of carbon revisited* (No. w22807). National Bureau of Economic Research. Unlike Howard and Sylvan (2015), Pindyck (2016) combines economists and natural scientists in his survey, though the mean constant discount rate drops to 2.7% when including only economists. Again, this further supports the finding that the appropriate discount rate is between 2% and 3%.

148 Circular A-4 at 35-36.
149 *Id.* at 3.
150 *Id.* at 42 (emphasis added).
151 *Id.* at 17.
152 BCA at I-4.
153 *See id.* at I-6 (calculating a global estimate at a 2.5% discount rate).
154 Circular A-4, at page 36, cites to Weitzman's chapter in Portney & Weyant, eds. (1999); that chapter, at page 29, recommends a declining discount rate approach: "a sliding-scale social discounting strategy" with the rate at 3-4% through year 25; then around 2% until year 75; then around 1% until year 300; and then 0% after year 300.
155 CEA Issue Brief, *supra* note 160, at 9 ("[A]nother way to incorporate uncertainty when discounting the benefits and costs of policies and projects that accrue in the far future—applying discount rates that decline over time. This approach uses a higher discount rate initially, but then applies a graduated schedule of lower discount rates further out in time. The first argument is based on the application of the Ramsey framework in a stochastic setting (Gollier 2013), and the second is based on Weitzman's 'expected net present value' approach (Weitzman 1998, Gollier and Weitzman 2010). In light of these arguments, the governments of the United Kingdom and France apply declining discount rates to their official public project evaluations.").
156 NAS Second Report, *supra* note 109, at 166.
[157] Martin L. Weitzman, *Gamma Discounting*, 91 AM. ECON. REV. 260, 270 (2001). Weitzman's schedule is as follows:

1-5 years	6-25 years	26-75 years	76-300 years	300+ years
4%	3%	2%	1%	0%

158 Kenneth J. Arrow et al., *Determining Benefits and Costs for Future Generations*, 341 SCIENCE 349 (2013); Kenneth J. Arrow et al., *Should Governments Use a Declining Discount Rate in Project Analysis?*, REV ENVIRON ECON POLICY 8 (2014); Maureen L. Cropper et al., *Declining Discount Rates*, AMERICAN ECONOMIC REVIEW: PAPERS AND PROCEEDINGS (2014); Christian Gollier & Martin L. Weitzman, *How Should the Distant Future Be Discounted When Discount Rates Are Uncertain?* 107 ECONOMICS LETTERS 3 (2010).
[159] Joseph Lowe, H.M. Treasury, U.K., Intergenerational Wealth Transfers and Social Discounting: Supplementary Green Book Guidance 5 (2008), *available at* http://www.hm-treasury.gov.uk/d/4(5).pdf. The U.K. declining discount rate schedule that subtracts out a time preference value is as follows:

0-30 years	31-75 years	76-125 years	126-200 years	201-300 years	301+ years
3.00%	2.57%	2.14%	1.71%	1.29%	0.86%

160 NAS Second Report, *supra* note 109, at 78.
161 *Id.*
162 Nat'l Acad. Of Sci., *Assessment of Approaches to Updating the Social Cost of Carbon* 49 (2016), at 32.

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Comment Excerpt:

B. EPA's Failure to Monetize and Quantify All Costs and Benefits Further Distorts the BCA in Favor of EPA's Preferred Alternative.

EPA's failure to monetize and quantify costs and benefits from significant environmental and human health impacts further distorts the Agency's Proposed BCA. EPA underestimates the human health benefits that could be achieved by reducing or eliminating the pollution loads associated with bottom ash transport water and FGD wastewater. The Agency limits its focus to a narrow subset of health effects, arbitrarily excludes much of the drinking water risk from its analysis, and fails to consider multiple pollutants' potential cumulative impact. EPA likewise failed to monetize significant impacts from anticipated changes in national air emissions rates. As a result, the Proposed BCA seriously distorts any comparison of compliance costs to health and environmental benefits, rendering the BCA meaningless and an arbitrary and invalid basis for any Agency decision-making. Cumulatively, the failure to monetize multiple reduced benefit streams skews the results of EPA's Proposed BCA toward EPA's preferred Option 2 and away from Options offering greater health and environmental protections.[625]

1. EPA omits many health benefits associated with reducing power plant discharges.

EPA's Proposed BCA continues the flawed approach of the 2015 ELG Rule[626] by narrowly focusing on a subset of the health effects associated with a small handful of pollutants. Indeed, EPA acknowledges this fact:

EPA's analysis omits the following health effects: low birth weight and neonatal mortality from in-utero exposure to lead, decreased postnatal growth in children ages one to 16, delayed puberty, immunological effects, decreased hearing and motor function; effects to adults from exposure to lead (e.g., cardiovascular diseases, decreased kidney function, reproductive effects, immunological effects, cancer and nervous system disorders); effects to adults from exposure to mercury, including vision defects, hand-eye coordination, hearing loss, tremors, cerebellar changes, and others; and other cancer and non-cancer effects from exposure to other steam electric pollutants. Therefore, the total monetary value of changes in human health effects included in this analysis represent only a subset of the potential health benefits (or forgone benefits) that are expected to result from the regulatory options.[627]

This is only a partial list of EPA's omissions, which are discussed in more detail below, but even this partial list shows that EPA's Proposed BCA is fatally flawed. Given the dramatically incomplete accounting of health benefits, EPA's comparisons of benefits to costs are meaningless, and cannot be used as a justification for the 2019 Proposal.

Although the Agency analyzes some of the cancer risks associated with bromide byproducts and arsenic, and some of the neurotoxicity associated with exposure to lead and mercury, EPA arbitrarily limits its analysis to a subset of the relevant risks. For arsenic, EPA continues to use an outdated cancer potency estimate, despite knowing that the cancer risks are likely to be 17 times greater than the Proposed BCA assumes. According to EPA's proposed revision to the cancer assessment for arsenic, the best available science supports a cancer potency estimate for oral exposure of 25.7 cases per mg/kg-d, roughly 17 times higher than the potency estimate of 1.5 cases per mg/kg-d used in Proposed BCA.[628] This affects both drinking water risks and fish consumption risks.

For lead, EPA limits its analysis of neurotoxicity to exposure between the ages of 1 and 7, ignoring exposures after age 7 or *in utero*,[629] even though these exposures also convey a risk of neurotoxicity.[630] For mercury, EPA only looks at exposure *in utero*,[631] ignoring exposures after birth, which again convey a risk of neurotoxicity.[632]

It is also important to note that EPA failed to consider cancer risk associated with any pollutant other than bromide byproducts and arsenic, and failed to consider neurotoxicity associated with any pollutant other than lead and mercury, despite the fact that many pollutants in power plant wastewater are known or possible carcinogens and known neurotoxins. These critical omissions are discussed in more detail below.

Beyond cancer and neurotoxicity, the pollutants listed above as well as other toxic pollutants in power plant discharges present a wide range of other health risks. For example, arsenic, boron, lead, and thallium are all associated with reproductive and developmental risks.[633] Cadmium can cause kidney, liver, and lung damage.[634] Hexavalent chromium can harm the liver and blood.[635] Adults exposed to lead have an increased risk of many health effects including hypertension, heart attacks, strokes, and anemia.[636]

[625] See id. at 13-16.
[626] Some of the authors of this comment letter contributed to a critique of the 2015 ELG Rule that bears directly on the current rulemaking. B. Gottlieb et al., Selling Our Health Down the River: Why EPA Needs to Finalize the Strongest Rule to Stop Water Pollution from Power Plants, Docket ID No. EPA-HQ-OW-2009-0819-5555 (June 17, 2015).
[627] Proposed BCA at 2-7 (internal citations omitted); see also 2020 Synapse BCA Analysis at 13-15.
[628] *Compare* EPA, Draft Toxicological Review of Inorganic Arsenic in Support of Summary Information on the Integrated Risk Information System (IRIS), EPA/635/R-10/001 (Feb. 2010) (attached) ("Draft Arsenic Review"), *with* Proposed BCA at 2-7 (citing EPA, Benefit and Cost Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, at 3-16, Docket ID No. EPA-HQ-OW-2009-0819-5856 (Sept. 2015) ("Final 2015 BCA")). Although EPA identified separate potency estimates for women (25.7 cases per mg/kg/d) and men (16.9 cases per mg/kg/d), it stated that the potency estimate for women should be used as the point of departure for the derivation of health criteria. Draft Arsenic Review at 131-32.
[629] Proposed BCA at 5-1, 5-6 to 5-7.
[630] See, e.g., Agency for Toxic Substances & Disease Registry, Toxicological Profile for Lead, at 101-36 (Aug. 2007) (discussing neurological risks after exposure as adults or as children) (attached); J.M. Davis, Risk Assessment of the Developmental Neurotoxicity of Lead, 11 Neurotoxicology 285 (1990) ("Lead has long been recognized as a developmental neurotoxicant.").
[631] Proposed BCA at 5-1, 5-10 to 5-11.
[632] See, e.g., P. Gradjean et al., Neurotoxicity from Prenatal and Postnatal Exposure to Methylmercury, 43 Neurotoxicology and Teratology 39 (2014) ("adverse effects on brain development should be considered a risk associated with postnatal exposures") (attached).
[633] EPA, Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, at 3-4 to 3-10, Docket ID No. EPA-HQ-OW-2009-0819-6427 (Sept. 2015) ("Final 2015 EA"); EPA, Integrated Risk Information System, Lead and Compounds, https://cfpub.epa.gov/ncea/iris/iris_documents/documents/subst/0277_summary.pdf.
[634] Final 2015 EA at 3-4 to 3-10.
[635] California EPA, Public Health Goal for Hexavalent Chromium (Cr VI) in Drinking Water, at 1 (July 2011) (attached).
[636] Final 2015 BCA at 2-4, 3-10.

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Comment Excerpt:

2. EPA's analysis of drinking water impacts is arbitrary, irrational, and incomplete.

EPA acknowledges that there are many pollutants in steam electric discharges whose reduction or elimination could benefit human health.[637] EPA should have evaluated the potential reduction in drinking water concentrations, and the corresponding health benefits, for all of these pollutants. Yet the Agency arbitrarily focused on bromide and its byproducts, total trihalomethanes ("TTHMs"), to the exclusion of almost everything else.[638] Although EPA mentions arsenic and lead, and alludes to the potential health benefit associated with reducing exposure to these pollutants, the Agency ultimately disregards these benefits based on an irrational and inconsistent logic.

As EPA acknowledges, TTHMs, arsenic, and lead share a common characteristic – they are 'non-threshold' pollutants with no safe level of exposure.[639] This means that "any reduction in exposure to these pollutants is expected to yield benefits."[640] Yet EPA fails to account for much of the potential reduction that would come with more stringent pollution controls. The Agency also introduces a substantial inconsistency into its analysis by arbitrarily treating TTHMs one way and treating arsenic and lead the opposite way. At the end of this muddled analysis EPA ends up underestimating the potential benefits of reducing exposure for all three pollutants.

For bromide, EPA only evaluates the health effects associated with reducing TTHM concentrations if those concentrations are already below the Maximum Contaminant Level ("MCL").[641] This ignores any benefit associated with reducing TTHM levels that currently exceed the MCL. If, for example, a drinking water system currently has TTHM concentrations 3 times higher than the MCL, and reducing power plant discharges could bring that concentration down to 1.1 times the MCL, there would be an enormous public health benefit. This is a scenario that EPA ignores entirely. Or consider a situation in which a drinking water system exceeds the TTHM MCL, but only by a small margin, and reducing power plant discharges could bring that concentration down to well below the MCL. Again, EPA apparently ignored this possibility. By ignoring TTHM concentrations above the MCL, EPA has arbitrarily underestimated the health effects of bromide reduction.

EPA's implicit reliance on drinking water utilities' independent obligation to comply with MCLs is misplaced. Although drinking water utilities are required to ensure that water meets MCLs for many individual pollutants, they do not always accomplish this goal. In 2011, for example, there were over 8,000 MCL violations, exposing nearly 15 million people to higher than authorized levels of toxic substances.[642] There is also an indefinite time lag between the moment when a pollutant exceeds an MCL and when the utility re-establishes compliance. This time lag is determined by the amount of time it takes for the exceedance to be noticed, recorded, and reported; the amount of time it takes the relevant regulatory agency to commence an enforcement action; and the amount of time it takes the utility to correct the problem, including any compliance schedule entered into by the utility and the regulatory agency. All of this means that MCL exceedances can expose people to egregiously unsafe levels of TTHMs for long periods of time; this is a risk that EPA must take seriously and analyze.

For arsenic and lead (and other pollutants), EPA's approach is arbitrarily and irrationally the opposite of its approach to bromide. For these pollutants, EPA only considered exposure concentrations that exceed the MCL.[643] This ignores any pollutant reductions between the MCLs for arsenic and lead and their respective MCL goals (zero, in both cases). EPA announces this absurd analytical approach immediately after conceding that "any reduction in exposure to these pollutants is expected to yield benefits."[644] Since any reduction – say, from 90% of the MCL to 10% of the MCL – will yield health benefits, there is simply no justification for EPA to ignore those benefits. This is in fact particularly true for concentrations below the MCL because drinking water utilities will have no legal obligation to reduce those concentrations. The only way to ameliorate this exposure and risk is to reduce pollution loads to source water. In other words, reductions in power plant discharges are guaranteed to have a health benefit, and EPA should analyze that benefit.

A further error in EPA's focus on pollutant levels that exceed MCLs is that EPA has not set MCLs for many of the most health-threatening pollutants in power plant discharges. For example, drinking water utilities are not required to remove manganese, which can cause damage to the developing nervous system, and which power plants discharge at a rate of more than 14 million pounds each year.

By only analyzing bromide byproduct levels <u>below</u> the MCL, while simultaneously limiting its analysis of other pollutants to levels <u>above</u> their MCLs, EPA has created a patently irrational and incomplete patchwork of exposure and risk. EPA must revise its analysis to include all potential pollutant reductions associated with each regulatory option and with a zero discharge regulatory option. This is the only way to capture the true health impacts associated with cleaner drinking water.

[637] See, e.g., Proposed BCA at 2-3 to 2-4, 4-21.
[638] See id. at 4-1 to 4-25.
[639] Id. at 2-4, 4-22.
[640] Id. at 4-22.
[641] Id. at 4-3 ("EPA's analysis quantifies the human health effects associated with incremental changes between the MCL and the [MCL Goal].").
[642] EPA, Fiscal Year 2011 Drinking Water and Ground Water Statistics, EPA-816-R-13-003, at 18-19 (2013) (attached).
[643] Proposed BCA at 4-22.
[644] Id.

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Comment Excerpt:

D. EPA's Estimate for the Social Cost of Carbon Arbitrarily Fails to Follow Prescribed Practices for Dealing with Uncertainty

EPA notes that "limitations" of the IAMs include the "incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts," the models' "incomplete treatment of adaptation," "uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons."[163] That mere mention of significant uncertainty that could lead to much higher social cost of carbon estimates hardly satisfies *Circular A-4*'s requirements for quantitative treatment of uncertainty.[164] The IWG highlighted a 95th percentile estimate to address uncertainty over catastrophic damages, tipping points, option value, and risk aversion.[165] EPA should have done the same, but failed to do so. EPA admits that the distributions "have long right tails"[166] and depicts a range of estimates from the 5th to 95th percentiles,[167] but by giving a 5th percentile estimate equal standing with the 95th percentile estimate, EPA obscures the significance of low-probability, high-catastrophe outcomes. Under sensitivity analyses that treated such low-probability, high-catastrophe outcomes seriously, even with EPA's incorrect choices of discount rate and domestic-only perspective, the sign of net benefits for the proposed deregulation would have shifted from positive to sharply negative. By failing to give serious treatment to such sensitivity analyses, EPA overlooks how different (and more plausible) assumptions would change its cost-benefit calculation.

Uncertainty in general, as well as uncertainty over the discount rate in particular, are discussed in greater detail in the technical appendices attached to these comments.

Circular A-4's Prescriptions for Uncertainty

Circular A-4 requires thorough treatment of uncertainty around both values and outcomes,[168] and for especially large or complex matters it recommends a formal probabilistic analysis.[169] Generally, Circular A-4 encourages agencies to disclose the full probability distribution of potential consequences, including both upper and lower bound estimates in addition to central estimates.[170]

However, this guidance comes with some caveats. First, this approach to central estimates and the probability distribution "is appropriate as long as society is 'risk neutral' with respect to the regulatory alternatives."[171] But if society is risk averse—as is the case with climate change[172]—different considerations need to be considered. Second, in 2011, the Office of Information and Regulatory Affairs interpreted Circular A-4's goal as "not to characterize the full range of *possible* outcomes . . . but rather the range of *plausible* outcomes."[173] Agency analysts must exercise judgment. Finally, as with all elements of agencies' economic analyses, Circular A-4 stresses that regulatory impact analyses "should be credible, objective, realistic, and scientifically balanced."[174]

Consequently, while it may be appropriate to disclose the full probability distribution of an uncertainty analysis, it is not appropriate under Circular A-4 to give a low-percentile estimate of the social cost of greenhouse gases equal weight in decision-making with the central and upper-percentile estimates. Giving equal attention to a low-percentile estimate is not "credible, objective, realistic, and scientifically balanced," does not reflect "plausible" scenarios, and would undermine consideration of risk aversion. Instead, a proper and plausible treatment of uncertainty in the context of climate change will support higher estimates of the social cost of greenhouse gases.

A 95th Percentile Value as a Treatment of Uncertainty over Damages

The IWG accounted for uncertainty in numerous rigorous ways. The group modeled the uncertainty over the value of the equilibrium climate sensitivity parameter using the Roe and Baker distribution calibrated to the IPCC reports. Additionally, using well-established analytic tools to capture and reflect uncertainty, including a Monte Carlo simulation to randomly select the equilibrium climate sensitivity parameter and other uncertainty parameters selected by the model developers, the IWG quantitatively modeled the uncertainty underlying how greenhouse gas emissions affect temperature.

To further deal with uncertainty, the IWG recommended to agencies a range of four estimates: three central or mean-average estimates at a 2.5%, 3%, and 5% discount rate respectively, and a 95th percentile value at the 3% discount rate. While the IWG's technical support documents disclosed fuller probability distributions, these four estimates were chosen by agencies to be the focus for decision making. In particular, application of the 95th percentile value was not part of an effort to show the probability distribution around the 3% discount rate; rather, the 95th percentile value serves as a methodological shortcut to approximate the uncertainties around low-probability but high-damage, catastrophic, or irreversible outcomes that are currently omitted or undercounted in the economic models.

The shape of the distribution of climate risks and damages includes a long tail of lower-probability, high-damage, irreversible outcomes due to "tipping points" in planetary systems, inter-sectoral interactions, and other deep uncertainties. Climate damages are not normally distributed around a central estimate, but rather feature a significant right skew toward catastrophic outcomes. In fact, a 2015 survey of economic experts concludes that catastrophic outcomes are increasingly likely to occur.[175] Because the three integrated assessment models that the IWG's methodology relied on are unable to systematically account for these potential catastrophic outcomes, a 95th percentile value was selected instead to account for such uncertainty. There are no similarly systematic biases pointing in the other direction which might warrant giving weight to a low-percentile estimate.

Additionally, the 95th percentile value addresses the strong possibility of widespread risk aversion with respect to climate change. The integrated assessment models do not reflect that individuals likely have a higher willingness to pay to reduce low-probability, high-impact damages than they do to reduce the likelihood of higher-probability but lower impact damages with the same expected cost. Beyond individual members of society, governments also have reasons to exercise some degree of risk aversion to irreversible outcomes like climate change.

In short, the 95th percentile estimate attempts to capture risk aversion and uncertainties around lower-probability, high-damage, irreversible outcomes that are currently omitted or undercounted by the models. There is no need to balance out this estimate with a low-percentile value, because the reverse assumptions are not reasonable:

- There is no reason to believe the public or the government will be systematically risk seeking with respect to climate change.[176]
- The consequences of overestimating the risk of climate damages (i.e., spending more than we need to on mitigation and adaptation) are not nearly as irreversible as the consequences of underestimating the risk of climate damage (i.e., failing to prevent catastrophic outcomes).
- Though some uncertainties might point in the direction of lower social cost of greenhouse gas values, such as those related to the development of breakthrough adaptation technologies, the models already account for such uncertainties around adaptation; on balance, most uncertainties strongly point toward higher, not lower, social cost of greenhouse gas estimates.[177]
- There is no empirical basis for any "long tail" of potential benefits that would counteract the potential for extreme harm associated with climate change.

Moreover, even the best existing estimates of the social cost of greenhouse gases are likely underestimated because the models currently omit many significant categories of damages—such as depressed economic growth, pests, pathogens, erosion, air pollution, fire, dwindling energy supply, health costs, political conflict, and ocean acidification—and because of other methodological choices.[178] There is little to no support among economic experts to give weight to any estimate lower than the 5% discount rate estimate.[179] Rather, even a discount rate at 3% or below likely continues to underestimate the true social cost of greenhouse gases.

The National Academies of Sciences did recommend that the IWG document its full treatment of uncertainty in an appendix and disclose low-probability as well as high-probability estimates of the social cost of greenhouse gases.[180] However, that does not mean it would be appropriate for individual agencies to rely on low-percentile estimates to justify decisions. While disclosing low-percentile estimates as a sensitivity analysis may promote transparency, relying on such an estimate for decision making—in the face of contrary guidance from the best available science and economics on uncertainty and risk—would not be a "credible, objective, realistic, and scientifically balanced" approach to uncertainty.[181]

By giving only a scant graphical presentation of the 95th percentile value, and by misleadingly placing that value on equal footing with a 5th percentile estimate, EPA has failed to address uncertainties over catastrophic outcomes, tipping points, risk aversion, and option value, and so has violated the prescriptions of Circular A-4. The IWG emphasized the 95th percentile (not the 5th percentile) to address this systematic downward bias in the social cost of greenhouse gases. By giving equal weight to the 5th and 95th percentiles, the EPA is ignoring this systematic bias and failing to consider the accepted logic that climate change is likely to bring with it more bad surprises than good surprises.

Uncertainty over Climate Damages Points Toward a Higher Social Cost of Carbon

A technical appendix attached to these comments more fully details how uncertainty on the whole points toward an even higher social cost of carbon. The appendix covers such topics as insufficient modeling of catastrophic outcomes (including unlucky states of the world, deep uncertainty over the probability distributions for specific climate parameters, and tipping points), failure to include a risk premium, exclusion of the real option value of preventing irreversible greenhouse gas emissions, and how the social cost of greenhouse gases would increase with improved modeling of uncertainty.

163 BCA at 8-7.
164 Circular A-4 at 18 ("When benefit and cost estimates are uncertain . . . you should report benefit and cost estimates (including benefits of risk reductions) that reflect the full probability distribution of potential consequences.").
165 Interagency Working Group on the Social Cost of Carbon, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis 4 (2010).
166 BCA at I-3.
167 *Id* at I-4.
168 Circular A-4, at 42, requires probability distributions for "values as well for each of the outcomes"; the social cost of greenhouse gases is a value with a probability distribution.
169 *Id.* at 41.
170 Circular A-4 at 18, 40; *id.* at 45 ("When you provide only upper and lower bounds (in addition to best estimates), you should, if possible, *use the 95 and 5 percent* confidence bounds.").
171 *Id.* at 42.
172 *See* Interagency Working Group on Social Cost of Carbon, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis 11 (2010).
173 Office of Information and Regulatory Affairs, Regulatory Impact Analysis: A Primer 2 (2011). This is best understood as drawing the line at insignificant or scientifically unsupported outcomes. By contrast, the low-probability but catastrophic potential outcomes of climate change are highly significant and the scientific literature demands giving them due attention.
174 Circular A-4 at 39.
175 Expert Consensus, *supra* note 175, at 2 ("Experts believe that there is greater than a 20% likelihood that this same climate scenario would lead to a 'catastrophic' economic impact (defined as a global GDP loss of 25% or more)."). *See also* Robert Pindyck, *The Social Cost of Carbon Revisited* (National Bureau of Economic Research, No. w22807, 2016).
176 As a 2009 survey revealed, the vast majority of economic experts support the idea that "uncertainty associated with the environmental and economic effects of greenhouse gas emissions increases the value of emission controls, assuming some level of risk-aversion." *See* Expert Consensus*, supra* note 175, at 3 (citing 2009 survey).
177 *See* Revesz et al., *Global Warming: Improve Economic Models of Climate Change*, *supra* note 39. R. Tol, *The Social Cost of Carbon*, 3 Annual Rev. Res. Econ. 419 (2011) ("[U]ndesirable surprises seem more likely than desirable surprises. Although it is relatively easy to imagine a disaster scenario for climate change—for example, involving massive sea level rise or monsoon failure that could even lead to mass migration and violent conflict—it is not at all easy to imagine that climate change will be a huge boost to human welfare.").
178 *See* Revesz et al., *Global Warming: Improve Economic Models of Climate Change*, *supra* note 39; Peter Howard, *Omitted Damages: What's Missing from the Social Cost of Carbon* (Cost of Carbon Project Report, 2014); Frances C. Moore & Delavane B. Diaz, *Temperature Impacts on Economic Growth Warrant Stringent Mitigation Policy*, 5 NATURE CLIMATE CHANGE 127 (2015) (demonstrating SCC may be biased downward by more than a factor of six by failing to include the climate's effect on economic growth).
179 The existing estimates based on the 5% discount rate already provides a lower-bound; indeed, if anything the 5% discount rate is already far too conservative as a lower-bound. A recent survey of 365 experts on the economics of climate change found that 90% of experts believe a 3% discount rate or lower is appropriate for climate change; a 5% discount rate falls on the extremely high end of what experts would recommend. Expert Consensus*, supra* note

175, at 21; *see also* Drupp, M.A., et al. *Discounting Disentangled: An Expert Survey on the Determinants of the Long-Term Social Discount Rate* (London School of Economics and Political Science Working Paper, May 2015) (finding consensus on social discount rates between 1-3%). Only 8% of the experts surveyed believe that the central estimate of the social cost of carbon is below $40, and 69% of experts believed the value should be at or above the central estimate of $40. Expert Consensus, *supra* note 175, at 18.
180 Nat'l Acad. Of Sci., *Assessment of Approaches to Updating the Social Cost of Carbon* 49 (2016) ("[T]he IWG could identify a high percentile (e.g., 90th, 95th) and corresponding low percentile (e.g., 10th, 5th) of the SCC frequency distributions on each graph.").
181 Circular A-4 at 39.

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3. *EPA fails to fully account for cancer risks, neurological risks, or the cumulative risks of exposure to multiple carcinogens or neurotoxins.*

Arsenic and TTHMs are not the only carcinogens in power plant wastewater. Hexavalent chromium is another potent carcinogen in power plant wastewater. Studies in humans show that hexavalent chromium in drinking water can cause stomach cancer, and this is consistent with evidence of digestive system cancers in animal studies.[645] EPA recently proposed a designation of "likely to be carcinogenic to humans" for oral exposure,[646] and the California EPA stated that hexavalent chromium is "carcinogenic by the oral route of exposure."[647] Lead and mercury, which are assessed for their neurological risks in EPA's rulemaking, may also cause cancer. Lead is currently categorized by EPA as a "probable" carcinogen, and methyl mercury is categorized as a "possible human carcinogen," based both on animal studies and evidence of damage to genetic material, a first step in cancer formation.[648]

Similarly, lead and mercury are not the only neurotoxins in power plant wastewater. Manganese is another known neurotoxin found in power plant wastewater.[649] There is growing concern in the scientific community over the effects of manganese, specifically in drinking water.[650] The effects of manganese exposure, even at levels that are commonly found in North American groundwater supplies, include reduced IQ and impaired memory and attention.[651] As with many neurotoxins, children are more sensitive than adults.[652] Arsenic, in addition to causing cancer, is also a neurotoxin.[653] As with manganese, there is growing concern over the risks associated with levels commonly found in drinking water. One recent study in Maine, for example, found significant reductions in IQ and other endpoints in children exposed to 5-10 micrograms of arsenic per liter, a level that is below the current safe drinking water standard for arsenic.[654] Another important neurotoxin is aluminum. EPA has stated that "[o]ne of the greatest health concerns regarding [aluminum] is its neurological effects."[655] As with many neurotoxins, the developing fetus and infants are especially vulnerable.[656]

EPA also fails to account for the combined risk of multiple pollutants that share a common mechanism of toxicity, affect the same body organ or system, or result in the same health endpoint. As discussed above, power plants discharge several cancer-causing pollutants and several neurotoxins, with potential cumulative risks for both endpoints. EPA must consider this potential in any credible BCA.

[645] EPA, Draft Toxicological Review of Hexavalent Chromium in Support of Summary Information on the Integrated Risk Information System (IRIS), EPA/635/R-10/004A, at 199-200 (Sept. 2010) (attached).
[646] Id.
[647] California EPA, Public Health Goal for Hexavalent Chromium (Cr VI) in Drinking Water, at 1 (July 2011) (attached).
[648] EPA, Integrated Risk Information System, Methyl Mercury, https://cfpub.epa.gov/ncea/iris/iris_documents/documents/subst/0073_summary.pdf; EPA, Integrated Risk Information System, Lead and Compounds, https://cfpub.epa.gov/ncea/iris/iris_documents/documents/subst/0277_summary.pdf.
[649] See, e.g., Agency for Toxic Substances & Disease Registry, Toxicological Profile for Manganese (2012) (attached); P. Grandjean & P. Landrigan, Neurobehavioural Effects of Developmental Toxicity, 13 Lancet Neurol. 330 (2014) (attached).
[650] See, e.g., K. Ljung & M. Vahter, Time to Re-Evaluate the Guideline Value for Manganese in Drinking Water? 115 Envtl. Health Persp. 1533 (2007) (attached); H.A. Roels et al., Manganese Exposure and Cognitive Deficits: A Growing Concern for Manganese Toxicity, 33(4) Neurotoxicol. 872 (2012) (attached).
[651] See, e.g., Y. Oulhote et al., Neurobehavioral Function in School-Age Children Exposed to Manganese in Drinking Water, 122 Envtl. Health Persp. 1343 (2014) (attached); M. Bouchard et al., Intellectual Impairment in School-Age Children Exposed to Manganese from Drinking Water, 119 Envtl. Health Persp. 138 (2011) (attached).
[652] Agency for Toxic Substances & Disease Registry, Toxicological Profile for Manganese, at 332-33 (Sept. 2012) (attached).
[653] Agency for Toxic Substances & Disease Registry, Toxicological Profile for Arsenic, at 180-83 (Aug. 2007) (attached); P. Grandjean & P. Landrigan, Neurobehavioural Effects of Developmental Toxicity, 13 Lancet Neurol. 330 (2014) (attached).
[654] G. Wasserman et al., A Cross-Sectional Study of Well Water Arsenic and Child IQ in Maine Schoolchildren, 13 Envtl. Health 23-32 (2014) (attached).
[655] EPA, Provisional Peer-Reviewed Toxicity Values for Aluminum, at 6 (2006) (attached).
[656] Id. at 28.

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4. EPA fails to monetize impacts from anticipated changes in air emissions.

Finally, EPA fails to fully assess and monetize impacts from anticipated changes in air emissions. EPA examined changes in air pollution through three mechanisms: (1) changes in auxiliary electricity use by power plant pollution control trains; (2) changes in transportation-related air emissions from trucking of CCR waste, and most significantly (3) changes in the profile of electric generating units due to altered costs of compliance under the proposed regulatory options.[657] In so doing, EPA "quantified, but did not monetize, changes in emissions of PM2.5 precursors NOx and SO2."[658] Because NOx and SO2 emissions are greater under Option 2,[659] this omission likewise distorts the BCA in favor of its preferred regulatory option.[660]

[657] 84 Fed. Reg. at 64,658.
[658] Proposed BCA at 8-5.
[659] 84 Fed. Reg. at 64,659; see also Proposed BCA at 8-3 to 8-4.
[660] See 2020 Synapse BCA Analysis at 15.

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C. A Corrected BCA Would Demonstrate that Regulatory Option 4, with Certain Revisions, Is the Only Option Offering a Justifiable Change in Environmental and Health Benefits.

To accurately assess benefits and costs of the proposed rule, EPA must correct the structural flaws in the BCA analysis structure and fully quantify and monetize the costs and benefits of its proposed action. Specifically, EPA should evaluate the impact of the proposed modifications against two new baselines: (1) a corrected existing rule baseline, modified to reflect costs and benefits resulting from ELG compliance with the 2015 rule (as modified by the 2017 postponement rule) as well as regulatory changes and updates to the profile of electric generating facilities announced between October 2018 and July 2019, and (2) a status quo baseline of current (2019) conditions.[662] EPA should also separately and transparently calculate and state the costs and benefits associated with each component of its preferred action and alternatives, including all technology bases, subcategories, and assumptions concerning use of the Voluntary Incentives Program.[663]

Based on its own analysis, Synapse Energy Economics concludes that Option 4 – as modified to (1) remove the proposed subcategories for high FGD flow plants, low-utilization boilers, and boilers retiring by 2028 and (2) maintain zero-discharge requirements for bottom ash transport water – is the only regulatory compliance option offering an acceptable change in the level of environmental and health benefits relative to the 2015 rule.[664]

In addition, as discussed in Section VI – Zero Discharge FGD, EPA must also consider a regulatory option that not only maintains zero-discharge requirements for bottom ash transport water, but that also (unlike Option 4) requires zero discharge of FGD wastewater based on use of membrane treatment or other technologies. A zero-discharge rule would maximize environmental benefits at little additional cost over the effluent limitations for FGD wastewater that EPA evaluated under Option 4, given that it would be based on use of the same treatment technologies. EPA's failure to consider the costs and benefits of a regulatory option that completely eliminates discharges from both bottom ash transport water and FGD wastewater further undermines the legitimacy of its benefit-cost analysis.

[662] 2020 Synapse BCA Analysis at 8, 12, 21.
[663] Id. at 13, 22.
[664] See id. at iii, 20-22.

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Comment Excerpt Number: 7

Comment Excerpt:

E. EPA Appropriately Gives Equal Weight to the Three Most Peer-Reviewed Models, but Should Use the Updated Models

EPA equally weighted the results of the three most peer-reviewed integrated assessment models in order to balance out the limitations and omissions of any one model.182 In any future applications of the social cost of carbon, EPA should continue to rely on the Interagency Working Group's methodology and use multiple peer-reviewed models. That said, EPA has failed to use the most up-to-date versions of those models, and should use the updated models in future calculations, including in any revised analysis of its proposed suspension.

Agencies Should Continue to Rely on the Interagency Working Group's Methodology and Estimates

In 2016, IWG published updated central estimates for the social cost of greenhouse gases: $50 per ton of carbon dioxide, $1440 per ton of methane, and $18,000 per ton of nitrous oxide (in 2017 dollars for year 2020 emissions).[183] Notwithstanding the recent Executive Order disbanding the IWG, the estimates updated by that group in 2016 are still the best estimates of the lower bound of the social cost of greenhouse gases, reflecting current best practices and best scientific and economic literature. Agencies should continue to use estimates of a similar or higher value[184] in their regulatory analyses and environmental impact statements. In particular, when estimating the social cost of greenhouse gases, agencies should use multiple peer-reviewed models, a global estimate of climate damages, and a 3% or lower discount rate for the central estimate.

Any departure from IWG's most recent estimates would require agencies to engage with the complex integrated assessment models and ensure consistency with the most current scientific and economic literature, which overwhelmingly supports a global estimate based on a 3% or lower discount rate. Indeed, since the IWG's estimates omit important damage categories and so are best treated as a lower bound, if anything the social cost of greenhouse gas values used by agencies should be even higher.

Agencies Must Not Rely on a Single Model, but Must Use Multiple, Peer-Reviewed Models

Circular A-4 requires agencies to use “the best reasonably obtainable scientific, technical, and economic information available. To achieve this, you should rely on peer-reviewed literature, where available.”[185]

Since the IWG first issued the federal social cost of carbon protocol in 2010, this methodology has relied on the three most cited, most peer-reviewed integrated assessment models (IAMs). These three IAMs— called DICE (the Dynamic Integrated Model of Climate and the Economy[186]), FUND (the Climate Framework for Uncertainty, Negotiation, and Distribution[187]), and PAGE (Policy Analysis of the Greenhouse Effect[188])—draw on the best available scientific and economic data to link physical impacts to the economic damages of each marginal ton of greenhouse gas emissions. As noted previously, each model translates emissions into changes in atmospheric greenhouse gas concentrations, atmospheric concentrations into temperature changes, and temperature changes into economic damages, which can then be adjusted according to a discount rate. These three models have been combined with inputs derived from peer-reviewed literature on climate sensitivity, socio-economic and emissions trajectories, and discount rates. The results of the three models have been given equal weight in federal agencies’ estimates and have been run through statistical techniques like Monte Carlo analysis to account for uncertainty.

In a 2017 report, the National Academies of Sciences recommended future improvements to this methodology. Specifically, over the next five years the NAS recommends unbundling the four essential steps in the IAMs into four separate “modules”: a socio-economic and emissions scenario module, a climate change module, an economic damage module, and a discount rate module.[189] Unbundling these four steps into separate modules could allow for easier, more transparent updates to each individual component in order to better reflect the best available science and capture the full range of uncertainty in the literature. These four modules could be built from scratch or drawn from the existing IAMs. Either way, the integrated modular framework envisioned by NAS for the future will require significant time and resource commitments from federal agencies.

In the meantime, the NAS has supported the continued near-term use of the existing social cost of greenhouse gas estimates based on the DICE, FUND, and PAGE models, as used by federal agencies to date.[190] In short, DICE, FUND, and PAGE continue to represent the state-of-the-art models. The Government Accountability Office found in 2014 that the estimates derived from these models and used by federal agencies are consensus-based, rely on peer-reviewed academic literature, disclose relevant limitations, and are designed to incorporate new information via public comments and updated research.[191] In fact, the social cost of greenhouse gas estimates used in federal regulatory proposals and EISs have been subject to over 80 distinct public comment periods.[192] The economics literature confirms that estimates based on these three IAMs remain the best available estimates.[193] In 2016, the U.S. Court of Appeals for the Seventh Circuit held that those estimates are reasonable for agencies to use in cost-benefit analysis.[194] And more recently, the District of Montana rejected an agency’s Environmental Assessment for failure to incorporate the federal social cost of carbon estimates into its cost-benefit analysis of a proposed mine expansion.[195]

Regardless of Executive Order 13,783's withdrawal of the guidance directing federal agencies to rely on IWG's technical support documents to estimate the social cost of greenhouse gases, IWG's choice of DICE, FUND, and PAGE, its use of inputs and assumptions, and its statistical analysis still represent the state-of-the-art approach based on the best available, peer-reviewed literature. This approach satisfies Circular A-4's requirements for information quality and transparency. Therefore, in complying with the Executive Order's instructions to ensure that social cost of greenhouse gas estimates are consistent with Circular A-4, agencies will necessarily have to rely on models like DICE, FUND, and PAGE, to use the same or similar inputs and assumptions as the IWG, and to apply statistical analyses like Monte Carlo.

The unavoidable fact is that DICE, FUND, and PAGE are still the dominant, most peer-reviewed models,[196] and most estimates in the literature continue to rely on those models.[197] Each of these models has been developed over decades of research, and has been subject to rigorous peer review, documented in the published literature. While other models exist, they lack DICE's, FUND's, and PAGE's long history of peer review or exhibit other limitations. For example, the World Bank has created ENVISAGE, which models a more detailed breakdown of market sectors,[198] but unfortunately does not account for non-market impacts and so would omit a large portion of significant climate effects. Models like ENVISAGE are therefore not currently appropriate choices under the criteria of Circular A-4.[199]

An approach based on multiple, peer-reviewed models (like DICE, FUND, and PAGE) is more rigorous and more consistent with Circular A-4 than reliance on a single model or estimate. DICE, FUND, and PAGE each include many of the most significant climate effects, use appropriate discount rates and other assumptions, address uncertainty, are based on peer-reviewed data, and are transparent.[200] However, each IAM also has its own limitations and is sensitive to its own assumptions. No model fully captures all the significant climate effects.[201] By giving weight to multiple models—as the IWG did—agencies can balance out some of these limitations and produce more robust estimates.[202]

Finally, while agencies should be careful not to cherry-pick a single estimate from the literature, it is noteworthy that various estimates in the literature are consistent with the numbers derived from a weighted average of DICE, FUND, and PAGE—namely, with a central estimate of about $40 per ton of carbon dioxide, and a high-percentile estimate of about $120, for year 2015 emissions (in 2016 dollars, at a 3% discount rate). The latest central estimate from DICE's developers is $87 (at a 3% discount rate);[203] from FUND's developers, $12;[204] and from PAGE's developers, $123, with a high-percentile estimate of $332.[205]

In fact, much of the literature suggests that a central estimate of $40 per ton is a very conservative underestimate. A 2015 meta-analysis—which sought out estimates besides just those based on DICE, FUND, and PAGE—found a mean estimate of $83 per ton of carbon dioxide.[206] Various studies relying on expert elicitation[207] from a large body of climate economists and scientists have found mean estimates of $50 per ton of carbon dioxide,[208] $96-$144 per ton of carbon dioxide,[209] and $80-$100 per ton of carbon dioxide.[210] There is a growing consensus in the literature that even the best existing estimates of the social cost of greenhouse gases may severely underestimate the true marginal cost of climate damages.[211] Overall, a central estimate of $40 per ton of carbon dioxide at a 3% discount rate, with a high-percentile estimate of about $120 for year 2015 emissions, is consistent with the best available literature; if anything, the best available literature supports considerably higher estimates.[212]

Similarly, a comparison of international estimates of the social cost of greenhouse gases suggests that a central estimate of $40 per ton of carbon dioxide is a very conservative value. Sweden places the long-term valuation of carbon dioxide at $168 per ton; Germany calculates a "climate cost" of $167 per ton of carbon dioxide in the year 2030; the United Kingdom's "shadow price of carbon" has a central value of $115 by 2030; Norway's social cost of carbon is valued at $104 per ton for year 2030 emissions; and various corporations have adopted internal shadow prices as high as $80 per ton of carbon dioxide.[213]

Indeed, a number of our organizations have previously commented on ways in which the IWG's approach could be improved to more accurately reflect the true social cost of greenhouse gases. For instance, the IWG's values should incorporate a risk premium, which reflects an additional price that society is willing to pay in order to avoid greater uncertainty about the impacts from climate change. In addition, noted Harvard economist Martin Weitzman has observed that the three IAMs used by the IWG assume a relatively smooth upward slope in economic damages even as the global climate crosses critical tipping points.[214]

An improved social cost of greenhouse gases could reflect modified damage functions that better address tipping points. For these reasons, the IWG's estimates are very likely to underrepresent the true impact that greenhouse gas emissions have on society, and we strongly encourage further efforts to make those estimates more robust. Nevertheless, the IWG's approach represents the best and most rigorous effort that the U.S. government has engaged in thus far to realistically estimate the social cost of greenhouse gases. We therefore strongly urge EPA to adopt the IWG's approach for estimating the social cost of carbon, with the understanding that such estimates should be seen as a conservative lower-bound estimate of the true impacts of this pollutant.

EPA Should Use the Most Updated Models

EPA explains it uses DICE 2010, FUND 3.8, and PAGE 2009.[215] However, not only is DICE 2010 not considered to be a major update of the DICE model,[216] but two major updates have occurred more recently: DICE-2013R[217] and DICE-2016R.[218] In using the outdated DICE 2010, EPA has failed to use the "best available science and economics" as required by Executive Order 13,783, and failed to follow the recommendations of the National Academies of Sciences on updating the integrated assessment models.[219] Updating from DICE 2010 to the most recent model would increase the social cost of greenhouse gases and enable a Monte Carlo simulation (as in FUND and PAGE) to better specify uncertainty.[220]

182 BCA at I-2 (noting that EPA's social cost estimates "are equally weighted across models").
183 Interagency Working Group on the Social Cost of Greenhouse Gases, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (2016).
184 *See* Revesz et al., *Global Warming: Improve Economic Models of Climate Change*, *supra* note 39 (explaining that current estimates omit key damage categories and, therefore, are very likely underestimates).
185 OMB, Circular A-4, at 17.

186 William D. Nordhaus, *Estimates of the social cost of carbon: concepts and results from the DICE-2013R model and alternative approaches*, 1 JOURNAL OF THE ASSOCIATION OF ENVIRONMENTAL AND RESOURCE ECONOMISTS 1 (2014).
187 David Anthoff & Richard S.J. Tol, THE CLIMATE FRAMEWORK FOR UNCERTAINTY, NEGOTIATION AND DISTRIBUTION (FUND), TECHNICAL DESCRIPTION, VERSION 3.6 (2012), *available at* http://www.fund-model.org/versions.
188 Chris Hope, *The Marginal Impact of CO2 from PAGE2002: An Integrated Assessment Model Incorporating the IPCC's Five Reasons for Concern*, 6 INTEGRATED ASSESSMENT J. 19 (2006).
189 NAS Second Report, *supra* note 109 (recommending an "integrated modular approach").
190 Specifically, NAS concluded that a near-term update was not necessary or appropriate and the current estimates should continue to be used while future improvements are developed over time. Nat'l Acad. Sci., Eng. & Medicine, *Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update* 1 (2016) [hereinafter "NAS, First Report"].
191 Gov't Accountability Office, *Regulatory Impact Analysis: Development of Social Cost of Carbon Estimates* (2014).
192 Howard & Schwartz, *supra* note 30, at Appendix A.
193 *E.g.*, Richard G. Newell et al., *Carbon Market Lessons and Global Policy Outlook*, 343 SCIENCE 1316 (2014); Bonnie L. Keeler et al., *The Social Costs of Nitrogen*, 2 SCIENCE ADVANCES e1600219 (2016); Revesz et al., *Global Warming: Improve Economic Models of Climate Change*, *supra* note 39.
194 *Zero Zone*, 832 F.3d at 678–79 (finding that the agency "acted reasonably" in using global estimates of the social cost of carbon, and that the estimates chosen were not arbitrary or capricious).
195 *Montana Environmental Information Center*, 2017 WL 3480262, at *12-15, 19.
196 *See* Interagency Working Group on the Social Cost of Carbon, Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis 7 (July 2015) ("DICE, FUND, and PAGE are the most widely used and widely cited models in the economic literature that link physical impacts to economic damages for the purposes of estimating the SCC."), *citing* Nat'l Acad. Sci., Eng. & Medicine, *Hidden Cost of Energy: Unpriced Consequences of Energy Production and Use* (2010) ("the most widely used impact assessment models").
197 R.S. Tol, *The Social Cost of Carbon*, 3 Annual Rev. Res. Econ. 419 (2011); T. Havranek et al., *Selective Reporting and the Social Cost of Carbon*, 51 Energy Econ. 394 (2015).
198 World Bank, *The Environmental Impact and Sustainability Applied General Equilibrium (ENVISAGE) Model* (2008), *available at* http://siteresources.worldbank.org/INTPROSPECTS/Resources/334934-1193838209522/Envisage7b.pdf.
199 Similarly, Intertemporal Computable Equilibrium System (ICES) does not account for non-market impacts. *See* https://www.cmcc.it/models/ices-intertemporal-computable-equilibrium-system. Other models include CRED, which is worthy of further study for future use. Frank Ackerman, Elizabeth A. Stanton & Ramón Bueno, *CRED: A New Model of Climate and Development*, 85 ECOLOGICAL ECONOMICS 166 (2013). Accounting for omitted impacts more generally, E.A. Stanton, F. Ackerman, R. Bueno, *Reason, Empathy, and Fair Play: The Climate Policy Gap*, (Stockholm Environment Inst. Working Paper 2012-02), find a doubling of the SCC using the CRED model.
200 While sensitivity analysis can address parametric uncertainty within a model, using multiple models helps address structural uncertainty.
201 *See* Peter Howard, *Omitted Damages: What's Missing from the Social Cost of Carbon* 5 (Cost of Carbon Project Report, 2014), http://costofcarbon.org/.
202 Frances C. Moore et al., Economic Impacts of Climate Change on Agriculture: a Comparison of Process-Based and Statistical Yield Models, 12 Envtl. Research Letters (2017).
203 William Nordhaus, *Revisiting the Social Cost of Carbon*, Proc. Nat'l Acad. Sci. (2017) (estimate a range of $21 to $141).
204 D. Anthoff & R. Tol, *The Uncertainty about the Social Cost of Carbon: A Decomposition Analysis Using FUND*, 177 Climatic Change 515 (2013).

205 C. Hope, *The social cost of CO2 from the PAGE09 model*, 39 Economics (2011); C. Hope, *Critical issues for the calculation of the social cost of CO2*, 117 *Climatic Change*, 531 (2013).
206 S. Nocera et al., *The Economic Impact of Greenhouse Gas Abatement through a Meta-Analysis: Valuation, Consequences and Implications in terms of Transport Policy*. 37 Transport Policy 31 (2015).
207 Circular A-4, at 41, supports use of expert elicitation as a valuable tool to fill gaps in knowledge.
208 Scott Holladay & Jason Schwartz, *Economists and Climate Change* 43 (Inst. Policy Integrity Brief, 2009 (directly surveying experts about the SCC).
209 Expert Consensus, *supra* note 175 (using survey results to calibrate the DICE-2013R damage function).
210 R. Pindyck, *The Social Cost of Carbon Revisited* (Nat'l Bureau of Econ. Res. No. w22807, 2016) ($80-$100 is the trimmed range of estimates at a 4% discount rate; without trimming of outlier responses, the estimate is $200).
211 *See, e.g., id*.; Expert Consensus*, supra* note 175. The underestimation results from a variety of factors, including omitted and outdated climate impacts (including ignoring impacts to economic growth and tipping points), simplified utility functions (including ignoring relative prices), and applying constant instead of a declining discount rate. *See* Howard, *supra* note 229; Revesz et al., *Global Warming: Improve Economic Models of Climate Change*, *supra* note 39; J.C. Van Den Bergh & W.J. Botzen, A Lower Bound to the Social Cost of CO2 Emissions, 4 Nature Climate Change 253 (2014) (proposing $125 per metric ton of carbon dioxide in 1995 dollars, or about $200 in today's dollars, as the lower bound estimate). *See also* F.C. Moore & D.B. Diaz, *Temperature Impacts on Economic Growth Warrant Stringent Mitigation Policy*, 5 Nature Climate Change 127 (2015) (concluding the SCC may be six times higher after accounting for potential growth impacts of climate change). Accounting for both potential impacts of climate change on economic growth and other omitted impacts, S. Dietz and N. Stern find a two- to seven-fold increase in the SCC. *Endogenous growth, convexity of damage and climate risk: how Nordhaus' framework supports deep cuts in carbon emissions*. 125 *The Economic Journal* 574 (2015).
212 Note that the various estimates cited in the paragraph have not all been converted to standard 2017$, and may not all reflect the same year emissions. Nevertheless, the magnitude of this range suggests that $40 per ton of year 2015 emissions is a conservative estimate.
213 *See* Howard & Schwartz, *supra* note 30, at Appendix B. All these estimates are in 2016$.
214 Martin L Weitzman, *On Modeling and Interpreting the Economics of Catastrophic Climate Change*, 91 REV. ECON. STAT. 1–19 (2009) at 15-18.
215 BCA at I-1.
216 William Nordhaus & Paul Sztorc, DICE 2013R: Introduction and User's Manual (2013), *available at* http://www.econ.yale.edu/~nordhaus/homepage/homepage/documents/DICE_Manual_100413r1.pdf.
217 William Nordhaus, Estimates of the Social Cost of Carbon: Concepts and Results from the DICE-2013R Model and Alternative Approaches, 1 JOURNAL OF THE ASSOCIATION OF ENVIRONMENTAL AND RESOURCE ECONOMISTS 273–312 (2014).
218 William Nordhaus, Revisiting the Social Cost of Carbon, 114 PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES 1518 (2017).
219 NAS Second Report, *supra* note 109. Note that the Interagency Working Group was incorrect in 2016 in failing to update the DICE model from DICE-2010 to DICE-2013R, which was available at the time. *Cf.* IWG, 2013 Technical Update (updating the models). *See also* Marten, A.L., Kopits, E.A., Griffiths, C.W., Newbold, S.C., and A. Wolverton. 2015. Incremental CH4 and N2O Mitigation Benefits Consistent with the U.S. Government's SC-CO2 Estimates. Climate Policy. 15(2): 272-298 (anticipating that the models will be continually updated).
220 The update would also increase EPA's calculation of the domestic-only share from 10% to 15%, *see* Nordhaus, W. D. (2017). Revisiting the social cost of carbon. *Proceedings of the National Academy of Sciences*, 201609244. But, as explained in these comments, a domestic-only value is the wrong framework and is inaccurate.

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Comment Excerpt:

F. EPA Has Cherry-Picked Methodological Revisions to Advance a Predetermined Goal, Without Engaging in a Holistic Update

As detailed above, the EPA's "interim values" for the social cost of carbon were produced from a series of choices that are all methodologically unsound: ignoring the global values and calculating an inaccurate and incomplete domestic-only estimate; applying the inappropriate 7% discount rate; and failing to disclose a 95^{th} percentile estimate. What links these select revisions together is a common, predetermined goal: lowering the social cost of carbon to support deregulation.

This is an arbitrary approach to updating the social cost of carbon. EPA does not engage with any of the most recent literature on damages (see the technical appendix attached to these comments on damage literature), does not update the underlying models (EPA continues to use DICE-2010, even though DICE- 2016R has been published), does not move toward a declining discount rate, and does not implement any of the recommendations for improving the social cost of greenhouse gas methodology as articulated by the National Academies of Sciences. EPA notes, but then does nothing about, the National Academies of Sciences' warning that domestic-only numbers fail to account for "regional interactions."[221] EPA has had almost three years since the National Academies of Sciences' January 2017 report was published to incorporate its recommendations into a proper update of the social cost of greenhouse gases; instead, EPA continues to use the same "interim" estimates, with no indication of any process for properly revising the estimates.[222] Agencies should pursue a holistic update of the social cost of greenhouse gas methodology, but EPA only seems interested in revisions designed to lower the valuation. As such, EPA's interim values are biased and should not be used in analysis.

The National Academies of Sciences' reports are attached to these comments, so that EPA might review their recommendations for a holistic update to the methodology.

221 BCA at 8-8.
222 *Id.* at 8-6 ("These SC-CO2 estimates developed under E.O. 13783 presented below will be used in regulatory analysis until more comprehensive domestic estimates can be developed, which would take into consideration recent recommendations from the National Academies of Sciences, Engineering, and Medicine (2017) to further update the current methodology to ensure that the SC-CO2 estimates reflect the best available science).

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Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 181

Comment Excerpt:

E. EPA Drastically Underestimated the Environmental Impacts of Greenhouse Gas Emissions; a Proper Accounting Supports a Zero-Discharge Rule.

The Social Cost of Carbon ("SCC") is an estimate, in dollars, of the economic damages that would result from emitting one additional ton of greenhouse gases into the atmosphere. The SCC puts the effects of climate change into economic terms to help policymakers and other decisionmakers understand the economic impacts of decisions that would increase or decrease emissions. The SCC was developed based on extensive scientific and economic analysis from several agencies of the government, and included a public review and comment period. The SCC has two important characteristics. First, it accounts for the damage emissions from the United States cause in other countries, because carbon pollution does not remain within the borders of this country. Second, as carbon pollution lasts for centuries in the atmosphere and drives climate change impacts years from now, it gives weight to damages that our emissions will cause to future generations. In 2020 the costs of each ton of carbon pollution are estimated to be roughly \$53/ton.[679] This value still excludes many climate damages, so scientists consider it to be an underestimate of the true cost. Indeed, EPA cites a range of global SCC values of \$55 to \$76 per metric ton.[680]

In 2017, President Trump signed Executive Order 13783, allowing agencies to disregard decades of in-depth and peer-reviewed scientific research and calculate only damages occurring within the United States and employ discount rates that devalue future generations for use in the primary analysis of regulations. For instance, the SCC for domestic economic impacts at a 7 percent discount rate would be \$2 (\$2019) in the year 2050, while the SCC for global economic impacts at a 2.5 percent discount rate would be approximately \$121 (\$2019), or more than 60 times the estimate the Trump administration relies on. These changes directly contradict the fundamental purpose of the SCC.

In the current rulemaking, EPA inappropriately applies a domestic SCC, and uses discount rates of both 3% and 7%.[681] The correct SCC to apply is the global SCC using 2.5 percent and 3 percent discount rates, as given in the table below.

Table SCC 1: Social Cost of Carbon, 2010-2050 (in 2007 dollars per metric ton of CO_2).[682]

Year	5% Average	**3% Average**	2.5% Average
2010	10	**31**	50
2015	11	**36**	56
2020	12	**42**	62
2025	14	**46**	68
2030	16	**50**	73
2035	18	**55**	78
2040	21	**60**	84
2045	23	**64**	89
2050	26	**69**	95

For these comments, NRDC calculated the CO2 emissions implications of various regulatory scenarios using the IPM modeling described above.[683] NRDC then calculated the economic impacts of these emissions changes using the global SCC estimates shown in Table SCC 1.

The simulations show that Options 2 and 4 would both generate substantial economic costs associated with increased CO2 emissions, while a zero-discharge "Option 5" would generate an economic benefit associated with reduced CO2 emissions. The annualized benefits under Option 5 total $48-71 million ($2019) in 2046 compared with the NRDC business-as-usual case. By contrast, EPA's Option 2 and Option 4 would deliver annualized costs of $868-1,282 million and $361-533 million, respectively. Between EPA Option 4 and Option 5, the absolute difference between 2046 annualized costs and benefits is between $410-605 million, as shown in Table SCC 2. below. As shown in Table SCC 3, on a cumulative basis over the 2021-2046 time period, Option 5 is projected to deliver $677-1,000 million in *benefits*, compared with costs of $5,476-8,084 million under EPA Option 2 and $665-981 million under EPA Option 4.

Table SCC 2. 2046 Annualized Costs of CO_2 Emissions Due to Changes in Electricity Generation, Incremental to Respective Baseline Scenarios

	3%	2.50%
EPA O4	361,112,333	533,070,587
EPA O2	868,526,419	1,282,110,428
NRDC O5	(48,389,248)	(71,431,747)

Table SCC 3. 2021 – 2046 Cumulative Costs of CO_2 Emissions Due to Changes in Electricity Generation, Incremental to Respective Baseline Scenarios

	3%	2.50%
EPA O4	664,873,285	981,479,612
EPA O2	5,476,374,221	8,084,171,469
NRDC O5	(677,449,471)	(1,000,044,457)

EPA's inappropriate application of the domestic SCC devaluing future generations pursuant to the Trump administration's executive order substantially understates the costs of increased pollution driven by its proposed approaches.

Using the correct SCC estimates would radically change EPA's "net benefit analysis," in which EPA determined that its Option 2 had the highest net value. Using a 3 percent discount rate, EPA derived an annualized, mid-range net value of $155.9 million for Option 2.[684] By contrast, using the correct SCC, the costs of increased CO2 emissions under Options 2 and 4 dominate other costs and benefits and result in a large net cost, as shown in Table SCC 4 below, with Option 2 having the highest net cost. Option 5, on the other hand, produces a large net benefit.

Table SCC 4: Annualized Benefits, Costs, and "Net Benefits" (millions of $2018)

	CO_2 Benefits[685]	Other Benefits[686]	Total Benefits	Costs[687]	Net
Option 2	$ (851.86)	$ 51.20	$ (800.66)	$ (136.30)	$ (936.96)
Option 4	$ (354.83)	$ 110.70	$ (244.13)	$ 11.90	$ (232.23)
Option 5	$ 47.48	$ 110.70[688]	$ 158.18	$ 30.80	$ 188.98

Table SCC 4 shows two important things. First, use of the correct SCC value would result in Option 2 having a much lower net value (higher net cost) than Option 4. In other words, EPA can only find that Option 2 has the highest net value by distorting the science and failing to adequately account for the economic costs of CO2 emissions.

Second, the most economically defensible regulatory option – and the only one that produces a net benefit – is a zero-discharge rule.

EPA must accurately account for the economic consequences of its decision-making, and that means that the Agency must use a defensible SCC. Doing so would show that a zero-discharge rule, eliminating the discharge of both bottom ash transport water and FGD wastewater, is the most economically defensible regulatory option. This, combined with the fact that a zero-discharge rule is required by the CWA because zero-discharge technologies are BAT for both wastestreams,[689] confirms that EPA has no justification for any regulatory option other than a zero-discharge rule.

[679] See Table SCC 1 below, with the 2020 value at 3% ($42) adjusted from $2007 to $2020.
[680] Proposed BCA at I-5.
[681] Proposed BCA at 8-7.
[682] EPA, Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, at 4 (Aug. 2016), https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.
[683] See Section XIII.D – IPM Modeling.
[684] Proposed BCA at 13-2, Tbl. 13-2.
[685] See Table SCC 2, adjusted to $2018.
[686] Proposed BCA at 11-2, Tbl. 11-1.
[687] Id. at 13-1, Tbl. 13-1.
[688] We could not calculate the other benefits of a zero-discharge regulatory option, so we conservatively assumed that they would be equal to those under Option 4.
[689] See Sections V- Bottom Ash and VI – Zero Discharge FGD.

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Comment Excerpt:

2. EPA Fails to Appropriately Consider the Unquantified Costs of the Proposed Deregulation

In addition to its failure to adequately account for the costs of carbon emissions, EPA also fails to adequately address the numerous unquantified costs of the proposed deregulation.

Specifically, EPA recognizes that the proposed deregulation will result in numerous unquantified health impacts, including increases in premature mortality and non-fatal diseases (such as heart attacks, bronchitis, and cardiovascular disease) by increasing emissions in nitrogen oxides and sulfur dioxide.[223] Moreover, as detailed above, the social cost of carbon fails to account for many of the damages associated with an increase in carbon emissions, meaning that the increase in carbon emissions from the proposed deregulation will also result in significant unquantified costs. [224]

Yet EPA only briefly ticks through these unquantified or nonmonetized costs of the proposed deregulation, and does not consider their likely scope or magnitude when assessing whether the rule is cost-justified. In fact, EPA provides a schedule of benefits from avoided emissions of particulate matter precursors like nitrogen oxides and sulfur dioxide, but then notes that it has chosen *not* to monetize the effects from changes in these pollutants due to the deregulation.[225]

EPA's selective treatment of costs is arbitrary and insufficient. Circular A-4 requires agencies to not only "identify" non-monetary costs and benefits, but to also "highlight (e.g., with categories or rank ordering) those that [it] believe[s] are most important" and to "evaluate their significance" by quantifying their impact to the extent possible and then qualitatively comparing that impact to other costs and benefits.[226] Merely determining that a regulation is justified because monetized benefits exceed monetized costs is insufficient: The Circular cautions that "the most efficient alternative will not necessarily be the one with the largest quantified and monetized net-benefit estimate."[227] Consistent with this guidance, EPA must fully disclose the limitations of its social cost of greenhouse gas estimates and assess the significance of all the unquantified health, climate, and economic costs.

EPA's list of unquantified costs and cursory reference to "impact categories omitted"[228] from the social cost of carbon falls well short of this standard. First, the fact that EPA's "modeling capacity was fully allocated" to other misguided deregulatory efforts[229] is a poor excuse for failing to monetize significant damages from increased nitrogen oxide and sulfur dioxide emissions here. Second, to the extent that there remain costs to the rule that EPA cannot monetize, it must appropriately *weigh* all such non-monetized costs, not merely recognize that they exist without further discussion. This applies both to any unaccounted climate impacts from carbon emissions and non-monetized health and productivity costs from particulate matter and ozone emissions. Only then can EPA determine whether all of the proposal's costs, monetized and non-monetized alike, can be justified by the purported benefits of the proposed deregulation.

For these reasons, as well, the economic analysis underlying the proposed deregulation is fundamentally lawed, and any final rulemaking relying on a similar analysis would be arbitrary and capricious.

223 BCA at 8-4.
224 Peter Howard, *Omitted Damages: What's Missing from the Social Cost of Carbon* 5 (Cost of Carbon Project Report, 2014), http://costofcarbon.org/ (describing how greenhouse gas damage estimates omit or poorly quantify numerous damage categories).
225 BCA at 8-5.
226 Circular A-4 at 2, 27.
227 *Id.* at 2.
228 BCA I-3.
229 BCA at 8-5.

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Comment Excerpt:

Technical Appendix: Uncertainty

Contrary to the arguments made by many opposed to strong federal climate action, uncertainty about the full effects of climate change *raises* the social cost of greenhouse gases and warrants *more* stringent climate policy.[1] Integrated assessment models (IAMs) currently used to calculate the social cost of carbon (SCC) show that the net effect of uncertainty about economic damage resulting from climate change, costs of mitigation, future economic development, and many other parameters raises the SCC compared to the case where models simply use our current best guesses of these parameters.[2] Even so, IAMs still underestimate the impact of uncertainty on the SCC by not accounting for a host of fundamental features of the climate problem: the irreversibility of climate change, society's aversion to risk and other social preferences, option value, and many catastrophic impacts.[3] Rather than being a reason not to take action, uncertainty increases the SCC and should lead to more stringent policy to address climate change.[4]

Types of Uncertainty in the IAMs

IAMs incorporate two types of uncertainty: parametric uncertainty and stochastic uncertainty. Parametric uncertainty covers uncertainty in model design and inputs, including the selected parameters, correct functional forms, appropriate probability distribution functions, and model structure. With learning, these uncertainties should decline over time as more information becomes available.[5] Stochastic uncertainty is persistent randomness in the economic-climate system, including various environmental phenomena such as volcanic eruptions and sun spots.[6] Uncertainties are present in each component of the IAMs: socioeconomic scenarios, the simple climate model, the damage and abatement cost functions, and the social welfare function (including the discount rate).[7]

When modeling climate change uncertainty, scientists and economists have long emphasized the importance of accounting for the potential of catastrophic climate change.[8] Catastrophic outcomes combine several overlapping concepts including unlucky states of the world (i.e., bad draws), deep uncertainty, and climate tipping points and elements.[9] Traditionally, IAM developers address uncertainty by specifying probability distributions over various climate and economic parameters. This type of uncertainty implies the possibility of an especially bad draw if multiple uncertain parameters turn out to be lower than we expect, causing actual climate damages to greatly exceed expected damages.

Our understanding of the climate and economic systems is also affected by so-called "deep uncertainty," which can be thought of as uncertainty over the true probability distributions for specific climate and economic parameters.[10] The mean and variance of many uncertain climate phenomena are unknown due to lack of data, resulting in "fat-tailed distributions"—i.e., the tail of the distributions decline to zero slower than the normal distribution. Fat-tailed distributions result when the best guess of the distribution is derived under learning.[11] Given the general opinion that bad surprises are likely to outweigh good surprises in the case of climate change,[12] modelers capture deep uncertainty by selecting probability distributions with a fat upper tail which reflects the greater likelihood of extreme events.[13] The possibility of fat tails increases the likelihood of a "very" bad draw with high economic costs, and can result in a very high (and potentially infinite) expected cost of climate change (a phenomenon known as the dismal theory).[14]

Climate tipping elements are environmental thresholds where a small change in climate forcing can lead to large, non-linear shifts in the future state of the climate (over short and long periods of time) through positive feedback (i.e., snowball) effects.[15] Tipping points refer to economically relevant thresholds after which change occurs rapidly (i.e., Gladwellian tipping points), such that opportunities for adaptation and intervention are limited.[16] Tipping point examples include the reorganization of the Atlantic meridional overturning circulation (AMOC) and a shift to a more persistent El Niño regime in the Pacific Ocean.[17] Social tipping points—including climate-induced migration and conflict—also exist. These various tipping points interact, such that triggering one tipping point may affect the probabilities of triggering other tipping points.[18] There is some overlap between tipping point events and fat tails in that the probability distributions for how likely, how quick, and how damaging tipping points will be are unknown.[19] Accounting fully for these most pressing, and potentially most dramatic, uncertainties in the climate-economic system matter because humans are risk averse and tipping points—like many other aspects of climate change—are, by definition, irreversible

How IAMs and the IWG Account for Uncertainty

Currently, IAMs (including all of those used by the IWG) capture uncertainty in two ways: deterministically and through uncertainty propagation. For the deterministic method, the modeler assumes away uncertainty (and thus the possibility of bad draws and fat tails) by setting parameters equal to their most likely (median) value. Using these values, the modeler calculates the median SCC value. Typically, the modeler conducts sensitivity analysis over key parameters—one at a time or jointly—to determine the robustness of the modeling results. This is the approach employed by Nordhaus in the preferred specification of the DICE model[20] used by the IWG.

Uncertainty propagation is most commonly carried out using Monte Carlo simulation. In these simulations, the modeler randomly draws parameter values from each of the model's probability distributions, calculates the SCC for the draw, and then repeats this exercise thousands of times to calculate a mean social cost of carbon.[21] Tol, Anthoff, and Hope employ this technique in FUND and PAGE—as did the IWG (2010, 2013, and 2016)—by specifying probability distributions for the climate and economic parameters in the models. These models are especially helpful for assessing the net effect of different parametric and stochastic uncertainties. For instance, both the costs of mitigation and the damage from climate change are uncertain. Higher costs would warrant less stringent climate policies, while higher damages lead to more stringent policy, so theoretically, the effect of these two factors on climate policy could be ambiguous. Uncertainty propagation in an IAM calibrated to empirically motivated distributions, however, shows that climate damage uncertainty outweighs the effect of cost uncertainty, leading to a stricter policy when uncertainty is taken into account than when it is ignored.[22] This can be seen in the resulting right-skewed distribution of the SCC (see Figure 1 in IWG (2016)) where the mean (Monte Carlo) SCC value clearly exceeds the median (deterministic) SCC value.

The IWG was rigorous in addressing uncertainty. First, it conducted Monte Carlo simulations over the above IAMs specifying different possible outcomes for climate sensitivity (represented by a right skewed, fat tailed distribution to capture the potential of higher than expected warming). It also used scenario analysis: five different emissions growth scenarios and three discount rates. Second, the IWG (2016) reported the various moments and percentiles—including the 95th percentile—of the resulting SCC estimates. Third, the IWG put in place an updating process, e.g., the 2013 and 2016 revisions, which updates the models as new information becomes available.[23] As such, the IWG used the various tools that economists have developed over time to address the uncertainty inherent in estimating the economic cost of pollution: reporting various measures of uncertainty, using Monte Carlo simulations, and updating estimates as evolving research advances our knowledge of climate change. Even so, the IWG underestimates the SCC by failing to capture key features of the climate problem.

Current IAMs Underestimate the SCC by Failing to Sufficiently Model Uncertainty

Given the current treatment of uncertainty by the IWG (2016) and the three IAMs that they employ, the IWG (2016) estimates represent an underestimate of the SCC. DICE clearly underestimates the true value of the SCC by effectively eliminating the possibility of bad draws and fat tails through a deterministic model that relies on the median SCC value. Even with their calculation of the mean SCC, the FUND and PAGE also underestimate the metric's true value by ignoring key features of the climate-economic problem. Properly addressing the limitations of these models' treatment of uncertainty would further increase the SCC.

First, current IAMs insufficiently model catastrophic impacts. DICE fails to model both the possibility of bad draws and fat tails by applying the deterministic approach. Alternatively, FUND and PAGE ignore deep uncertainty by relying predominately on the thin-tailed triangular and gamma distributions.[24] The IWG (2010) only partially addresses this oversight by replacing the ECS parameter in DICE, FUND, and PAGE with a fat-tailed, right-skewed distribution calibrated to the IPCC's assumptions (2007), even though many other economic and climate phenomenon in IAMs are likely characterized by fat tails, including climate damages from high temperature levels, positive climate feedback effects, and tipping points.[25] Recent work in stochastic dynamic programming tends to better integrate fat tails – particularly with respect to tipping points (see below) – and address additional aversion to this type of uncertainty (also known as ambiguity aversion); doing so can further increase the SCC under uncertainty.[26]

In contrast to their approach to fat tails, the IAMs used by the IWG (2010; 2013; 2016) sometimes address climate tipping points, though they do not apply state-of-the-art methods for doing so. In early versions of DICE (DICE-2010 and earlier), Nordhaus implicitly attributes larger portions of the SCC to tipping points by including certainty equivalent damages of catastrophic events - representing two-thirds to three-quarter of damages in DICE – calibrated to an earlier Nordhaus (1994) survey of experts.[27] In PAGE09, Hope also explicitly models climate tipping points as a singular, discrete event (of a 5% to 25% loss in GDP) that has a probability (which grows as temperature increases) of occurring in each time period.[28] Though not in the preferred versions of the IAMs employed by the IWG, some research also integrates specific tipping points into these IAMs finding even higher SCC estimates.[29] Despite the obvious methodological basis for addressing tipping points, the latest versions of DICE[30] and FUND exclude tipping points in their preferred specifications. Research shows that if these models were to correctly account for the full range of climate impacts—including tipping points—the resulting SCC estimates would increase.[31]

The IWG approach also fails to include a risk premium—that is, the amount of money society would require in order to accept the uncertainty (i.e., variance) over the magnitude of warming and the resulting damages from climate change relative to mean damages (IWG, 2010; IWG, 2015)). The mean of a distribution, which is a measure of a distribution's central tendency, represents only one descriptor or "moment" of a distribution's shape. Each IAM parameter and the resulting SCC distributions have differing levels of variance (i.e., spread around the mean), skewness (i.e., a measure of asymmetry), and kurtosis (which, like skewness, is another descriptor of a distribution's tail) as well as means.[32] It is generally understood that people are risk averse in that they prefer input parameter distributions and (the resulting) SCC distributions with lower variances, holding the mean constant.[33] While the IWG assumes a risk-neutral central planner by using a constant discount rate (setting the risk premium to zero), this assumption does not correspond with empirical evidence,[34] current IAM assumptions,[35] the NAS (2017) recommendations, nor with the IWG's own discussion (2010) of the possible values of the elasticity of the marginal utility of consumption. Evidence from behavioral experiments indicate that people and society are also averse to other attributes of parameter distributions – specifically to the thickness of the tails of distributions – leading to an additional ambiguity premium (Heal and Millner, 2014).[36] Designing IAMs to properly account for the risk and ambiguity premiums from uncertain climate damages would increase the resulting SCC values they generate.

Even under the IWG's current assumption of risk neutrality, the mean SCC from uncertainty propagation excludes the (real) option value of preventing marginal CO^2 emissions.[37] Option value reflects the value of future flexibility due to uncertainty and irreversibility; in this case, the irreversibility of CO2 emissions due to their long life in the atmosphere.[38] If society exercises the option of emitting an additional unit of CO2 emissions today, "we will lose future flexibility that the [mitigation] option gave" leading to possible "regret and…a desire to 'undo'" the additional emission because it "constrains future behavior."[39] Given that the SCC is calculated on the Business as Usual (BAU) emission pathway, option value will undoubtedly be positive for an incremental emission because society will regret this emission in most possible futures.

Though sometimes the social cost of carbon and a carbon tax are thought of as interchangeable ways to value climate damages, agencies should be careful to distinguish two categories of the literature. The first is the economic literature that calculates the optimal carbon tax in a scenario where the world has shifted to an optimal emissions pathway. The second is literature that assesses the social cost of carbon on the business-as-usual (BAU) emissions pathway; the world is currently on the BAU pathway, since optimal climate policies have not been implemented. There are currently no numerical estimates of the risk premium and option value associated with an incremental emission on the BAU emissions path. Although there are stochastic dynamic optimization models that implicitly account for these two values, they analyze *optimal,* sequential decision making under climate uncertainty.[40] By nature of being optimization models (instead of policy models), these complex models focus on calculating the optimal tax and not the social cost of carbon, which differ in that the former is the present value of marginal damages on the optimal emissions path rather than on the BAU emissions path.[41] While society faces the irreversibility of emissions on the BAU emissions path when abatement is essentially near zero (i.e., far below the optimal level even in the deterministic problem),[42] the stochastic dynamic optimization model must also account for a potential counteracting abatement cost irreversibility – the sunk costs of investing in abatement technology if we learn that climate change is less severe than expected – by the nature of being on the optimal emissions path that balances the cost of emissions and abatement. In the optimal case, uncertainty and irreversibility of abatement *can theoretically* lead to a lower optimal emissions tax, unlike the social cost of carbon. The difference in the implication for the optimal tax and the SCC means that the stochastic dynamic modeling results are less applicable to the SCC.

What can we learn from new literature on stochastic dynamic programming models?

Bearing in mind the limitations of stochastic dynamic modeling, some new research provides valuable insights that are relevant to calculation of the social cost of greenhouse gases. The new and growing stochastic dynamic optimization literature implies that the IWG's SCC estimates are downward biased. The literature is made up of three models – real option, finite horizon, and infinite horizon models – of which the infinite time horizon (i.e., stochastic dynamic programming (SDP)) models are the most comprehensive for analyzing the impact of uncertainty on optimal sequential abatement policies.[43] Recent computational advancements in SDP are helping overcome the need for strong simplifying assumptions in this literature for purpose of tractability. Traditionally, these simplifications led to unrealistically fast rates of learning – leading to incorrect outcomes – and difficulty in comparing results across papers (due to differing uncertain parameters, models of learning, and model types). Even so, newer methods still only allow for a handful of uncertain parameters compared to the hundreds of uncertain parameters in FUND and PAGE. Despite these limitations, the literature supports the above finding that the SCC, if anything, increases under uncertainty.[44]

First, uncertainty increases the optimal emissions tax under realistic parameter values and modeling scenarios. While the impact of uncertainty on the optimal emissions tax (relative to the deterministic problem) depends on the uncertain parameters considered, the type of learning, and the model type (real option, finite horizon, and infinite horizon), the optimal tax clearly increases when tipping points or black swan events are included in stochastic optimization problems.[45] For SDP models, uncertainty tends to strengthen the optimal emissions path relative to the determinist case even without tipping points,[46] and these results are strengthened under realistic preference assumptions.[47] Given that there is no counterbalancing tipping abatement cost,[48] the complete modeling of climate uncertainty – which fully accounts for tipping points and fat tails – increases the optimal tax. Uncertainty leads to a stricter optimal emissions policy even if with irreversible mitigation costs, highlighting that the SCC would also increase when factoring in risk aversion and irreversibility given that abatement costs are very low on the BAU emissions path.

Second, given the importance of catastrophic impacts under uncertainty (as shown in the previous paragraph), the full and accurate modeling of tipping points and unknown knowns is critical when modeling climate change. The most sophisticated climate-economic models of tipping points – which include the possibility of multiple correlated tipping points in stochastic dynamic IAMs – find an increase in the optimal tax by 100%[49] to 800%[50] relative to the deterministic case without them. More realistic modeling of tipping points will also increase the SCC.

Finally, improved modeling of preferences will amplify the impact of uncertainty on the SCC. Adopting Epstein-Zin preferences that disentangle risk aversion and time preferences can significantly increase the SCC under uncertainty.[51] Recent research has shown that accurate estimation of decisions under uncertainty crucially depends on distinguishing between risk and time preferences.[52] By conflating risk and time preferences, current models substantially understate the degree of risk aversion exhibited by most individuals, artificially lowering the SCC. Similarly, adopting ambiguity aversion increase the SCC, but to a much lesser extent than risk aversion.[53] Finally, allowing for the price of non-market goods to increase with their relative scarcity can amplify the positive effect that even small tipping points have on the SCC if the tipping point impacts non-market services.[54] Including more realistic preference assumptions in IAMs would further increase the SCC under uncertainty.

Introducing stochastic dynamic modeling (which captures option value and risk premiums), updating the representation of tipping points, and including more realistic preference structures in traditional IAMs will – as in the optimal tax – further increase the SCC under uncertainty

Conclusion: Uncertainty Raises the Social Cost of Greenhouse Gases

Overall, the message is clear: climate uncertainty is *never* a rationale for ignoring the SCC or shortening the time horizon of IAMs. Instead, our best estimates suggest that increased variability implies a higher SCC and a need for more stringent emission regulations.[55] Current omission of key features of the climate problem under uncertainty (the risk and climate premiums, option value, and fat tailed probability distributions) and incomplete modeling of tipping points imply that the SCC will further increase with the improved modeling of uncertainty in IAMs.

1 Peterson (2006) states "Most modeling results show (as can be expected) that there is optimally more emission abatement if uncertainties in parameters or the possibility of catastrophic events are considered." Peterson, S. (2006). Uncertainty and economic analysis of climate change: A survey of approaches and findings. *Environmental Modeling & Assessment*, *11*(1), 1-17.

2 Tol, R. S. (1999). Safe policies in an uncertain climate: an application of FUND. *Global Environmental Change*, *9*(3), 221- 232; Peterson, S. (2006). Uncertainty and economic analysis of climate change: A survey of approaches and findings. *Environmental Modeling & Assessment*, *11*(1), 1-17; Interagency Working Group on Social Cost of Carbon, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12,866 (2016).

3 Pindyck, R. S. (2007). Uncertainty in environmental economics. *Review of environmental economics and policy*, *1*(1), 45-65; Golub, A., Narita, D., & Schmidt, M. G. (2014). Uncertainty in integrated assessment models of climate change: Alternative analytical approaches. *Environmental Modeling & Assessment*, *19*(2), 99-109; Lemoine, D., & Rudik, I. (2017). Managing Climate Change Under Uncertainty: Recursive Integrated Assessment at an Inflection Point. *Annual Review of Resource Economics* 9:18.1-18.26.

4 *See* cites *supra* note 3.

5 Learning comes in multiple forms: passive learning of anticipated information that arrives exogenous to the emission policy (such as academic research), active learning of information that directly stems from the choice of

the GHG emission level (via the policy process), and learning of unanticipated information (Kann and Weyant, 2000; Lemoine and Rudik, 2017).

6 Kann, A., & Weyant, J. P. (2000). Approaches for performing uncertainty analysis in large-scale energy/economic policy models. *Environmental Modeling & Assessment*, *5*(1), 29-46; Peterson (2006), *supra* note 1; Golub et al. *supra* note 3. A potential third type of uncertainty arises due to ethical or value judgements: normative uncertainty. Peterson (2006) *supra* note 1; Heal, G., & Millner, A. (2014). Reflections: Uncertainty and decision making in climate change economics. *Review of Environmental Economics and Policy*, *8*(1), 120-137. For example, there is some normative debate over the appropriate consumption discount rate to apply in climate economics, though widespread consensus exists that using the social opportunity cost of capital is inappropriate (see earlier discussion). Preference uncertainty should be modeled as a declining discount rate over time (see earlier discussion), not using uncertain parameters. Kann & Weyant, *supra* note 6.

7 Peterson (2006), *supra* note 1; Pindyck (2007), *supra* note 3; Heal & Millner, *supra* note 6.

8 Nordhaus, W. D. (2008). A question of balance: Weighing the options on global warming policies. Yale University Press; Kopp, R. E., Shwom, R. L., Wagner, G., & Yuan, J. (2016). Tipping elements and climate–economic shocks: Pathways toward integrated assessment. *Earth's Future*, *4*(8), 346-372.

9 Kopp et al. (2016), *supra* note 8.

10 *Id.*

11 Nordhaus, W. D. (2009). An Analysis of the Dismal Theorem (No. 1686). Cowles Foundation Discussion Paper; Weitzman, M. L. (2011). Fat-tailed uncertainty in the economics of catastrophic climate change. Review of Environmental Economics and Policy, 5(2), 275-292; Pindyck, R. S. (2011). Fat tails, thin tails, and climate change policy. *Review of Environmental Economics and Policy*, *5*(2), 258-274.

12 Mastrandrea, M. D. (2009). Calculating the benefits of climate policy: examining the assumptions of integrated assessment models. Pew Center on Global Climate Change Working Paper; Tol, R. S. (2012). On the uncertainty about the total economic impact of climate change. *Environmental and Resource Economics*, *53*(1), 97-116.

13 Weitzman (2011), *supra* note 11, makes clear that "deep structural uncertainty about the unknown unknowns of what might go very wrong is coupled with essentially unlimited downside liability on possible planetary damages. This is a recipe for producing what are called ‘fat tails’ in the extreme of critical probability distributions.”

14 Weitzman, M. L. (2009). On modeling and interpreting the economics of catastrophic climate change. The Review of Economics and Statistics, 91(1), 1-19; Nordhaus (2009), *supra* note 11; Weitzman (2011), *supra* note 11.

15 Tipping elements are characterized by: (1) deep uncertainty, (2) absence from climate models, (3) larger resulting changes relative to the initial change crossing the relevant threshold, and (4) irreversibility. Kopp et al. (2016), *supra* note 8.

16 *Id.*

17 *Id.*; Kriegler, E., Hall, J. W., Held, H., Dawson, R., & Schellnhuber, H. J. (2009). Imprecise probability assessment of tipping points in the climate system. *Proceedings of the national Academy of Sciences*, *106*(13), 5041-5046; Diaz, D., & Keller, K. (2016). A potential disintegration of the West Antarctic Ice Sheet: Implications for economic analyses of climate policy. *The American Economic Review*, *106*(5), 607-611. See Table 1 of Kopp et al. (2016) *supra* note 8, for a full list of known tipping elements and points.

18 Kriegler et al. (2009), *supra* note 17; Cai, Y., Lenton, T. M., & Lontzek, T. S. (2016). Risk of multiple interacting tipping points should encourage rapid CO2 emission reduction; Kopp et al. (2016) *supra* note 8.

19 Peter Howard, *Omitted Damages: What’s Missing from the Social Cost of Carbon* 5 (Cost of Carbon Project Report, 2014), http://costofcarbon.org/; Kopp et al. (2016) *supra* note 8.

20 Nordhaus, W. & Sztorc, P. (2013). DICE 2013: Introduction & User’s Manual. Retrieved from Yale University, Department of Economics website: http://www.econ.yale.edu/~nordhaus/homepage/documents/Dicemanualfull

21 In alternative calculation method, the modeler “performs optimization of polices for a large number of possible parameter combinations individually and estimates their probability weighted sum.” Golub et al. *supra* note 3. In more recent DICE-2016, Nordhaus conducts a three parameter analysis using this method to determine a SCC confidence interval. Given that PAGE and FUND model hundred(s) of uncertainty parameters, this methodology appears limited in the number of uncertain variables that can be easily specified.

22 Tol (1999), *supra* note 2, in characterizing the FUND model, states, "Uncertainties about climate change impacts are more serious than uncertainties about emission reduction costs, so that welfare-maximizing policies are stricter under uncertainty than under certainty."
23 IWG (2010).
24 Howard (2014), *supra* note 19. While both FUND and PAGE employ thin tailed distributions, the resulting distribution of the SCC is not always thin-tailed. In PAGE09, the ECS parameter is endogenous, such that the distribution of the ECS has a long tail following the IPCC (2007). *See* Chen, Z., Marquis, M., Averyt, K. B., Tignor, M., & Miller, H. L. (2007). Contribution of working group I to the fourth assessment report of the intergovernmental panel on climate change. *Cambridge, UK and New York: Cambridge University Press, 996p*. Similarly, while Anthoff and Tol do not explicitly utilize fat-tail distributions, the distribution of net present welfare from a Monte Carlos simulation is fat tailed. Anthoff, D., & Tol, R. S. (2014). The Climate Framework for Uncertainty, Negotiation and Distribution (FUND): Technical description, Version 3.8. Available at www.fundmodel. org. Explicitly modeling parameter distributions as fat tailed may further increase the SCC.
25 Weitzman (2011), *supra* note 11; Kopp et al. (2016) *supra* note 8.
26 Lemoine, D., & Traeger, C. P. (2016a). Ambiguous tipping points. *Journal of Economic Behavior & Organization*, *132*, 5- 18; Lemoine & Rudik (2017), *supra* note 3. IAM modelers currently assume that society is equally averse to known unknown and known unknowns. Lemoine & Traeger, *supra* note 26.
27 Nordhaus, W. D., & Boyer, J. (2000). Warning the World: Economic Models of Global Warming. MIT Press (MA); Nordhaus, W. D. (2008). A question of balance: Weighing the options on global warming policies. Yale University Press; Howard (2014), *supra* note 19; Kopp et al. (2016) *supra* note 8.
28 Hope (2006) also calibrated a discontinuous damage function in PAGE-99 used by IWG (2010). Howard (2014), *supra* note 19.
29 Kopp et al. (2016) *supra* note 8.
30 For DICE-2013 and DICE-2016, Nordhaus calibrates the DICE damage function using a meta-analysis based on estimates that mostly exclude tipping point damages. Howard, P. H., & Sterner, T. (2016). Few and Not So Far Between: A Meta-analysis of Climate Damage Estimates. *Environmental and Resource Economics*, 1-29.
31 Using FUND, Link and Tol (2010) find that a collapse of the AMOC would decrease GDP (and thus increase the SCC) by a small amount. Earlier modeling of this collapse in DICE find a more significance increase. Keller, K., Tan, K., Morel, F. M., & Bradford, D. F. (2000). Preserving the ocean circulation: implications for climate policy. *Climatic Change*, *47*, 17-43; Mastrandrea, M. D., & Schneider, S. H. (2001). Integrated assessment of abrupt climatic changes. *Climate Policy*, *1*(4), 433-449; Keller, K., Bolker, B. M., & Bradford, D. F. (2004). Uncertain climate thresholds and optimal economic growth. *Journal of Environmental Economics and management*, *48*(1), 723-741. With respect to thawing of the permafrost, Hope and Schaefer (2016), Economic impacts of carbon dioxide and methane released from thawing permafrost. *Nature Climate Change*, *6*(1), 56- 59, and Gonzalez-Eguino and Neumann (2016), González-Eguino, M., & Neumann, M. B. (2016). Significant implications of permafrost thawing for climate change control. *Climatic Change*, *136*(2), 381-388, find increases in damages (and thus an increase in the SCC) when integrating this tipping element into the PAGE09 and DICE-2013R, respectively. Looking at the collapse of the West Antarctic Ice sheet, Nicholls et al. (2008) find a potential for significant increases in costs (and thus the SCC) in FUND. Nicholls, R. J., Tol, R. S., & Vafeidis, A. T. (2008). Global estimates of the impact of a collapse of the West Antarctic ice sheet: an application of FUND. *Climatic Change*, *91*(1), 171-191. Ceronsky et al. (2011) model three tipping points (collapse of the Atlantic Ocean Meridional Overturning Circulation, large scale dissociation of oceanic methane hydrates; and a high equilibrium climate sensitivity parameter), and finds a large increase in the SCC in some cases. Ceronsky, M., Anthoff, D., Hepburn, C., & Tol, R. S. (2011). *Checking the price tag on catastrophe: The social cost of carbon under non-linear climate response* (No. 392). ESRI working paper.
32 Golub, A., & Brody, M. (2017). Uncertainty, climate change, and irreversible environmental effects: application of real options to environmental benefit-cost analysis. *Journal of Environmental Studies and Sciences*, 1-8; see Figure 1 in IWG (2016).
33 In other words, society prefers a narrow distribution of climate damages around mean level of damages X to a wider distribution of damages also centered on the same mean of X because they avoid the potential for very high damages even at the cost of eliminating the chance of very low damages.

34 IWG 2010, *supra* note 23; Cai et al., 2016, *supra* note 18, at 521.
35 The developers of each of the three IAMs used by the IWG (2010; 2013; 2016) assume a risk aversion society. Nordhaus and Sztorc (2013), *supra* note 20; Anthoff, D., & Tol, R. S. (2010). The Climate Framework for Uncertainty, Negotiation and Distribution (FUND): Technical description, Version 3.5. Available at www.fund-model.org; Anthoff, D., & Tol, R. S. (2014). The Climate Framework for Uncertainty, Negotiation and Distribution (FUND): Technical description, Version 3.8. Available at www.fund-model.org; Hope, C. (2013). Critical issues for the calculation of the social cost of CO2: why the estimates from PAGE09 are higher than those from PAGE2002. *Climatic Change*, *117*(3), 531-543.
36 According to Heal and Millner (2014), *supra*, there is an ongoing debate of whether ambiguity aversion is rational or a behavioral mistake. Given the strong possibility that this debate is unlikely to be resolved, the authors recommend exploring both assumptions.
37 Arrow, K. J., & Fisher, A. C. (1974). Environmental preservation, uncertainty, and irreversibility. *The Quarterly Journal of Economics*, 312-319; Dixit, A.K., Pindyck, R.S., 1994. *Investment Under Uncertainty*. Princeton University Press, Princeton, NJ; Traeger, C. P. (2014). On option values in environmental and resource economics. *Resource and Energy Economics*, *37*, 242- 252. In the discrete emission case, there are two overlapping types of option value: real option value and quasi-option value. Real option value is the full value of future flexibility of maintaining the option to mitigate, and mathematically equals the maximal value that can be derived from the option to [emit] now or later (incorporating learning) less the maximal value that can be derived from the possibility to [emit] now or never. Traeger, C. P. (2014). On option values in environmental and resource economics. *Resource and Energy Economics*, *37*, 242-252, equation 5. Quasi-option value is the value of future learning conditional on delaying the emission decision, which mathematically equals the value of mitigation to the decision maker who anticipates learning less the value of mitigation to the decision maker who anticipates only the ability to delay his/her decision, and not learning. *Id.* The two values are related, such that real option value can be decomposed into:

$$\mathrm{DPOV} = \mathrm{Max}\{QOV + SOV - \mathrm{Max}\{NPV, 0\}, 0\} = \mathrm{Max}\{QOV + SOV - \mathrm{SCC}, 0\}$$

where DPOV is the real option value, QOV is quasi-option value, SOV is simple option value (the value of the option to emit in the future condition on mitigating now), and NPV is the expected net present value of emitting the additional unit or the mean SCC in our case. *Id.*
38 Even if society drastically reduced CO2 emissions, CO2 concentrations would continue to rise in the near future and many impacts would occur regardless due to lags in the climate system. Pindyck (2007), *supra* note 3. Uncertainty in environmental economics. *Review of environmental economics and policy*, *1*(1), 45-65.
39 Pindyck (2007), *supra* note 3.
40 Kann & Weyant, *supra* note 6; Pindyck (2007), *supra* note 3; Golub et al. (2014), *supra* note 3.
41 Nordhaus (2014) makes this difference clear when he clarifies that "With an optimized climate policy…the SCC will equal the carbon price…In the more realistic case where climate policy is not optimized, it is conventional to measure the SCC as the marginal damage of emissions along the actual path. There is some inconsistency in the literature on the definition of the path along which the SCC should be calculated. This paper will generally define the SCC as the marginal damages along the baseline path of emissions and output and not along the optimized emissions path." Nordhaus, W. (2014). Estimates of the social cost of carbon: concepts and results from the DICE-2013R model and alternative approaches. *Journal of the Association of Environmental and Resource Economists*, *1*(1/2), 273-312.
42 On the BAU path, emissions far exceed their optimal level even without considering uncertainty. As a consequence, society is likely to regret an additional emission of CO2 in most future states of the world. Alternatively, society is unlikely to regret current abatement levels unless the extremely unlikely scenarios that there is little to no warming and/or damages from climate change.
43 Kann and Weyant (2000), *supra* note 6; Pindyck (2007), *supra* note 3; Golub et al. (2014), *supra* note 3.
44 Kann and Weyant (2000), *supra* note 6; Pindyck (2007), *supra* note 3; Golub et al. (2014), *supra* note 3; Lemoine & Rudik (2017), *supra* note 3. Comparing the optimal tax to the mean SCC is made further difficult by the frequent use of DICE as the base from which most stochastic dynamic optimization models are built. As a consequence, deterministic model runs are frequently the base of comparison for these models. Lemoine & Rudik (2017), *supra* note 3.

45 The real options literature tends to find an increase in the optimal emissions path under uncertainty relative to the deterministic case (Pindyck, 2007), though the opposite is true when modelers account for the possibility of large damages (i.e., tipping point or black swan events) even with a risk-neutral society (Pindyck, 2007; Golub et al., 2014). Solving finite horizon models employing non-recursive methods, modelers find that the results differ depending on the model of learning – the research demonstrates stricter emission paths under uncertainty without learning (with emission reductions up to 30% in some cases) and the impact under passive learning has a relatively small impact due the presence of sunken mitigation investment costs - except when tipping thresholds are included. *See* Golub et al. (2014), *supra* note 3.

46 Using SDP, modelers find that uncertainty over the equilibrium climate sensitivity parameter generally increases the optimal tax by a small amount, though the magnitude of this impact is unclear. *See* Golub et al. (2014), *supra* note 3; Lemoine & Rudik (2017), *supra* note 3. Similarly, non-catastrophic damages can have opposing effects dependent on the parameters changed, though emissions appear to decline overall when you consider their uncertainty jointly.

47 Pindyck (2007), *supra* note 3; Golub et al. (2014), *supra* note 3; Lemoine & Rudik (2017), *supra* note 3.

48 Pindyck (2007), *supra* note 3.

49 Lemoine, D., & Traeger, C. P. (2016b). Economics of tipping the climate dominoes. *Nature Climate Change*.

50 Cai et al., 2016.

51 Cai et al., 2016; Lemoine & Rudik (2017), *supra* note 3. The standard utility function adopted in IAMs with constant relative risk version implies that the elasticity of substitution equals the inversion of relative risk aversion. As a consequence, the society's preferences for the intra-generational distribution of consumption, the intergenerational distribution of consumption, and risk aversion hold a fixed relationship. For purposes of stochastic dynamic programming, this is problematic because this assumption conflates intertemporal consumption smoothing and risk aversion. Botzen, W. W., & van den Bergh, J. C. (2014). Specifications of social welfare in economic studies of climate policy: overview of criteria and related policy insights. *Environmental and Resource Economics*, *58*(1), 1-33. By adopting the Epstein-Zinn utility function which separates these two parameters, modelers can calibrate them according to empirical evidence. For example, Cai et al. (2016) replace the DICE risk aversion of 1.45 and elasticity parameter of 1/1.45 with values of 3.066 and 1.5, respectively.

52 James Andreoni & Charles Sprenger, *Risk Preferences Are Not Time Preferences*, 102 AM. ECON. REV. 3357–3376 (2012).

53 Lemoine, D., & Traeger, C. P. (2016b). Economics of tipping the climate dominoes. *Nature Climate Change*.; Lemoine & Rudik (2017), *supra* note 3.

54 Typically, IAMs assume constant relative prices of consumption goods. Gerlagh, R., and B.C.C. Van der Zwaan. 2002. "Long-term substitutability between environmental and man-made goods." *Journal of Environmental Economics and Management 44*(2):329-345; Sterner, T., and U.M. Persson. 2008. "An Even Sterner Review: Introducing Relative Prices into the Discounting Debate." *Review of Environmental Economics and Policy 2*(1):61-76. By replacing the standard isoelastic utility function in IAMs with a nested CES utility function following Sterner and Persson (2008), Cai et al. (2015) find that even a relatively small tipping point (i.e., a 5% loss) can substantially increase the SCC in the stochastic dynamic setting. Cai, Y., Judd, K. L., Lenton, T. M., Lontzek, T. S., & Narita, D. (2015). Environmental tipping points significantly affect the cost− benefit assessment of climate policies. *Proceedings of the National Academy of Sciences*, *112*(15), 4606-4611.

55 Golub et al. (2014), *supra* note 3, states: "The most important general policy implication from the literature is that despite a wide variety of analytical approaches addressing different types of climate change uncertainty, none of those studies supports the argument that no action against climate change should be taken until uncertainty is resolved. On the contrary, uncertainty despite its resolution in the future is often found to favor a stricter policy." *See also* Comments from Robert Pindyck, to BLM, on the Social Cost of Methane in the Proposed Suspension of the Waste Prevention Rule (submitted Nov. 5, 2017) ("Specifically, my expert opinion about the uncertainty associated with Integrated Assessment Models (IAMs) was used to justify setting the SCCH4 to zero until this uncertainty is resolved. That conclusion does not logically follow and I have rejected it in the past, and I reiterate my rejection of that view again here. While at this time we do not know the Social Cost of Carbon (SCC) or the Social Cost of Methane with precision, we do know that the correct values are well above zero…Because of my concerns about the IAMs used by the now-disbanded Interagency Working Group to compute the SCC and SC-CH4, I have

undertaken two lines of research that do not rely on IAMs…[They lead] me to believe that the SCC is larger than the value estimated by the U.S. Government."

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 191

Comment Excerpt:

EPA's cursory and incomplete "assessment" – only conducted as part of its "Benefit and Cost Analysis" – of the harms to endangered species contains numerous and substantial flaws and clearly understates the impacts on listed species. While any adverse effects to listed species trigger the consultation requirements of the ESA, EPA demonstrates its inability and lack of expertise on the impacts on endangered species through this deficient assessment.

First, it appears that the *Benefit and Cost Analysis for Proposed Revisions to the Steam Electric Power Generating ELGs* only "identified" threatened and endangered species information from sources prior to 2014.[734] All but one of the sources EPA relied upon were drawn from dated information in 2010. Since 2014, FWS listed approximately 148 additional species as threatened or endangered, and designated numerous critical habitats.[735] If EPA did not review listed species information since 2010, the number of species excluded is much higher. Regardless, it is clear that EPA did not attempt to incorporate significant information and numerous species into its "analysis" at all. Instead, EPA engaged in arbitrary and capricious "further analyses" to unilaterally determine which species to review.[736]

Second, EPA excluded species that it "presumed to be extinct, including those not collected for a minimum of 30 years."[737] EPA simply has no expertise or knowledge regarding endangered species to make such arrogant determinations, which is in part why the ESA provides for consultation with the expert agencies on these matters. Further, EPA does not identify why its analysis is scientifically acceptable or in accordance with the ESA's clear requirement to "give the benefit of the doubt to the species."[738]

Third, EPA excluded "endemic species living in waterbodies . . . unlikely to be affected by steam electric power plant discharges."[739] EPA has no expertise to make such determinations, which should properly occur in consultation with the expert wildlife agencies. The life history and mobility of species are often complex, and because many of the toxic pollutants EPA is allowing to be discharged at higher levels bioaccumulate, species impaired by these pollutants can travel both upstream and downstream from the point of discharge. The result is that the zone of influence of power plant discharges is going to be larger than the artificially narrowed scope EPA has identified. EPA ignores real world complexities and employs unsupported assumptions in order to obfuscate the real harms caused to endangered species across the United States from this rulemaking.

Next, EPA excluded species "whose recovery plans i) do not include pollution or water quality issues as factors preventing recovery, and ii) identify habitat destruction (due to damming, stream channelization, water impoundments, wetland drainage, etc.) as a primary factor preventing recovery."[740] The legal standard of the ESA, however, is whether or not an agency action "may affect" listed species – period. Just because a recovery plan does not identify a threat does not mean that the threat is not relevant. EPA can point to no scientific literature that suggests that any living species benefits from exposure to mercury or cadmium, and that is because no such information exists. EPA also cannot claim that because a species is harmed by another threat (e.g., habitat destruction) that it gets a free pass to poison an endangered species or pollute its habitat.

Additionally, EPA excluded listed species "where water quality issues are identified as the primary issue preventing recovery, but where a specific industry or entity not within the scope of the regulatory options is identified as the culprit."[741] In other words, if a species is poisoned by mercury but the purported "culprit" is another industry, then EPA simply ignored those species. This is arbitrary and capricious, and EPA must provide information to the public explaining which species and "culprits" it believes allows EPA to avoid complying with its ESA obligations.

EPA then arbitrarily and without justification excluded "[l]istings due to non-native species introductions and/or hybridization with native or non-native congeners."[742] At a minimum, EPA must explain which species it excluded based on this criterion. To the extent that EPA used this criterion to exclude salmonids, this approach is legally invalid and unprecedented.

Finally, EPA excluded species about which "very little is known, including geographic distribution."[743] This decision fully encapsulates the absurdity of EPA's approach to endangered species conservation and its requirements under the ESA, more generally. The purpose of the consultation process is to involve the expert wildlife agencies because they possess more information about the biology, geographic distribution, and life history than the action agency. If an action agency is simply allowed to claim ignorance and throw up its hands, the Section 7 consultation process becomes meaningless.

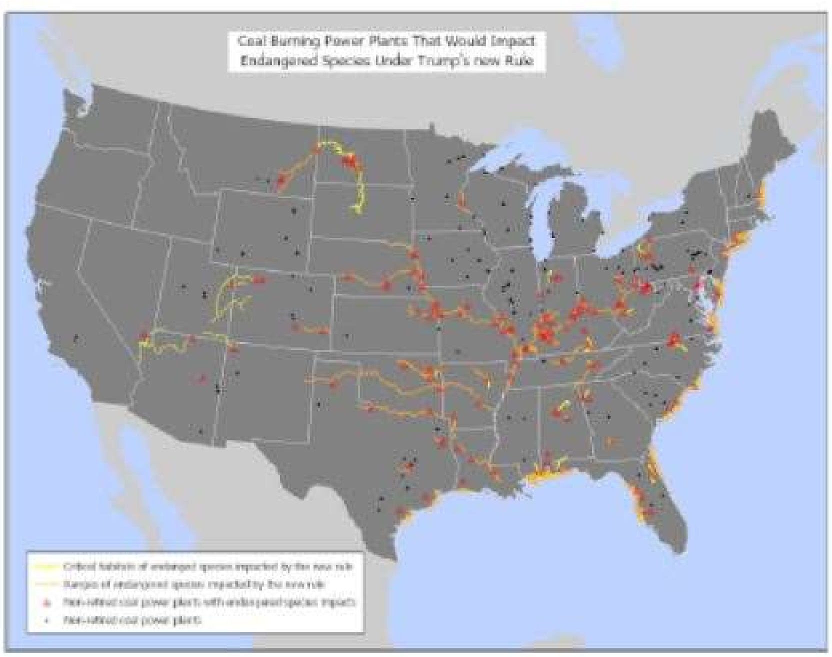
Despite all of this, EPA's own heavily confined "analysis" still identifies twenty-four listed species that will be harmed by the 2019 Proposal. By analyzing the information EPA provided on the rulemaking docket regarding specific power plants that are expected to remain online past 2025, and by using publicly available information provided by the expert wildlife agencies, commenters have identified almost seventy species that are likely to be harmed by the 2019 Proposal. These species include:

Common Name	Scientific Name	Listing Status
Alabama moccasinshell	*Medionidus acutissimus*	Threatened
Arkansas River shiner	*Notropis Girardi*	Threatened

Atlantic pigtoe	*Fusconaia masoni*	Threatened
Black Warrior waterdog	*Necturus alabamensis*	Endangered
Choctaw bean	*Villosa choctawensis*	Endangered
Coosa moccasinshell	*Medionidus parvulus*	Endangered
Colorado pikeminnow	*Ptychocheilus Lucius*	Endangered
Cumberlandian combshell	*Epioblasma brevidens*	Endangered
Cumberland darter	*Etheostoma susanae*	Endangered
Cumberland elktoe	*Alasmidonta atropurpurea*	Endangered
Dark pigtoe	*Pleurobema furvum*	Endangered
Diamond darter	*Crystallaria cincotta*	Endangered
Fat threeridge	*Amblema neislerii*	Endangered
Finelined pocketbook	*Lampsilis altilis*	Threatened
Fluted kidneyshell	*Ptychobranchus subtentum*	Endangered
Georgia pigtoe	*Pleurobema hanleyianum*	Endangered
Gulf moccasinshell	*Medionidus penicillatus*	Endangered
Atlantic sturgeon (Gulf subspecies)	*Acipenser oxyrinchus*	Threatened
Interrupted rocksnail	*Leptoxis foreman*	Endangered
Little Colorado spinedace	*Lepidomeda vittata*	Threatened
Loggerhead sea turtle	*Caretta caretta*	Endangered
Laurel dace	*Chrosomus saylori*	Endangered
West Indian manatee	*Trichechus manatus*	Threatened
Narrow pigtoe	*Fusconaia Escambia*	Threatened
Neosho mucket	*Lampsilis rafinesqueana*	Endangered
Orangenacre mucket	*Lampsilis perovalis*	Threatened
Oval pigtoe	*Pleurobema pyriforme*	Endangered
Ovate clubshell	*Pleurobema perovatum*	Endangered
Oyster mussel	*Epioblasma capsaeformis*	Endangered
Purple bean	*Villosa perpurpurea*	Endangered
Purple bankclimber	*Elliptoideus sloatianus*	Threatened
Rabbitsfoot	*Quadrula cylindrical cylindrical*	Threatened
Razorback sucker	*Xyrauchen texanus*	Endangered
Rough hornsnail	*Pleurocera foreman*	Endangered
Round ebonyshell	*Fusconaia rotulata*	Endangered
Rush darter	*Etheostoma phytophilum*	Endangered
Southern clubshell	*Pleurobema decisum*	Endangered
Southern pigtoe	*Pleurobema georgianum*	Endangered
Shinyrayed pocketbook	*Lampsilis subangulata*	Endangered
Southern kidneyshell	*Ptychobranchus jonesi*	Endangered
Southern sandshell	*Hamiota australis*	Threatened
Spotfin chub	*Erimonax monachus*	Threatened
Triangular kidneyshell	*Ptychobranchus greenii*	Endangered
Trispot darter	*Etheostoma trisella*	Threatened
Piping plover	*Charadrius melodus*	Endangered

Vermilion darter	*Etheostoma chermocki*	Endangered
Virgin River chub	*Gila seminude*	Endangered
Woundfin	*Plagopterus argentissimus*	Endangered
Hawksbill sea turtle	*Eretmochelys imbricate*	Endangered
Least tern	*Sterna antillarum*	Endangered
Ozark hellbender	*Cryptobranchus alleganiensis bishop*	Endangered
Pallid sturgeon	*Scaphirhynchus albus*	Endangered
Purple Cat's paw	*Epioblasma obliguata obliquata*	Endangered
Dromedary pearlymussel	*Dromus dromas*	Endangered
Shiny pigtoe	*Fusconaia cor*	Endangered
Finerayed pigtoe	*Fusconaia cuneolus*	Endangered
Cracking pearlymussel	*Hemistena lata*	Endangered
Pink mucket	*Lampsilis abrupta*	Endangered
Alabama lampmussel	*Lampsilis virescens*	Endangered
Birdwing pearlymussel	*Lemiox rimosus*	Endangered
Ring Pink	*Obvaria retusa*	Endangered
White wartyback	*Plethobasus cicatricosus*	Endangered
Orangefoot pimpleback	*Plethobasus cooperianus*	Endangered
Clubshell	*Pleurobema clava*	Endangered
Rough pigtoe	*Pleurobema plenum*	Endangered
Winged mapleleaf	*Quadrula fragosa*	Endangered
Anthony's riversnail	*Athearnia anthonyi*	Endangered
Fanshell	*Cyprogenia stegaria*	Endangered
Bog turtle	*Clemmys muhlenbergii*	Threatened

Indeed, as the following map illustrates, the overlap between the ranges and critical habitats for these federally-listed species and existing coal-fired power plants are significant and clearly trigger EPA's Section 7 consultation obligations.[744]



[734] Proposed BCA at 5-3.
[735] See FWS, Species Reports, Listed Species Count by Year, https://ecos.fws.gov/ecp0/reports/species-listings-

count-by-year-report (attached).
[736] Proposed BCA at 5-3.
[737] Id. at 5-4.
[738] *Conner v. Burford*, 848 F. 2d 1441, 1454 (9th Cir. 1988); H.R. Conf. Rep. No. 96-697, 96th Cong., 1st Sess. 12, reprinted in 1979 U.S. Code Cong. & Admin. News 2572, 2576.
[739] Proposed BCA at 5-3.
[740] Id.
[741] Id.
[742] Id.
[743] Id.
[744] Commenters are additionally submitting with these comments a spreadsheet (entitled "PowerPlantsvsListedSpecies3.xlsx") with the underlying information used to generate this map (attached).

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Comment Excerpt:

Technical Appendix: Discounting

The Underlying IAMs All Use a Consumption Discount Rate

Employing a consumption discount rate would also ensure that the U.S. government is consistent with the assumptions employed by the underlying IAM models: DICE, FUND, and PAGE. Each of these IAMs employs consumption discount rates calibrated using the standard Ramsey formula (Newell, 2017). In DICE-2010, the elasticity of the pure rate of time preference is 1.5 and an elasticity of the marginal utility of consumption (η) of 2.0. Together with its assumed per capita consumption growth path, the average discount rate over the next three hundred years is 2.4%.[56] However, more recent versions of DICE (DICE- 2013R and DICE-2016) update η to 1.45; this implies an increase of the average discount rate over the timespan of the models to between 3.1% and 3.2% depending on the consumption growth path.[57] In FUND 3.8 and (the mode values in) PAGE09, both model parameters are equal to 1.0. Based on the assumed growth rate of the U.S. economy (without climate damages), the average U.S. discount rate in FUND 3.8 is 2.0% over the timespan of the model (without considering climate damages). Unlike FUND 3.8, PAGE09 specifies triangular distributions for both parameters with a pure rate of time preference of between 0.1 and 2 with a mean of 1.03 and an elasticity of the marginal utility of consumption of between 0.5 and 2 with a mean 1.17. Using the PAGE09's mode values (without accounting for climate damages), the average discount rate over the timespan of the models is approximately 3.3% with a range of 1.2% to 6.5%. Rounding up the annual growth rate over the last 50 years to approximately 2%,[58] the range of best estimates of the SDR implied in the short-run by these three models is approximately 3% (PAGE09's mode estimate and FUND 3.8) to 4.4% (DICE-2016), though the PAGE09 model alone implies a range of 1.1% to 6.0% with a central estimate of 3%. The range of potential consumption discount rates in these IAMs is relatively consistent with IWG (2010; 2013; 2016) in the short-run, though the discount rates of the IAMs employed by the IWG decline over time (due to declining growth rates over time) implying a potential upward bias to the IWG consumption discount rates.

A Declining Discount Rate is Justified to Address Discount Rate Uncertainty

A strong consensus has developed in economics that the appropriate way to discount intergenerational benefits is through a declining discount rate (Arrow et al., 2013; Arrow et al., 2014; Gollier & Hammitt, 2014; Cropper et al., 2014).[59] Not only are declining discount rate theoretically correct, they are actionable (i.e., doable given our current knowledge) and consistent with OMB's *Circular A-4*. Perhaps the best reason to adopt a declining discount rate is the simple fact that there is considerable uncertainty around which discount rate to use. The uncertainty in the rate points directly to the need to use a declining rate, as the impact of the uncertainty grows exponentially over time such that the correct discount rate is not an arithmetic average of possible discount rates.[60] Uncertainty about future discount rates could stem from a number of sources particularly salient in the context of climate change, including uncertainty about future economic growth, consumption, the consumption rate of interest, and preferences. Additionally, economic theory shows that if there is debate or disagreement over which discount rate to use, this should lead to the use of a declining discount rate (Weitzman, 2001; Heal & Millner, 2014). Though, the range of potential discount rates is limited by theory to potential consumption discount rates (see earlier discussion), which is certainly less than 7%.

There is a consensus that declining discount rates are appropriate for intergenerational discounting

Since the IWG undertook its initial analysis and before the most recent estimates of the SCC, a large and growing majority of leading climate economists' consensus (Arrow et al., 2013) has come out in favor of using a declining discount rate for climate damages to reflect long-term uncertainty in interest rates. This consensus view is held whether economists favor descriptive (i.e., market) or prescriptive (i.e., normative) approaches to discounting (Freeman et al., 2015). Several key papers (Arrow et al., 2013; Arrow et al., 2014; Gollier & Hammitt, 2014; Cropper et al., 2014) outline this consensus and present the arguments that strongly support the use of declining discount rates for long-term benefit-cost analysis in both the normative and positive contexts. Finally, in a recent survey of experts on the economics of climate change, Howard and Sylvan (2015) found that experts support using a declining discount rate relative to a constant discount rate at a ratio of approximately 2 to 1.

Economists have recently highlighted two main motivations for using a declining discount rate, which we elaborate on in what follows. First, if the discount rate for a project is fixed but uncertain, then the certainty-equivalent discount rate will decline over time, meaning that benefits should be discounted using a declining rate.[61] Second, uncertainty about the growth rate of consumption or output also implies that a declining discount rate should be used, so long as shocks to consumption are positively correlated over time.[62] In addition to these two arguments, other motivations for declining discount rates have long been recognized. For instance, if the growth rate of consumption declines over time, the Ramsey rule[63] for discounting will lead to a declining discount rate.[64]

In the descriptive setting adopted by the IWG (2010), economists have demonstrated that calculating the expected net present value of a project is equivalent to discounting at a declining certainty equivalent discount rate when (1) discount rates are uncertain, and (2) discount rates are positively correlated (Arrow et al., 2014 at 157). Real consumption interest rates are uncertain given that there are no multi-generation assets to reflect long-term discount rates and the real returns to all assets—including government bonds— are risky due to inflation and default risk (Gollier & Hammitt, 2014). Furthermore, recent empirical work analyzing U.S. government bonds demonstrates that they are positively correlated over time; this empirical work has estimated several declining discount rate schedules that the IWG can use (Cropper et al., 2014; 2014; Arrow et al., 2013; Arrow et al., 2014; Jouini and Napp, 2014; Freeman et al. 2015).

Currently when evaluating projects, the U.S. government applies the descriptive approach using constant rates of 3% and 7% based on the private rates of return on consumer savings and capital investments. As discussed previously, applying a capital discount rate to climate change costs and benefits is inappropriate (Newell, 2017). Instead, analysis should focus on the uncertainty underlying the future consumption discount rate (Newell, 2017). Past U.S. government analyses (IWG, 2010; IWG, 2013; IWG, 2016) modeled three consumption discount rates reflecting this uncertainty. If the U.S. government correctly returns its focus on multiple consumption discount rates, then the expected net present value argument given above implies that a declining discount rate is the appropriate way to perform discounting. As an alternative, given that the Ramsey discount rate approach is the appropriate methodology in intergenerational settings, the U.S. government could use a fixed, low discount rate as an approximation of the Ramsey equation following the recommendation of Marten et al. (2015); see our discussion on Martin et al. 2015). This is roughly IWG (2010)'s goal for using the constant 2.5% discount rate.

If the normative approach to discounting is used in the future (i.e., the current approach of IAMs), economists have demonstrated that an extended Ramsey rule[65] implies a declining discount rate when (1) the growth rate of per capita consumption is stochastic,[66] and (2) consumption shocks are positively correlated over time (or their mean or variances are uncertain) (Arrow et al., 2013; Arrow et al., 2014; Gollier & Hammitt, 2014; Cropper et al., 2014).[67] While a constant adjustment downwards (known as the precautionary effect[68]) can be theoretically correct when growth rates are independent and identically distributed (Cropper et al., 2014), empirical evidence supports the two above assumptions for the United States, thus implying a declining discount rate (Cropper et al., 2014; Arrow et al., 2014; IPCC, 2014).[69] We should further expect this positive correlation to strengthen over time due to the negative impact of climate change on consumption, as climate change causes an uncertain permanent reduction in consumption (Gollier, 2009).[70]

Several papers have estimated declining discount rate schedules for specific values of the pure rate of time preference and elasticity of marginal utility of consumption (e.g., Arrow et al., 2014), though recent work demonstrates that the precautionary effect increases and discount rates decrease further when catastrophic economic risks (such as the Great Depression and the 2008 housing crisis) are modeled (Gollier & Hammitt, 2014; Arrow et al., 2014). It should be noted that this decline in discount rates due to uncertainty in the global growth path is in addition to that resulting from a declining central growth path over time (Nordhaus, 2014; Marten, 2015).[71]

Additionally, a related literature has developed over the last decade demonstrating that normative uncertainty (i.e., heterogeneity) over the pure rate of time preference (δ)—a measure of impatience—also leads to a declining social discount rate (Arrow et al., 2014; Cropper et al., 2014; Freeman and Groom, 2016). Despite individuals differing in their pure rate of time preference (Gollier and Zeckhauser, 2005), an equilibrium (consumption) discount exists in the economy. In the context of IAMs, modelers aggregate social preferences (often measured using surveyed experts) by calibrating the preferences of a representative agent to this equilibrium (Millner and Heal, 2015; Freeman and Groom, 2016). The literature generally finds a declining social discount rate due to a declining collective pure rate of time preference (Gollier and Zeckhauser, 2005; Jouini et al., 2010; Jouini and Napp, 2014; Freeman and Groom, 2016).[72] The heterogeneity of preferences and the uncertainty surrounding economic growth hold simultaneously (Jouini et al., 2010; Jouini and Napp, 2014), leading to potentially two sources of declining discount rates in the normative context.

Declining Rates are Actionable and Time-Consistent

There are multiple declining discount rate schedules from which the U.S. government can choose, of which several are provided in Arrow et al. (2014) and Cropper et al. (2014). One possible declining interest rate schedule for consideration by the IWG is the one proposed by Weitzman (2001).[73] It is derived from a broad survey of top economists in context of climate change, and explicitly incorporates arguments around interest rate uncertainty.[74] Other declining discount rate schedule include Newell and Pizer (2003); Groom et al. (2007); Freeman et al. (2015). Many leading economists support the United States government adopting a declining discount rate schedule (Arrow et al., 2014; Cropper et al., 2014). Moreover, the United States would not be alone in using a declining discount rate. It is standard practice for the United Kingdom and French governments, among others (Gollier & Hammitt, 2014; Cropper et al., 2014). The U.K. schedule explicitly subtracts out an estimated time preference.[75] France's schedule is roughly similar to the United Kingdom's. Importantly, all of these discount rate schedules yield lower present values than the constant 2.5% discount rate employed by IWG (2010), suggesting that even the lowest discount rate evaluated by the IWG is too high.[76] The consensus of leading economists is that a declining discount rate schedule should be used, harmonious with the approach of other countries like the United Kingdom. Adopting such a schedule would likely increase the SCC substantially from the administration's 3% estimate, potentially up to two to three fold (Arrow et al., 2013; Arrow et al., 2014; Freeman et al., 2015).

A declining discount rate motived by discount rate or growth rate uncertainty avoids the time inconsistency problem that can arise if a declining pure rate of time preference (δ) is used. Circular A-4 cautions that "[u]sing the same discount rate across generations has the advantage of preventing time- inconsistency problems."[77] A time inconsistent decision is one where a decision maker changes his or her plan over time, solely because time has passed. For instance, consider a decision maker choosing whether to make an investment that involves an up-front payment followed by future benefits. A time consistent decision maker would invest in the project if it had a positive net-present value, and that decision would be the same whether it was made 10 years before investment or 1 year before investment. A time inconsistent decision maker might change his or her mind as the date of the investment arrived, despite no new information becoming available. Consider a decision maker who has a declining pure rate of time preference (δ) trying to decide whether to invest in a project that has large up-front costs followed by future benefits. Ten years prior to the date of investment, the decision maker will believe that this project is a relatively unattractive investment because both the benefits and costs would be discounted at a low rate. Closer to the date of investment, however, the costs would be relatively highly discounted, possibly leading to a reversal of the individual's decision. Again, the discount rate schedule is time consistent as long as δ is constant.

The arguments provided here for using a declining consumption discount rate are not subject to this time inconsistency critique. First, time inconsistency occurs if the decision maker has a declining pure rate of time preference, not due to a decreasing discount rate term structure.[78] Second, uncertainty about growth or the discount rate avoids time inconsistency because uncertainty is only resolved in the future, after investment decisions have already been made. As the NAS (2017) notes, "One objection frequently made to the use of a declining discount rate is that it may lead to problems of time inconsistency….This apparent inconsistency is not in fact inconsistent….At present, no one knows what the distribution of future growth rates…will be; it may be different or the same as the distribution in 2015. Even if it turns out to be the same as the distribution in 2015, that realization is new information that was not available in 2015."[79]

We should note that time-inconsistency is not a reason to ignore heterogeneity (i.e., normative uncertainty) over the pure rate of time preference (δ). If the efficient declining discount rate schedule is time-inconsistent, the appropriate solution is to select the best time-consistent policy. Millner and Heal (2014) do just this by demonstrating that a voting procedure – whereby the median voter determines the collective preference – is: (1) time consistent, (2) welfare enhancing relative to the non-commitment, time-inconsistent approach, and (3) preferred by a majority of agents relative to all other time-consistent plans. Due to the right skewed distribution of the pure rate of time preference and the social discount rate as shown in all previous surveys (Weitzman, 2001; Drupp et al., 2015; Howard and Sylvan, 2015), the median is less than the mean social discount rate (and pure rate of time preference); the mean social discount rate is what holds in the very short-run under various aggregation methods, such as Weitzman (2001) and Freeman and Groom (2015). Combining an uncertain growth rate and heterogeneous preference together implies a declining discount rate starting at a lower value in the short-run. In addition to the reasons discussed earlier in the comments, this is another reason to exclude a discount rate as high as 7%.

There is an economic consensus on the appropriateness of employing a consumption discount rate (and the inappropriateness of a capital discount rate) in the context of climate change

There is a strong consensus among economists that it is theoretically correct to use consumption discount rates in the intergenerational setting of climate change, such as in the calculation of the SCC. Similarly, there is a strong consensus that a capital discount rate is inappropriate according to "good economics" (Newell, 2017).[80] This consensus holds across panels of experts on the social cost of carbon (NAS, 2017); surveys of experts on climate change and discount rates (Weitzman, 2001; Drupp et al., 2015; Howard and Sylvan, 2015; and Pindyck, 2016); the three most commonly cited IAMs employed in calculating the federal SCC; and the government's own analysis (IWG, 2010; CEA, 2017). For more analysis of this issue, see the discussion in the main body our Comments on the inappropriateness of using a discount rate premised on the return to capital in intergenerational settings.

56 Due to a slowing of global growth, DICE-2010 implies a declining discount rate schedule of 5.1% in 2015, 3.9% from 2015 to 2050; 2.9% from 2055 to 2100; 2.2% from 2105 to 2200, and 1.9% from 2205 to 2300. This would be a steeper decline if Nordhaus accounted for the positive and normative uncertainty underlying the SDR.

57 Due to a slowing of global growth, DICE-2016 implies a declining discount rate schedule of 5.1% in 2015, 4.7% from 2015 to 2050; 4.1% from 2055 to 2100; 3.1% from 2105 to 2200, and 2.5% from 2205 to 2300.

58 According to the World Bank, the average global and United States per capita growth rates were 1.7% and 1.9%, respectively.

59 Arrow et al. (2014) at 160-161 states that "We have argued that theory provides compelling arguments for using a declining certainty-equivalent discount rate," and concludes the paper by stating "Establishing a procedure for estimating a [declining discount rate] for project analysis would be an improvement over the OMB's current practice of recommending fixed discount rates that are rarely updated."

60 Karp (2005) states that mathematical "intuition for this result is that as [time] increases, smaller values of r in the support of the distribution are relatively more important in determining the expectation of e−rt" where r is the constant discount rate." Or as Hepburn et al. (2003) puts it, "The intuition behind this idea is that scenarios with a higher discount rate are given less weight as time passes, precisely because their discount factor is falling more rapidly" over time.

61 This argument was first developed in Weitzman (1998) and Weitzman (2001).

62 *See, e.g.,* Gollier (2009).

63 The Ramsey discount rate equation for the social discount rate is $r = \delta + \eta * g$ where r is the social discount rate, δ is the pure rate of time preference, η is the aversion to inter-generational inequality, and g is the growth rate of per capita consumption. For the original development, *see*, Ramsey, F. P. (1928). A Mathematical Theory of Saving. *The Economic Journal*, *38*(152).

64 Higher growth rates lead to higher discounting of the future in the Ramsey model because growth will make future generations wealthier. If marginal utility of consumption declines in consumption, then, one should more heavily discount consumption gains by wealthier generations. Thus, if growth rates decline over time, then the rate at which the future is discounted should also decline. *See*, *e.g.,* Arrow et al. (2014) at 148. It is standard in IAMs to assume that the growth rate of consumption will fall over time. *See*, *e.g.,* Nordhaus (2017) at 1519, "Growth in global per capita output over the 1980–2015 period was 2.2% per year. Growth in global per capita output from 2015 to 2050 is projected at 2.1% per year, whereas that to 2100 is projected at 1.9% per year." Similarly, Hope (2011) at 22 assumes that growth will decline. For instance, in the U.S., growth is 1.9% per year in 2008 and declines to 1.7% per year by 2040. Using data provided by Dr. David Anthoff (one of the founders of FUND), FUND assumes that the global growth rate was 1.8% per year from 1980–2015 period, 1.4% per year from 2015 to 2050 and 2015 to 2100, and then dropping to 1.0% from 2100 to 2200 and then 0.7% from 2200 to 2300.

65 If the future growth of consumption is uncertainty with mean μ and variance σ^2, an extended Ramsey equation $r = \delta + \eta * \mu - 0.5\eta^2\sigma^2$ applies where r is the social discount rate, δ is the pure rate of time preference, η is the aversion to inter-generational inequality, and g is the growth rate of per capita consumption. Gollier (2012, Chapter 3) shows that we can rewrite the extended discount rate as $r = \delta + \eta * g - 0.5\eta(\eta + 1)\sigma^2$ where g is the growth rate of expected consumption and $\eta + 1$ is prudence.

66 The IWG assumption of five possible socio-economic scenarios implies an uncertain growth path.

67 The intuition of this result requires us to recognize that the social planner is prudent in these models (i.e., saves more when faces riskier income). When there is a positive correlation between growth rates in per capita consumption, the representative agent faces more cumulative risk over time with respect to the "duration of the time spent in the bad state." (Gollier et al., 2008). In other words, "the existence of a positive correlation in the changes in consumption tends to magnify the long-term risk compared to short-term risks. This induces the prudent representative agent to purchase more zero-coupon bonds with a long maturity, thereby reducing the equilibrium long-term rate." (Gollier, 2007). Mathematically, the intuition is that under prudence, the third term in the extended Ramsey equation (*see* footnote 323) is negative, and a "positive [first-degree stochastic] correlation in changes in consumption raises the riskiness of consumption at date T, without changing its expected value. Under prudence,

this reduces the interest rate associated to maturity T" (Gollier et al., 2007) by "increasing the strength of the precautionary effect" in the extended Ramsey equation (Arrow et al., 2014; Cropper et al., 2014).
68 The precautionary effect measures aversion to future "wiggles" in consumption (i.e., preference for consumption smoothing) (Traeger, 2014).
69 Essentially, the precautionary effect increases over time when shocks to the growth rate are positively correlated, implying that future societies require higher returns to face the additional uncertainty (Cropper et al., 2014; Arrow et al., 2014; IPCC, 2014).
70 Due to the deep uncertainty characterizing future climate damages, some analysts argue that the stochastic processes underlying the long-run consumption growth path cannot be econometrically estimated (Weitzman, 2007; Gollier, 2012). In other words, economic damages, and thus future economic growth, are ambiguous. Agents must then form subjectivity probabilities, which may be better interpreted as a belief (Cropper et al., 2014). Again, theory shows that ambiguity leads to a declining discount rate schedule by Jensen's inequality (Cropper et al., 2014).
71 A common assumption in IAMs is that global growth will slow over time leading to a declining discount rate schedule over time; *see* footnote 7. Uncertainty over future consumption growth and heterogeneous preferences (discussed below) would lead to a more rapid decline in the social discount rate.
72 The intuition for declining discount rates due to heterogeneous pure rates of time preference is laid out in Gollier and Zeckhauser (2005). In equilibrium, the least patient individuals trade future consumption to the most patient individuals for current consumption, subject to the relative value of their tolerance for consumption fluctuations. Thus, while public policies in the near term mostly impact the most impatient individuals (i.e., the individuals with the most consumption in the near term), long-run public policies in the distant future are mostly going to impact the most patient individuals (i.e., the individuals with the most consumption in the long-run).
73 Weitzman (2001)'s schedule is as follows: 4% for 1-5 years; 3% for 6-25 years; 2% for 26-75 years; 1% for 76-300 years; and 0% for 300+ years.
74 Freeman and Groom (2014) demonstrate that this schedule only holds if the heterogeneous responses to the survey were due to differing ethical interpretations of the corresponding discount rate question. A recent survey by Drupp et al. (2015) – which includes Freeman and Groom as co-authors – supports the Weitzman (2001) assumption.
75 The U.K. declining discount rate schedule that subtracts out a time preference value is as follows (Lowe, 2008): 3.00% for 0- 30 years; 2.57% for 31-75 years; 2.14% for 76-125 years; 1.71% for 126- 200 years; 1.29% for 201-300 years; and 0.86% for 301+ years.
76 Using the IWG's 2010 SCC model, Johnson and Hope (2012) find that the U.K. and Weitzman schedules yield SCCs of $55 and $175 per ton of CO_2, respectively, compared to $35 at a 2.5% discount rate. Because the 2.5% discount rate was included by the IWG (2010) to proxy for a declining discount rate, this result indicates that constant discount rate equivalents may be insufficient to address declining discount rates.
77 *Circular A-4* at 35.
78 Gollier (2012) states "It is often suggested in the literature that economic agents are time inconsistent if the term structure of the discount rate is decreasing. This is not the case. What is crucial for time consistency is the constancy of the rate of impatience, which is a cornerstone of the classic analysis presented in this book. We have seen that this assumption is compatible with a declining monetary discount rate."
79 National Academies of Sciences, Engineering, and Medicine, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide 182 (2017).
80 The former co-chair of the National Academy of Sciences' Committee on Assessing Approaches to Updating the Social Cost of Carbon – Richard Newell (2017) – states that "[t]hough the addition of an estimate calculated using a 7 percent discount rate is consistent with past regulatory guidance under OMB Circular A-4, there are good reasons to think that such a high discount rate is inappropriate for use in estimating the SCC…It is clearly inappropriate, therefore, to use such modeling results with OMB's 7 percent discount rate, which is intended to represent the historical before-tax return on private capital…This is a case where unconsidered adherence to the letter of OMB's simplified discounting approach yields results that are inconsistent with and ungrounded from good economics."

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Comment Excerpt Number: 200

Comment Excerpt:

A. EPA Underestimated Costs Caused by Mercury's Impacts on Children.

Mercury is well-known neurotoxin with no safe level of exposure that disproportionately impacts children. EPA acknowledges that "[f]etuses, infants, and children are particularly susceptible to impaired neurological development from methylmercury exposure (ATSDR, 1999; Evers et al., 2011)."[767]

EPA underestimated the foregone benefits associated with EPA's proposed option to allow increased amounts of mercury discharges compared to the baseline. EPA acknowledges that it quantified "only a subset of the potential health benefits (or foregone benefits) that are expected to result from the regulatory options."[768]

EPA underestimated economic costs associated with increased emissions of mercury in Options 2, 3 and 4 by assuming a low potency of IQ effect. EPA assumed that a 1 ppm increase in maternal hair mercury would result in a 0.18 IQ loss in the child, and acknowledged that this assumption was uncertain and may under- (or over-) estimate IQ impacts of mercury exposure.[769] In fact, EPA underestimated IQ effect and should have assumed a higher IQ loss. A recent European publication estimated that mercury has a 2.5 times stronger effect on IQ.[770] This study relied on an oft-cited 2006 study from the New York Academy of Sciences, and used a linear function that assumes that each doubling of exposure above the background causes a deficit of 1.5 IQ points.[771]

EPA also underestimated economic costs by not considering the effect of exposure to mercury after birth. Mercury can damage children in multiple ways that EPA did not assess.

[767] Proposed EA at A-5.
[768] Proposed BCA at 2-7.
[769] Id. at 5-15.
[770] Martine Bellanger et al., Economic benefits of methylmercury exposure control in Europe: Monetary value of neurotoxicity prevention. Environ Health 12, 3 (2013), https://ehjournal.biomedcentral.com/articles/10.1186/1476-069X-12-3 (attached).
[771] Id. (citing Trasande L, Schechter C, Haynes KA, Landrigan PJ: Applying cost analyses to drive policy that protects children: mercury as a case study. Ann. N. Y. Acad Sci. 2006, 1076: 911-923).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 201

Comment Excerpt:

B. EPA Failed to Assess All Impacts of Lead Exposure.

EPA acknowledges that there is no safe level of exposure to lead and that lead exposure is particularly devastating to children. EPA also acknowledges that its proposal would increase human exposure to lead. Because lead exposure has a disproportionate impact on children, the increased exposure due the proposed rule will unquestionably have a disproportionate impact on our nation's children. Yet EPA does not address the disproportionate impact.

Lead poisoning poses an enormous public health concern. The toxicity of lead in children has a greater impact than in adults because "their tissues, internal as well as external, are softer than in adults" and because their organs are developing.[772] And "[i]nfants and young children are especially sensitive to even low levels of lead."[773] The absorption of lead occurs more quickly in children than adults.[774] EPA acknowledges the devastating impacts that exposure to lead has on children:

Human exposure to high concentrations of lead in drinking water (and other exposure pathways) can result in adverse impacts to almost every organ and body system. Lead impacts include neurological effects, with long-term exposure resulting in children (e.g., decreased cognitive function, IQ loss, altered behavior and mood, and weakness in fingers, wrists, or ankles), renal damage and reduced renal function, cardiovascular impacts (e.g., increased blood pressure), reproductive impacts, and developmental impacts. Developmental impacts include premature births and decreased child growth (ATSDR, 2019b).[775]

EPA, however, did not evaluate all the impacts of lead on children. EPA evaluated non-cancer and cancer human health impacts through the IRW Human Health Module and oral reference doses (RfDs). EPA states that it did not develop RfDs for lead because "adverse health effects 'may occur at blood levels so low as to be essentially without a threshold.'"[776] Yet EPA also acknowledges "Option 2 increases the annual loadings of lead to the environment by 693 pounds compared to baseline."[777]

To its credit, EPA did quantify the IQ losses from lead exposure among preschool children. However, EPA acknowledges that it monetized only a subset of the potential foregone health benefits, and did not consider, among other things, "low birth weight and neonatal mortality from in-utero exposure to lead, decreased postnatal growth in children ages one to 16, delayed puberty, immunological effects, decreased hearing and motor function (U.S. EPA, 2009a; 2019h)."[778] EPA also did not consider the effects of children's exposure to lead after age seven.

[772] Ab Latif Wani et al, Lead Toxicity: a review, Interdiscip Toxic. 2015 Jun; 8(2): 55-64, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4961898/ (attached).
[773] Id.
[774] Id.
[775] Proposed EA at A-4.
[776] Id. at 4-11, n.29.
[777] Id. at 4-11.
[778] Proposed BCA at 2-7.

42 Executive Orders

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.

Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 29

Comment Excerpt:

Selenium pollution is concerning for many reasons, not the least of which is environmental justice. In 2016, the United States Commission on Civil Rights found the percentage of minorities and low income individuals living near coal ash sites is "disproportionately high," when compared with national averages.[46] It further found that "racial minorities and low income communities are disproportionately affected by the siting of waste disposal facilities and often lack political and financial clout to properly bargain with polluters when fighting a decision or seeking redress."[47] In North Carolina, the Belews Creek site is in Walnut Cove, a community that is 74 percent people of color. The report published by the United States Commission on Civil Rights documents the serious environmental justice concerns in this community, including selenium pollution from the plant that killed 19 of 20 fish species in Belews Lake.[48] The community around Duke Energy's North Carolina Cliffside/Rogers plant is also an environmental justice community. Pollution at the Cliffside site disproportionately burdens lower-income families. Selenium contamination jeopardizes the fish in the Broad River that some subsistence fishermen may rely upon to feed their families. Please see the attached letter from the Southern Environmental Law Center and partnering community groups to the NC DEQ Environmental Justice and Equity Board, dated January 30, 2019, for more information on environmental justice concerns related to coal ash sites in North Carolina.[49]

[46] U.S. Commission on Civil Rights, Environmental Justice: Examining the Environmental Protection Agency's Compliance and Enforcement of Title VI and Executive Order 12,898 at 4 (Sept. 2016), available at https://www.usccr.gov/pubs/2016/Statutory_Enforcement_Report2016.pdf (the "Commission Report") (Attachment 7).
[47] Id. at 4, 6.
[48] Id. at 194.
[49] Letter from Southern Environmental Law Center to NC DEQ Environmental Justice and Equity Board, Jan. 30, 2019 (Attachment 8) ("SELC EJ Letter").

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 88

Comment Excerpt:

VII. ENVIRONMENTAL JUSTICE

The concerns presented in this letter are worsened by the fact that pollution from coalfired power plants disproportionately burdens communities of color, low-income families, and indigenous people. Coal ash pollution is a serious environmental justice problem nationwide.

In 2016, the United States Commission on Civil Rights (the "Commission") issued a report specifically examining coal ash and environmental justice.[293] The Commission found the percentage of minorities and low income individuals living near coal ash is "disproportionately high," when compared with national averages.[294] It further found that "racial minorities and low income communities are disproportionately affected by the siting of waste disposal facilities and often lack political and financial clout to properly bargain with polluters when fighting a decision or seeking redress."[295] Among other sources, the Commission based these findings on statistics from a peer-reviewed study that shows polluters "tend to site facilities that can negatively impact human health in these communities because they lack the political clout and resources necessary to fight siting decisions."[296]

This is especially true in the Southeast. The Commission cites a 1983 report ordered by Congress from the United States General Accountability Office, which discovered that threequarters of hazardous waste sites in eight states in the Southeast were located in primarily poor and African American or Latino communities.[297] A 1994 report by the United Church of Christ Commission for Racial Justice revealed the situation was only getting worse—the number of people of color living near hazardous waste facilities increased by six percent between 1980 and 1993, so that people of color were 47 percent more likely than whites to live near hazardous waste.[298] The Commission notes that more than 20 years since this report, "its findings may still hold relevance today as environmental issues still impact minorities and low-income communities."[299]

Coal ash contamination has harmed low-income, minority, and indigenous communities in our region[300] in many ways—including, for example, polluting the groundwater that families and small farmers rely upon in rural areas,[301] raising serious worker safety issues for low-wage laborers hired to clean-up coal ash spills,[302] and siting landfills in environmental justice communities.[303]

[293] Commission Report, Attachment 7, at 3 (The Commission defines environmental justice as a civil right, meaning "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income,with respect to the development, implementation, and enforcement of environmental laws, regulations and policies.").

[294] Id. at 4.
[295] Id. at 4, 6.
[296] Id. at 6.
[297] Id. at 7.
[298] Id. at 8.
[299] Id.
[300] See SELC EJ Letter, Attachment 8 (discussion of environmental justice impacts in North Carolina). In February 2019, the NC DEQ Environmental Justice and Equity Board agreed and recommended to NC DEQ that it require full excavation at all remaining coal ash sites in North Carolina. See letter from Dr. Marian Johnson-Thompson, Vice Chair, NC DEQ Environmental Justice and Equity Board, to Michael Regan, Secretary, NC DEQ (Feb. 15, 2019) (Attachment 104). On April 1, 2019, NC DEQ ordered Duke Energy to fully excavate all six coal ash sites at issue. See, e.g., NC DEQ, DEQ Coal Combustion Residuals Surface Impoundment Closure Determination, Belews Creek Steam Station (April 1, 2019), available at https://files.nc.gov/ncdeq/Coal%20Ash/2019-aprildecision/belews/BelewsCreek_FINAL_ImpoundmentClosureDeterminationReport_20190401.pdf (Attachment 105).
[301] See letter from Southern Environmental Law Center to Georgia Environmental Protection Division, 17 (Aug. 5, 2019) (Attachment 106).
[302] In November 2018, a jury found that TVA's contractor for the Kingston clean-up failed to adequately protect workers from exposure to coal ash contamination. *See* Jamie Satterfield, Jury: Jacobs Engineering endangered Kingston disaster clean-up workers, KNOX NEWS (Nov. 7, 2018), available at https://www.knoxnews.com/story/news/crime/2018/11/07/verdict-reached-favor-sickened-workers-coal-ash-cleanup-lawsuit/1917514002/ (Attachment 107). Forty-four Kingston disaster workers have died from illnesses they

assert in the lawsuit were caused by coal ash exposure, and more than 400 are sick, according to an ongoing tally from court records by Knox News. See Jamie Satterfield, Activists honor Kingston coal ash cleanup workers and announce upcoming protest against Jacobs, KNOX NEWS (Nov. 17, 2019), https://www.knoxnews.com/story/news/local/tennessee/tvacoalash/2019/11/18/kingston-coal-ash-cleanup-workershonored-jobs-with-justice/4205940002/ (Attachment 108).

[303] In the aftermath of the Kingston coal ash failure, TVA transported ash to the Arrowhead Landfill in Perry County, Alabama, a landfill in an environmental justice community that had already been subjected to repeated violations of pollution laws. See Kristen Lombardi, Welcome to Uniontown: Arrowhead Landfill Battle a Modern Civil Rights Struggle, NBC NEWS (Aug. 5, 2015), http://www.nbcnews.com/news/nbcblk/epa-environmentalinjustice-uniontown-n402836 (Attachment 109). In September 2016, the United States Commission on Civil Rights issued a report finding that the decision to move coal ash to the Arrowhead Landfill was primarily based on technical considerations, including cost, and did not properly take into account environmental justice concerns. See Commission Report, Attachment 7, at 65-69.

Commenter Name: Megan Kimball
Commenter Affiliation: Southern Environmental Law Center et al.
Document Control Number: EPA-HQ-OW-2009-0819-8465-A1
Comment Excerpt Number: 89

Comment Excerpt:

EPA's EJSCREEN tool demonstrates the significant environmental justice issues near power plants in the Southeast. For example, in South Carolina, three plants are located in majority-minority and low-income communities, and those communities face environmental risks that far exceed the national averages. These three communities rank in the top third percentile for all eleven of EPA's environmental justice indices, with the Cross and Wateree plants ranking in the 99th percentile for EPA's wastewater discharge indicator and the Winyah plant ranking in the 96th percentile for that indicator.[304]

Meanwhile, Eden, North Carolina and Danville, Virginia bear the brunt of the harm from bromide discharged by Duke Energy from Belews Creek, as explained above, and both of these communities face significant environmental justice concerns. Danville ranks between the 78th to 97th percentile for all eleven of EPA's environmental justice indices, and Eden comes close, ranging between the 65th and 95th percentiles.[305] Both are in the top five percent for the wastewater discharge indicator (Danville—97%; Eden—95%).

These five places are only examples of a larger problem. The same analysis could be performed for plants across the Southeast and the nation, and we would find similar patterns confirming what the U.S. Commission on Human Rights found in 2016: pollution from power plants disproportionately harms minority, low-income, and indigenous communities.

EPA's proposal to base effluent limitations on less-than-best available technology only exacerbates the harm to these communities. Instead of protecting the environment and public health, EPA prioritizes minimal cost-savings spread across the entire industry at the expense of the surrounding communities directly impacted by water pollution from particular facilities. Instead of requiring utilities to internalize the cost of harm from their industry, EPA proposes to shift this burden to surrounding communities that are least able to bear it, at significant expense to the public, including precious local tax dollars, while placing at risk natural resources and human health.

For example, EPA proposes no limits on bromide discharges, shifting the cost of this pollution to downstream communities. EPA estimates this proposal would result in more bladder cancer cases and deaths[306] and cost the public $120 million in lost benefits,[307] but it would save the industry $121 million.[308] And these are only the costs EPA took into account. In its proposal, EPA fails to account for other costs to the public.

As we have seen in Danville and Eden, in order to address the carcinogenic trihalomethanes in drinking water resulting from bromide discharges, local governments will need to invest in costly drinking water treatment technology, diverting resources from other pressing needs in the community. Some municipalities may not be able to afford a fix; others that can afford it may be unsuccessful, as has been the case in Danville and Eden, described above. Many residents in these communities have no choice but to continue to drink the water from their taps and face the cancer risk; they may not be able to afford expensive reverse osmosis treatment systems or bottled water.

[304] EJSCREEN Report for five-mile radius around Cross Station, Cross Station Rd, Pineville, SC 29468, https://ejscreen.epa.gov/mapper/ (last accessed Jan. 20, 2020) (Attachment 110); EJSCREEN Report for five-mile radius around Wateree Station, 142 Wateree Station Rd, Eastover, SC 29044, https://ejscreen.epa.gov/mapper/ (last accessed Jan. 20, 2020) (Attachment 111); EJSCREEN Report for five-mile radius around Winyah Station, 661 Steam Plant Dr, Georgetown, SC 29440, https://ejscreen.epa.gov/mapper/ (last accessed Jan. 20, 2020) (Attachment 112).
[305] EJSCREEN Report for three-mile radius around Danville, VA, https://ejscreen.epa.gov/mapper/ (last accessed Jan. 20, 2020) (Attachment 113); EJSCREEN Report for three-mile radius around Eden, NC, https://ejscreen.epa.gov/mapper/ (last accessed Jan. 20, 2020) (Attachment 114).
[306] EPA, Benefit & Cost Analysis, Table 4-7 (estimating Option 2 would result in $37 million in benefits per year, whereas Option 4 would result in $84 million—more than twice as much).
[307] 84 Fed. Reg. 64,660 (Option 2 would result in $68.5 million total annualized benefits at a three percent discount rate, whereas Option 4 would result in $188 million in benefits.)
[308] 84 Fed. Reg. 64,645 (Option 2 would save industry $147 million, and Option 4 would save industry $26 million).

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 3

Comment Excerpt:

3. EPA's assessment of the Proposed Rule's cost-benefit analysis is fundamentally flawed.

Commenter Name: Bethany Davis Noll
Commenter Affiliation: Institute for Policy Integrity, New York University School of Law
Document Control Number: EPA-HQ-OW-2009-0819-8329-A1
Comment Excerpt Number: 6

Comment Excerpt:

A. EPA Illegally Focuses on Cost While Neglecting Other Statutorily Mandatory Factors to Set the BAT

To justify its changes to the 2015 Rule, the agency cites a relative decrease in "social costs."[48] This term is misleading; although EPA claims "social costs" reflect the Proposed Rule's downsides "from the viewpoint of society as a whole, rather than the viewpoint of regulated facilities," the term in fact reflects only industrial compliance costs, and excludes health or environmental costs associated with loosening the effluent limitations.[49] The Supreme Court has made clear that "'cost' includes more than the expense of complying with regulations; any disadvantage could be termed a cost."50 Such disadvantages include "harms that regulation might do to human health or the environment."[51] Because EPA's use of the term "social costs" is misleading, this comment refers to such costs as "compliance costs." The agency should do so as well. Of the four regulatory options EPA evaluated, the agency proposes to choose the option with the lowest compliance costs for industry.[52]

For each of its proposed regulatory changes, EPA cites cost as the motivating factor but then fails to consider cost relative to the health and environmental harms associated with each change. This failure constitutes a violation of the Clean Water Act. Furthermore, courts have repeatedly rejected such lopsided analysis, which arbitrarily focuses on some costs while failing to consider forgone benefits.[53] The Administrative Procedure Act requires "balanced consideration" of the "impact[s] of any [regulatory] action,"[54] which EPA violates by "put[ting] a thumb on the scale"[55] and fixating on compliance cost while neglecting health and environmental effects.

48 See Proposed Rule, 84 Fed. Reg. at 64,645 (referring to an annualized decrease in social costs of $136.3 million using a 3% discount rate and $166.2 million using a 7% discount rate).
49 EPA's definition of "social costs" seems inconsistent throughout the Proposed Rule. For example, in the Proposed Rule itself, EPA says that "[s]ocial costs are the costs of the proposed rule from the viewpoint of society as a whole, rather than the viewpoint of regulated facilities," which would presumably include health and environmental harms caused by the Proposed Rule relative to the 2015 Rule. 84 Fed. Reg. at 64,645. But on the same page, EPA defines social costs as including only "costs incurred by private entities and the government." Id. Then EPA says "the only
category of costs used to calculate social costs are those pre-tax costs estimated for steam electric facilities." Id. Thus, EPA's "social costs" in fact narrowly refer to industry compliance costs and do not represent all costs "to society as a whole."
50 Michigan v. EPA, 135 S. Ct. 2699, 2707 (2015).
51 Id.; see also Competitive Enter. Inst. v. Nat'l Highway Traffic Safety Admin., 956 F.2d 321, 326–27 (D.C. Cir. 1992) (holding that the agency should have considered costs in the form of safety risks associated with the smaller size of more fuel-efficient cars).
52 EPA, REGULATORY IMPACT ANALYSIS FOR PROPOSED REVISIONS TO THE EFFLUENT LIMITATIONS GUIDELINES
AND STANDARDS FOR THE STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY 3-7 (2019) [hereinafter
RIA].
53 See, e.g., Bus. Roundtable v. SEC, 647 F.3d 1144, 1148-49 (D.C. Cir. 2011) (chastising agency for "inconsistently and opportunistically fram[ing] the costs and benefits of the rule [and] fail[ing] adequately to quantify the certain costs or to explain why those costs could not be quantified"); Pub. Citizen, Inc. v. Mineta, 340 F.3d 39, 58 (2d Cir. 2003) (holding that a rule "that does not explain why the costs saved were worth the benefits sacrificed" is arbitrary and capricious"); Make the Road New York v. McAleenan, No. 19-CV-2369 (KBJ), 2019 WL 4738070, at *36 (D.D.C. Sept. 27, 2019) (finding regulation irrational because DHS considered the upsides of

its regulation but not the environmental downside of flooding); California v. BLM, 277 F. Supp. 3d 1106, 1123 (N.D. Cal. 2017) (agencies impermissibly considered only "one side of the equation" by calculating benefits and ignoring costs).
54 Corrosion Proof Fittings v. EPA, 947 F.2d 1201, 1221 (5th Cir. 1991) (internal quotation marks omitted).
55 Ctr. for Biol. Diversity v. Nat'l Highway Traffic Safety Admin., 538 F.3d 1172, 1198 (9th Cir. 2008).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 159

Comment Excerpt:

XIII. THE PROPOSED RULE UNJUSTIFIABLY TRADES SMALL COST SAVINGS TO INDUSTRY FOR SIGNIFICANT LOSSES IN PUBLIC HEALTH AND ENVIRONMENTAL BENEFITS.

"EPA estimates that its proposed option (i.e., Option 2) will save $136.3 million per year in social costs and result in between $14.8 million and $68.5 million in benefits, using a three percent discount [rate]. . . ."[614] However, as explained in detail below and in the attached report prepared by Synapse Energy Economics,[615] EPA's Proposed BCA is deeply flawed and severely underestimates lost benefits under EPA's preferred regulatory option. In reality, EPA unjustifiably trades small cost savings to industry for significant losses in public health and environmental benefits.

[614] 84 Fed. Reg. at 64,622; see also Proposed BCA at ES-2 to ES-3.
[615] Synapse Energy Economics, Inc., Review of Benefit-Cost Analysis for the EPA's Proposed Revisions to the 2015 Steam Electric Effluent Limitations Guidelines (Jan. 21, 2020) ("2020 Synapse BCA Analysis") (attached).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 164

Comment Excerpt:

A. Structural Flaws in EPA's Analysis Conceal the True Costs of EPA's Proposed Action.

Structural flaws in EPA's Proposed BCA – including an improper baseline and a failure to clearly and transparently state costs and benefits associated with individual program components – obscure the true costs of EPA's proposed action and hinder public assessment of regulatory alternatives.

EPA's decision to effectively exempt[618] units either retiring or fuel switching by December 31, 2028 from compliance with the ELGs results in a significant loss of environmental benefits that should otherwise have been achieved under the 2015 ELG Rule. However, EPA did not calculate the pollution reductions that might have been achieved through pollution control upgrades at the subject facilities and therefore did not monetize the loss of such benefits within the Proposed BCA. Instead, EPA removed such facilities from consideration entirely[619] – essentially subsuming the lost benefits within an improper and artificial regulatory baseline.[620]

EPA also failed to adequately and transparently break out impacts from proposal components, partially obscuring the true drivers of Option costs and benefits. For example, a careful review of the Proposed BCA clarifies that EPA's claim that Option 2 will both increase benefits and lower costs stems entirely from the Agency's assumptions concerning participation in the proposed Voluntary Incentives Program. EPA projects that 18 plants will join the VIP under Option 2, with 90% of bromide reduction benefits deriving from just 6 plants.[621] Absent those bromide reductions, net benefits from Option 2 would decrease relative to a 2015 baseline.[622] Under Option 4, meanwhile, net benefits would increase both with and without VIP program bromide reduction benefits.[623] EPA's failure to transparently break out impacts from individual program components is inconsistent with BCA best practices and hinders the public's ability to thoroughly assess the merits of EPA's proposed action.[624]

[618] "Under all four options, boilers retiring by December 31, 2028, would be subcategorized, and for this subcategory BAT limitations would be set equal to BPT limitations for TSS based on the use of surface impoundments." 84 Fed. Reg. at 64,630 (using substantially similar language for both the FGD wastewater and BA transport water wastestreams). See also Section X.B – Retirement Subcategory.
[619] "The EPA removed coal-fired generating units that will retire or convert fuel type prior to December 31, 2028, from the analyses supporting this proposed rule . . . ." Proposed TDD at 3-4.
[620] See 2020 Synapse BCA Analysis at 8, 11; see generally Section IV – Alternatives.
[621] 2020 Synapse BCA Analysis at 20.
[622] Id. at 19.
[623] Id.
[624] Id. at 13, 21

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 175

Comment Excerpt:

In summary, EPA's dramatically incomplete accounting of health and other benefits renders the agency's Proposed BCA fatally flawed. As EPA itself acknowledges, "the total monetary value of changes in human health effects included in this analysis represent only a subset of the potential health benefits (or forgone benefits) that are expected to result from the regulatory options."[661] Since EPA's evaluation of benefits is profoundly incomplete, its comparison of benefits to costs is meaningless, and the Proposed BCA is an invalid basis for any Agency decision-making.

[661] Proposed BCA at 2-7.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 193

Comment Excerpt:

XV. THE PROPOSED RULE VIOLATES EXECUTIVE ORDER 12898 ON ENVIRONMENTAL JUSTICE.

Executive Order ("E.O.") 12898 requires that "each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States and its territories and possessions, the District of Columbia, the Commonwealth of Puerto Rico, and the Commonwealth of the Mariana Islands." This obligation was recently affirmed in *Standing Rock Sioux Tribe v. U.S. Army Corps of Engineers*,[747] and has been applied by the U.S. Environmental Appeals Board. Specifically, "[t]he purpose of an environmental justice analysis is to determine whether a project will have a disproportionately adverse effect on minority and low income populations."[748] This proposed rule violates E.O. 12898 by failing to take all lawful and practicable steps to identify and address the disproportionate and adverse impacts of coal ash wastewater on communities of color and low-income communities.

A. EPA Failed To Meaningfully Evaluate All Regulatory Options To Determine Whether There Are Differing Effects On Communities Of Color And Low-Income Communities.

In its E.O. 12898 review, EPA did not identify and analyze the different impacts that the relevant regulatory options would have on environmental justice communities. The four options and three bromide-specific sub-options proposed in this rulemaking lead to different pollutant-loadings and create different outcomes in protections of health and the environment for environmental justice communities. Additionally, as elaborated in Sections IV - Alternatives and IX - Bromide of these comments, these options do not represent a meaningful comparison of potential actions by the Agency. As part of its E.O.12898 review, EPA must not only identify the populations likely to be impacted but also identify and compare the impacts that will result from changes in pollutant loadings and other health and environmental outcomes from the options. At a minimum, EPA should identify and compare the impacts of all four options and three bromide-specific sub-options, as well as the impacts of no action.

[747] 255 F. Supp. 3d 101, 141 (D.D.C. 2017) (cursory environmental justice analysis insufficient to discharge environmental justice responsibilities under NEPA).
[748] Id.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 194

Comment Excerpt:

1. EPA failed to meaningfully analyze the effects of anticipated changes in pollutant loadings from the proposed regulatory options.

EPA's E.O. 12898 review fails to meaningfully identify how differences in the anticipated changes in pollutant loadings from the proposed regulatory options would impact environmental justice communities. Chapter 14 of the Proposed BCA includes just one table that compares the four options as they pertain to children's exposure to lead and infants' exposure to mercury from fish consumption, with no meaningful discussion of the table's contents and what implications it had for environmental justice communities.[749] EPA's E.O. 12898 review concludes with the wholly inconclusive statement: "Because communities at the census block, county, and tribal area levels are poorer and more minority than state averages, the regulatory options could benefit or harm populations with [environmental justice] concerns depending on the direction of changes in pollutant loadings for the regulatory options and the resulting change in potential exposure."[750]

Therefore, in its E.O. 12898 review, EPA appears to have concluded that proposed rule may or may not have disproportionate impacts on environmental justice populations, depending how the rule impacts coal ash wastewater pollution levels. However, EPA does not go any further to clearly identify the pollutant loadings impacts anticipated by the proposed regulatory options and identify whether these may disproportionately impact environmental justice populations. Without a more detailed review that identifies and applies the anticipated changes in pollutant loadings, the Agency's E.O. 12898 review is meaningless. It provides no useful information on how the Agency's preferred regulatory option will actually impact environmental justice communities or on how the preferred regulatory option compares to other regulatory options in terms of environmental justice impacts.

[749] Proposed BCA at 14-9, tbl. 14-7.
[750] Id. at 14-13.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 195

Comment Excerpt:

2. EPA failed to account for the possibility that the proposed VIP will not result in significant pollution reduction.

EPA appears to approach its E.O. 12898 review with the assumption that there will be net environmental and public health benefits from the proposed rule. For example, the Agency describes its review as examining "whether the benefits from the regulatory options may be differently distributed among population subgroups in the affected areas."[751] EPA's claims that the proposed rule will lead to reductions in pollutant loadings are based largely on the Agency's projection that the proposed voluntary incentive program ("VIP") will lead to significant reductions. As elaborated in Section VIII - VIP of these comments, EPA has provided no evidence to support the Agency's assumption the proposed VIP will be widely adopted enough to result in significant reductions of pollution.

Due to EPA's failure to fully and transparently factor in anticipated changes in pollutant loadings in its E.O. 12898 analysis, it is difficult to determine how EPA's assumptions regarding the success of the proposed VIP impact the Agency's conclusions on the impacts of the proposed rule on environmental justice populations. However, it appears that the Agency's E.O. review failed to take into account the likely possibility that the VIP program will not have as high of a level of participating as EPA has predicted. EPA's E.O. 12898 review should include an analysis that takes into account anticipated pollutant loadings that will result if there is little to no participation in the proposed VIP.

[751] Id. at 14-1.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 196

Comment Excerpt:

3. *EPA failed to identify the disparate impact on communities of color and low-income populations of regulatory options that allow the continued use of coal ash surface impoundments.*

EPA's proposed low-utilization subcategory would allow coal units that generate less than 876,000 MWh per year to continue using surface impoundments to treat bottom ash wastewater.[752] Additionally, EPA proposes to allow coal plants that plan to retire by 2028 to continue using surface impoundments to treat both FGD wastewater and bottom ash wastewater, with no numeric limitations on any toxic pollutants. EPA's E.O. 12898 review is insufficient because it fails to identify the communities of color and low-income communities that would be impacted by the continued use of surface impoundments at these sites. This omission is particularly glaring in light of the ample evidence previously provided to EPA demonstrating that low-income communities and communities of color are disproportionately impacted by coal ash surface impoundments.

In the Regulatory Impact Analysis for the 2015 Coal Combustion Residuals rule, EPA estimated that at least 1.5 million people of color live in the "catchment areas" of coal ash surface impoundments at 277 power plants throughout the United States.[753] In catchment areas[754] downstream of coal ash impoundments, residents are threatened by leaks, discharges and spills of toxic chemicals, as well as potentially deadly catastrophic failures. EPA found that the minority population in catchment areas is higher than both national and state averages.[755]

EPA also estimates nearly 900,000 low-income residents live in catchment areas, which is also higher than state and national averages. In fact, more than 60% of the power plants operating coal ash impoundments are located in catchment areas where the percentage of residents who live below the Federal Poverty Level exceeds statewide percentages.[756] In other words, the population living below the poverty level near these coal ash impoundments is about 40% larger than would be expected based on statewide averages, and the minority population is approximately 20% greater. Almost 70% of ash ponds in the United States are in areas where household income is lower than the national median.[757]

Of the 181 ZIP codes nationally that contain coal ash ponds, 118 (65.19%) have above-average percentages of low-income families.[758] Given the serious health threats posed by coal ash, it is particularly troublesome that coal ash impoundments are disproportionately located in low-income communities, where residents are more likely to rely on groundwater supplies and less likely to have access to medical insurance and healthcare. As the United States Civil Rights Commission noted, "[r]acial minorities and low income communities are disproportionately affected by the siting of waste disposal facilities and often lack political and financial clout to properly bargain with polluters when fighting a decision or seeking redress."[759]

The disparate health impacts from coal ash impoundments are not evenly distributed across the United States. Certain states face worse disproportionate impacts than others. For example, more than half of residents living near coal plants in New Mexico—and more than forty percent in Alabama, Arizona, Georgia, and Illinois—are non-white. Further, coal ash impoundments are more numerous in the southeastern United States, and the populations near the dumps tend to be poorer and less white.[760] In addition, in the absence of federal regulation of coal ash, state regulations created a patchwork of inadequate controls, with many states having no regulation of the disposal of coal ash, particularly of wet impoundments.[761]

[752] See Section X.D – Low Utilization.
[753] EPA, Regulatory Impact Analysis (RIA) for EPA's 2015 Coal Combustion Residuals (CCR) Final Rule, Docket ID No. EPA-HQ-RCRA-2009-0640-12034, at 8-10.
[754] EPA defines "catchment area" as the downstream area that receives surface water runoff and releases from CCR impoundments, and incurs risks from CCR impoundment discharges (e.g., unintentional overflows, structural failures, and intentional periodic discharges). Catchment areas are measured in terms of runoff travel time. This analysis considers populations in all catchments within 24 hours of downstream travel time from the plant under mean surface water flow conditions, to estimate populations potentially affected by impoundment failures. Id. at 8-9.
[755] Id. at 8-12.
[756] Id. at 8-12.
[757] U.S. Census Bureau, Census 2000 Summary File 3 (SF 3) - Sample Data, All 5-Digit ZIP Code Tabulation Areas (860), Table P53 "Median Household Income in 1999 (Dollars)".
[758] U.S. Census Bureau, Census 2000 Summary File 3 (SF 3) - Sample Data, All 5-Digit ZIP Code Tabulation Areas (860), Table P76 "Family Income in 1999" (downloaded June 23, 2009). "Low-income" defined as earning less than $20,000 annually. ZIP codes containing coal ash ponds compared to a national mean percent "low-income" of 12.61%, calculated based on the "Family Income in 1999" dataset; United States

Environmental Protection Agency (U.S. EPA). Database of coal combustion waste surface impoundments (2009). Information collected by EPA from industry responses to Information Collection Request letters issued to the companies on March 9, 2009.
[759] U.S. Commission on Civil Rights, 2016 Environmental Justice: Examining the Environmental Protection Agency's Compliance and Enforcement of Title VI and Executive Order 12,898 at pdf p. 14 (Sept. 2016). (finding that "EPA's Final Coal Ash Rule negatively impacts low-income and communities of color disproportionately."); See also Title VI Civil Rights Complaint and Petition for Relief or Sanction – Alabama Department of Environmental Management Permitting of Arrowhead Landfill in Perry County, Alabama (EPA OCR File No. 01R-12-R4).
[760] U.S. Census Bureau, Census 2000 Summary File 3 (SF 3) - Sample Data, All Census Tracts, "Individual Poverty in 1999," received via email from Professor Paul Mohai, University of Michigan, on Jun. 4, 2010.
[761] See, e.g., Comments of Earthjustice, et. al., on Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Amendments to the National Minimum Criteria (Phase One); Proposed Rule, (Apr. 30, 2018) at 95-110.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 197

Comment Excerpt:

B. EPA Failed To Adequately Identify The Disproportionate And Adverse Impacts Of Coal Ash Wastewater On Communities Of Color And Low-Income Communities Because The Agency Focused On Only Two Adverse Impacts Of Coal Ash Wastewater Discharges.

EPA's E.O. 12898 review ignored numerous environmental and health impacts of coal ash wastewater that could disproportionately impact communities of color and low-income communities. The Agency only focused on the health impacts from the consumption of fish contaminated with lead and mercury and from drinking water contaminated by bromide discharges.[762] The pollutants in coal ash wastewater have far-reaching environmental, health, and financial implications, many which disproportionately impact environmental justice communities.[763] At a bare minimum, EPA should expand its E.O. 12898 review for the proposed rule to encompass the environmental and health impacts of pollutants expected to be released in higher quantities as a result of this rule, including arsenic, selenium, and nitrate/nitrite as nitrogen.

[762] Proposed BCA at 14-1.
[763] See, e.g., Closing the Floodgates: How the Coal Industry is Poisoning Our Water and How We Can Stop It – DCN SE04073, at 2-7, Docket ID No. EPA-HQ-OW-2009-0819-5643 (2013).

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 198

Comment Excerpt:

C. EPA Failed To Take All Lawful And Practicable Steps To Address The Disproportionate Impacts Of The Proposed Rulemaking.

EPA took no meaningful steps to address any anticipated disproportionate impacts on low-income communities and communities of color. The Agency's E.O. 12898 review includes no attempt to fulfill the entire mandate of E.O. 12898 – that agencies not just identify, but also ***address*** disproportionately high and adverse human health or environmental effects of the proposed rule on minority populations and low-income populations.

As elaborated above in this section, there is extensive evidence that this proposed rule will have a disproportionate impact on low-income communities and communities of color. Additionally, EPA identified potential environmental justice impacts from lead and mercury exposure from fish consumption.[764] However, the Agency simply noted these possible impacts, and made no attempt to elaborate on the findings or provide explanations on why any potential negative impacts may be warranted. To fulfill its duties under E.O. 12898, EPA must concretely identify the potential environmental justice impacts of the proposed rule, and then address these impacts, or explain why they cannot be addressed.

[764] Proposed BCA at 14-10.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 199

Comment Excerpt:

XVI. THE PROPOSED RULE VIOLATES EXECUTIVE ORDER 13045 ON PROTECTING CHILDREN FROM ENVIRONMENTAL HEALTH ANDSAFETY RISKS.

Executive Order 13045 provides that:

to the extent permitted by law and appropriate, and consistent with the agency's mission, each Federal agency . . . (a) shall make it a high priority to identify and assess environmental health risks and safety risks that may disproportionately affect children; and (b) shall ensure that its policies, programs, activities, and standards address disproportionate risks to children that result from environmental health risks or safety risks.[765]

The 2019 Proposal does not address the disproportionate risks to children that will result from increased levels of highly toxic substances like mercury and lead that have no safe exposure level. To the contrary, as described in these comments, the 2019 Proposal would exacerbate environmental health risks to children by weakening many of the elements of the 2015 ELG Rule.

EPA harshly concludes that this proposal to roll back the protections in the 2015 ELG Rule and increase the amounts of lead, mercury, selenium and cancer-causing trihalomethanes discharged into U.S. waterways is not subject to Executive Order 13045 because the options presented in the proposed rule "would have a small, and not disproportionate, impact on children."[766] EPA's conclusion disregards the devastating health impacts that very trace amounts of these toxic pollutants have on children.

EPA did not "identify and address" all health and safety risks and did not ensure that the rule addresses the disproportionate impacts to children. Both lead and mercury have life-altering and disproportionate impacts on children that are well-known, but EPA failed to assess all the risks of these pollutants and underestimated the costs associated with impacts that it did address. EPA also did not address the cumulative impacts of multiple toxic pollutants on children.

...

EPA's current proposal does nothing to address these risks to children's health. To the contrary, as described in these comments, the proposed rule would exacerbate the environmental health risks to children by weakening many of the elements of the 2015 ELG Rule.

[765] E.O. 13045, § 1-101, 62 Fed. Reg. 19,885 (Apr. 21, 1997).
[766] 84 Fed. Reg. at 64,670.

Commenter Name: Thomas Cmar
Commenter Affiliation: Earthjustice et al.
Document Control Number: EPA-HQ-OW-2009-0819-8473-A1
Comment Excerpt Number: 204

Comment Excerpt:

XVII. BY FAILING TO CONSULT WITH TRIBAL GOVERNMENTS, EPA HAS VIOLATED EXECUTIVE ORDER 13175 AND ITS POLICY IMPLEMENTING THE ORDER.

Pursuant to Executive Order 13175, it is federal policy "to establish regular and meaningful consultation and collaboration with tribal officials in the development of Federal policies that have tribal implications."[783] A 2009 presidential memorandum reaffirmed the principles in Executive Order 13175, namely, that "consultation is a critical ingredient of a sound and productive Federal-tribal relationship."[784] To implement Executive Order 13175, EPA's policy is to "ensure[] the close involvement of tribal governments and gives special consideration to their interests whenever EPA's actions may affect . . . tribal interests."[785] EPA's policy "takes an expansive view of the need for consultation in line with the 1984 Policy's directive to consider tribal interests whenever EPA takes an action that 'may affect' tribal interests."[786]

EPA acknowledges that it failed to consult with tribal governments regarding the 2019 Proposal pursuant to Executive Order 13175 ("Order").[787] This is contrary to both the plain language of the Order and EPA's own policy for implementing the Order. The Order directs federal agencies such as EPA to consult with tribal officials regarding "the development of Federal policies that have tribal implications," and EPA takes an expansive view of the need for consultation. At minimum, EPA should have consulted with tribes and tribal entities that it consulted during the 2015 rulemaking process, or offered a reasoned explanation for why it did not. Power plants on or nearby tribal lands discharging increased pollution under the proposal will affect tribes, and the Order as well as EPA policy require consultation under such circumstances.

During the rulemaking for the 2015 ELG rule, although EPA also found that the Order did not apply, EPA consulted with federally recognized tribal officials early in the process of developing the rule under EPA's Policy on Consultation and Coordination with Indian Tribes to "enable them to have meaningful and timely input into its development."[788] EPA shared information about the proposed rule with the National Tribal Caucus and the National Tribal Water Council and continued "government-to-government" dialogue by mail correspondence and a conference call.[789]

In 2011, EPA identified 15 plants located on or near tribal lands that are implicated by the 2015 ELG rulemaking and initiated consultation with the tribal officials.[790] Many of the plants on the EPA's 2011 list are still operating and would be subject to the changes in the proposed rule. The list of power plants within or nearby tribal lands affected by the rulemaking includes:
- Hugo Plant, Choctaw OTSA
- Flint Creek, Cherokee OTSA
- Mayo Electric Generating Station, Sappony SDTSA
- George Neal North, Winnebago Reservation
- Lansing Generating Station, Ho-Chunk Nation Off-Reservation Trust Land
- Brame Energy Center, Clifton Choctaw SDTSA
- Roxboro Steam Plant, Sappony SDTSA
- San Juan Generation Plant Station, Navajo Nation Off-Reservation Trust Land

EPA's rationale for failing to apply the Order in the 2019 Proposal is flawed because it failed to consider whether the action would have "substantial direct effects on one or more Indian tribes."[791] EPA considered only the 2019 Proposal's potential effect on tribal government and did not consider that the Order applies because the rule could have a direct effect on the tribe and tribal members.[792] EPA ignored its Policy and did not reference it or its actions in the previous rulemaking in the proposal.

[783] E.O. 13,175, Consultation and Coordination With Indian Tribal Governments, 65 Fed. Reg. 67,249, 67,249 (Nov. 6, 2000).
[784] Presidential Memorandum on Tribal Consultation, 74 Fed. Reg. 57,881 (Nov. 5, 2009).
[785] EPA, EPA Policy on Consultation and Cooperation with Indian Tribes, at 4, https://www.epa.gov/sites/production/files/2013-08/documents/cons-and-coord-with-indian-tribes-policy.pdf (May 4, 2011).

[786] Id. at 2.
[787] 84 Fed. Reg. at 64,669-70.
[788] 80 Fed. Reg. at 67,890.
[789] Id.
[790] See Letter from Robert Wood, EPA, Re: Notification of Consultation and Coordination on Steam Electric Power Generating Effluent Limitations Guidelines and Standards Proposed Rulemaking – DCN SE03816, Docket ID No. EPA-HQ-OW-2009-0819-1768 (Mar. 6, 2012).
[791] 65 Fed. Reg. at 67,249 ("Policies that have tribal implications" refers to regulations, legislative comments or proposed legislation, and other policy statements or actions that have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.)
[792] Cf. id. at 67,248. EPA states that the action does not have tribal implications for three reasons: "It will not have substantial direct effects on tribal governments, on the relationship between the federal government and the Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in E.O. 13175." Id.

43 Statistics

No comment excerpts were received on this topic.

44 Numeric Limits

Commenter Name: Caitlin McHale
Commenter Affiliation: National Mining Association (NMA)
Document Control Number: EPA-HQ-OW-2009-0819-8327-A1
Comment Excerpt Number: 3

Comment Excerpt:

While NMA generally supports the proposed rule's FGD wastewater provisions, we believe additional flexibility is needed related to the proposed numeric limits. Specifically, NMA has concerns about EPA's proposed mercury limits, which are significantly lower than those in the 2015 Rule. NMA agrees that the reductions in mercury that can be achieved with the proposed treatment technologies should be incorporated into the final effluent limits, but some of our members believe that EPA's proposed effluent limits may not be achievable at this time. The effluent limits that are proposed were based on pilot-scale systems and not on an evaluation of long-term commercial-scale systems. As such, there is still uncertainty with the treatment efficiency and long-term performance of these technologies. EPA's proposed effluent limits for mercury should recognize this uncertainty and the limits should be raised accordingly.

Furthermore, these pilot projects also may not fully have considered a wide variety of weather, operational characteristics, and other variables, especially when a unit is operating at full-scale. EPA should consider these variable operating conditions when finalizing the numeric limits and allow facilities flexibility when accommodating these changes. Additionally, several of our members' customers also have flow variations from their FGD absorbers as a result of fuel blending with different coal types. These flow variations can impact the effectiveness of wastewater treatment technologies, such as biological reduction systems, and therefore impact compliance with FGD wastewater limits. Weather and temperature changes can also impact these flow variations and the ability of treatment technologies to reduce pollutants in the wastewater. EPA should consider these challenges in finalizing the rule and make any changes needed to reflect this variability.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 3

Comment Excerpt:

Key Comments on the Proposed Numeric BAT Limits for FGD Wastewater

The proposed limits on FGD wastewater may not be achievable for all power plants employing the proposed BAT for the following reasons:

- A number of the selenium and mercury measurements in the EPA datasets used for determining BAT are above both the daily and monthly proposed numeric discharge limits.
- One dataset referenced Analytical Method 200.8, which is not an EPA approved analytical method found in 40 CFR 136 for quantifying low levels of mercury. Method 200.8 would result in low-biased data for mercury due to volatilization. EPA should follow up to confirm that the appropriate method is used.
- Two of the five pilot datasets had unusually low mercury and selenium in untreated FGD water, relative to the broader industry.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 21

Comment Excerpt:

3.1 **A number of the selenium and mercury measurements in the EPA datasets used for determining ELG limits are above both the daily and monthly average numeric discharge limits.**

EPA established ELG limits based on five pilot tests using LRTR tested downstream of chemical precipitation. Some of the results obtained were not included in setting ELG limits. The reasons for EPA's data exclusion included conditions referred to as "Prior to Steady-State Operation" and "Treatment System Upset or Abnormal Operation" [EPA, 2019a; EPA, 2019b]. However, the reality of treating FGD wastewater is that the complex water chemistry and fluctuating flows make successful treatment challenging. Excluding samples from a pilot (run under more controlled conditions than a real full-scale system) causes the calculation of the ELG limits to be biased low.

Among the values that EPA included in its dataset were some that were not in compliance with the proposed monthly average limit. Others were even above the proposed daily maximum limits. Figures 3-1 and 3-2 show how final effluent data from the pilots (for mercury and selenium, respectively) compared to the proposed ELG limits.

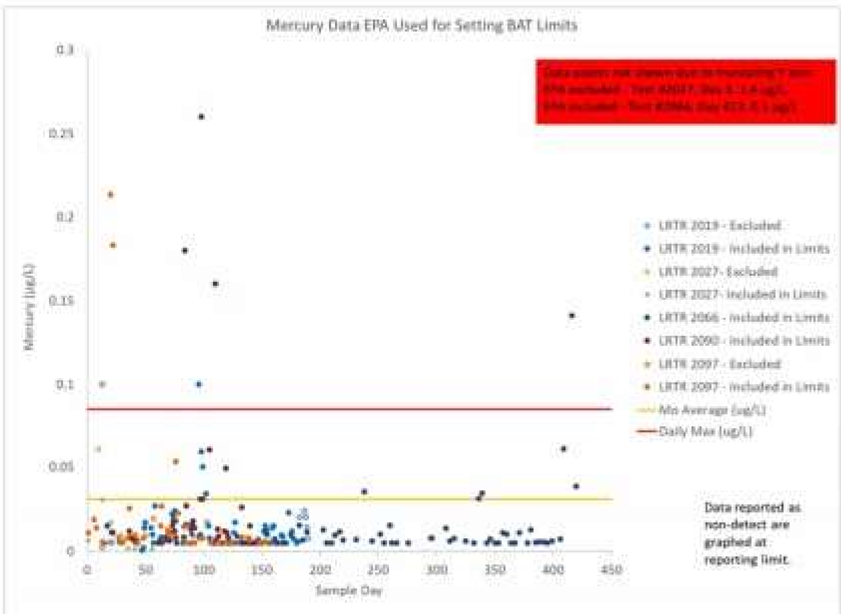

Figure 3-1
EPA five LRTR pilots—Effluent results compared to proposed ELG limits for mercury

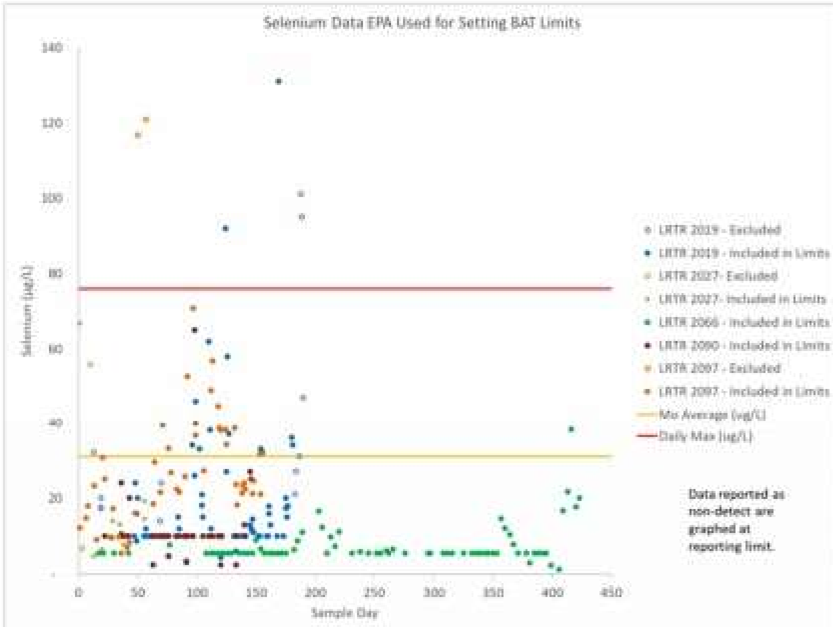

Figure 3-2
EPA five LRTR pilots—Effluent results compared to proposed ELG limits for selenium

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 22

Comment Excerpt:

3.2 **Use of Method 200.8 would bias ELG limit low for mercury due to analytical procedures used.**

In one of the five LRTR pilots that EPA used to set limits (LRTR 2027), the final effluent samples were reported as having been analyzed using EPA Method 200.8 [EPA, 2019a]. Final effluent concentration results for this site reported mercury detections ranging from 0.4 to 4 nanograms per liter (ng/L), with reporting limits ranging from 1.1 to 1.6 ng/L. However, EPRI is not aware of any modification to EPA Method 200.8 that can accurately quantify mercury at this low a concentration; the published method detection limit is 200 ng/L for 200.8. In addition, EPA Method 200.8 is not an approved method under 40 CFR Part 136 for mercury analysis. EPRI suggests that EPA confirm the analytical methods and data quality. If EPA Method 200.8 was actually used, the results would have the potential for low biases due to mercury volatilization in the sample digestion step, and thus this dataset would not be appropriate for inclusion in setting the ELG mercury limits. EPRI suggests that EPA verify these results and determine if inclusion is warranted.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 23

Comment Excerpt:

3.3 **Two of the five pilot tests had unusually low mercury and selenium in untreated FGD influent.**

EPA's LRTR pilot Plants 2027 and 2066 have mercury levels in the influent that are low compared to most other power plant's FGD biological treatment influent, and therefore are not representative of the majority of the industry. This is illustrated in Figure 3-3, which includes sampling effluent from physical/chemical FGD wastewater treatment systems (i.e., biological treatment influent) from a study done by EPRI in 2014 to 2015 of seven FGD power plants [EPRI, 2015]. The plants included in the EPRI study are described in Table 3-1. The plants studied by EPRI had mercury in their untreated FGD wastewater that ranged from 104 µg/L to 1100 µg/L, compared to the 0.3 µg/L median at Plant 2027 and the 3 µg/L median at Plant 2066 for the EPA pilot studies. EPA pilot Plants 2027 and 2066 also had selenium levels in the influent that were low compared to most other power plants: 80 µg/L median and 62 µg/L, respectively. This information is shown in Figure 3-4. Therefore, the two EPA pilot plants do not represent most of the industry, whose plants have mercury and selenium values at least an order of magnitude higher. EPRI suggests that EPA follow up to confirm analytical quality, to understand why the mercury and selenium are so low at these sites, as well as whether the plant operations are representative of the broader industry.

Table 3-1
FGD information from plants used in EPRI study [EPRI, 2015]

Plant Number:	1	2	3	4	5	6	7
Coal Source	Bituminous (~67%)/ sub-bituminous (~33%)	Bituminous (~75%)/ sub-bituminous (~25%)	PRB (100%)	Bituminous (~80%)/ PRB (~20%)	Bituminous	Primarily bituminous	Primarily PRB (~100% for first event; ~75% for second event)
FGD Waste-water Source	Hydroclone overflow, gypsum dewatering	Hydroclone overflow, gypsum dewatering	Hydroclone overflow	Hydroclone overflow	Hydroclone overflow, gypsum dewatering	Hydroclone overflow	Hydroclone overflow
Estimated Scrubber System HRT	6-7 days	5-7 days	18 days	2-3 days	3 days	6 days	10 days

HRT = hydraulic retention time
PRB = Powder River Basin coal

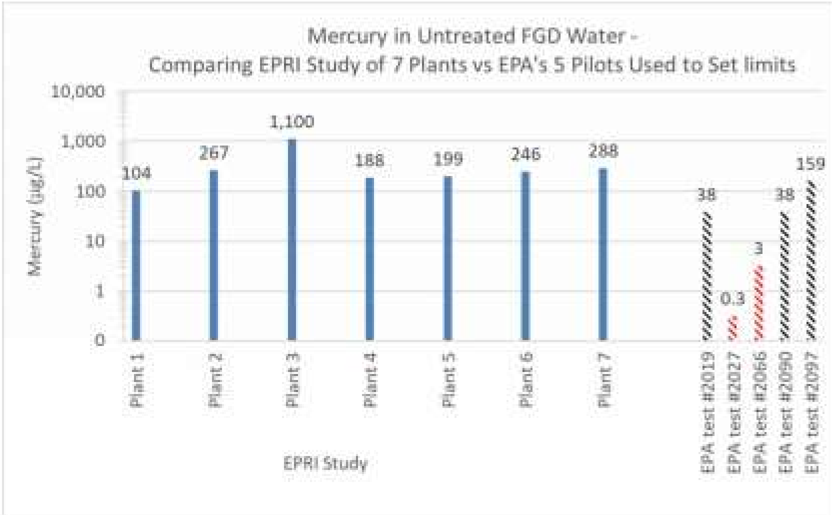

Figure 3-3
Mercury in untreated FGD water from EPRI study of seven plants compared to EPA's five LRTR pilots
(Note that the scale on the graph is logarithmic and that each demarcation is a factor of ten.)

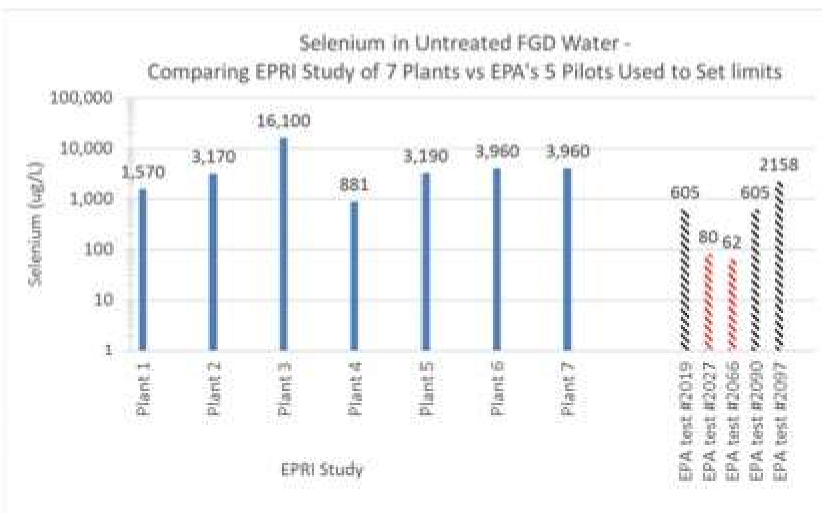

Figure 3-4
Selenium in untreated FGD water from EPRI study of seven plants compared to EPA's five LRTR pilots
(Note that the scale on the graph is logarithmic and that each demarcation is a factor of ten.)

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.

Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 3

Comment Excerpt:

Given the focus of Option 2 in the proposal, Buckeye generally supports the new approach to determining limits on FGD wastewater. The low residence time reactor is more cost-effective than the technology proposed in the prior rule and achieves similar benefits.

Commenter Name: Patrick O'Loughlin
Commenter Affiliation: Buckeye Power, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8309-A1
Comment Excerpt Number: 4

Comment Excerpt:

However, the proposed levels for mercury and selenium are arbitrarily low with no associated benefit. Since the 2015 proposal, EPA gathered information from facilities with treatment technologies in use. Even these facilities EPA used to determine BAT had effluent mercury values above the proposed limits, which demonstrates these values are not actually commercially achievable. Additionally, some of the facilities had pre-treatment mercury and selenium levels significantly lower than those at Cardinal. These lower proposed levels could be nearly impossible for facilities to achieve even with CP+LRTR due to variations in operation. It would be unreasonable for EPA to expect facilities with different operating conditions, including quality of makeup water and background levels, to achieve the same results.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)
Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 18

Comment Excerpt:

The Proposed ELG Rule, however, relies primarily upon pilot LRTR studies that are, by their nature, limited in terms of scope and duration. As a result, the limits do not fully account for the operational variability with both the range of coal types used by units and also the highly variable operating conditions that exist across the generating fleet.

Commenter Name: Alexander Bond
Commenter Affiliation: Edison Electric Institute (EEI)

Document Control Number: EPA-HQ-OW-2009-0819-8314-A1
Comment Excerpt Number: 20

Comment Excerpt:

Pilot projects generally are unable to appropriately account for the deterioration of the ultrafiltration membranes with normal usage, since pilot projects typically use new (or relatively new) equipment and are usually short in duration. As a result, pilot projects are inherently unable to account for basic wear and tear and the impact of widely variable weather, operational characteristics and other circumstances that units might encounter over the longer life span of the installation of control technologies. Specifically, ultrafiltration membranes have a limited shelf life, and how these membranes will perform at removing mercury 12, 24, 36, and 48 months after installation is unknown. EPA, therefore, should take such potential operational variability into account when finalizing the proposed limits, particularly since a degree of flexibility will be needed to accommodate the rapid changes required of the generating fleet during the industry's ongoing transformation.

Additionally, several EEI members have flow variations from their FGD absorbers due to blending different coal types that impacts the ability of wastewater treatment technologies such as biological reduction systems to effectively allow units to maintain compliance with the proposed FGD wastewater limit on a 24/7 basis. Further, these flow variations and the ability of these systems to reduce pollutants in wastewater can be impacted by weather changes, as units dispatch differently based on different weather conditions but also as weather and ambient temperature changes can impact the abilities of LRTR systems to consistently produce numeric outcomes consistent with the limitations in the Proposed ELG Rule. 84 Fed. Reg. at 64,638.

While EPA appropriately proposes that LRTR systems should be the technology basis for establishing BAT limits in a record-supported way, the specific numeric limits in the Proposed ELG Rule necessarily rely on pilot studies that have not 1) been effectuated at full-scale nor 2) performed during the wide variety of operating conditions that units will face daily, which includes facilities operating at variable loads, in load-following circumstances where they are responding to market and system needs, and during the wide variety of weather conditions necessitating different operational requirements. Facilities, however, must meet the applicable numeric limits finalized by EPA once they are incorporated into NPDES permits—regardless of operating circumstances. See 84 Fed. Reg. at 64,662. EPA should therefore take the potential variability of different operational modes across different circumstances into account when finalizing any numeric limits. This is essential since a degree of flexibility is needed to accommodate the rapid changes required of the generating fleet during the industry's ongoing clean energy transition, and the changes in operational mode can be both highly variable and unpredictable in the near- and medium-term.

Commenter Name: American Coal Council (ACC)
Commenter Affiliation: American Coal Council (ACC)

Document Control Number: EPA-HQ-OW-2009-0819-8315-A1
Comment Excerpt Number: 2

Comment Excerpt:

We also believe it is important for EPA to provide flexibility on the numeric limits for FGD wastewater in the proposed rule. Since EPA relied on pilot studies for its proposed numeric limits, full-scale day-to-day operation and a wide variety of operating conditions should be explicitly considered by EPA when finalizing the numeric limits in the rule. Pilot projects are typically shorter in duration and use new or relatively new equipment. Thus, they do not account for longer term wear and tear and the variety of circumstances units may encounter over the life span of the installation of control technologies. One specific area of concern ACC is aware of is the performance of ultrafiltration membranes in removing mercury with longer term use. The wide variety of daily operating conditions encountered includes operating facilities at variable loads, in load-following situations, and in a broad range of weather conditions that necessitate different operational requirements.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 3

Comment Excerpt:

Finally, our comments outline specific technical concerns with proposed FGD effluent discharge limitations for mercury, selenium and nitrate-nitrite contained in the FGD wastewater. The Corporation believes that these proposed limitations are too stringent and must be adjusted to reflect control levels that EPA's selected reference control technology – chemical precipitation combined with low-residence biological treatment and ultrafiltration – can achieve under the full range of operating conditions, including frequent load cycling, burning a variety of coal types, and other operating conditions that may affect the performance and control levels of the reference control technology.

Commenter Name: Toni Presnell
Commenter Affiliation: Oglethorpe Power Corporation
Document Control Number: EPA-HQ-OW-2009-0819-8318-A1
Comment Excerpt Number: 12

Comment Excerpt:

IV. THE PROPOSED EFFLUENT DISCHARGE LIMITATIONS FOR FGDWASTEWATER ARE TOO STRINGENT AND NEED TO BE ADJUSTED.

In the Proposed Rule, EPA selected chemical precipitation followed by a low-residence biological treatment including ultrafiltration as the reference control technology for setting the effluent discharge limitations for FGD wastewater.[11] The chemical precipitation system is designed to remove suspended and dissolved solids, while the biological treatment system with ultrafiltration is focused on removing heavy metals, such as mercury, selenium and arsenic, as well as nitratenitrite. Although generally supportive of EPA's selection of this reference control technology, Oglethorpe Power has significant concerns regarding the effluent discharge limitations that EPA has set for mercury, selenium, and nitrate-nitrite contained in the FGD wastewater based on the application of the control technology.

In the case of mercury, the Proposed Rule would drastically reduce the current maximum daily limitation from 788 to 85 ng/L based on the unrealistic assumption that biological treatment with ultrafiltration can achieve a 90 percent or more reduction of the mercury in the wastewater. Similarly, the proposed maximum daily selenium discharge limitation of 76 ug/L is still too low and must be further increased to account for the high selenium levels that are likely to result from burning certain coal types, frequent load cycling, and other operational factors that either increase the loadings of selenium in the wastewater or limit the effectiveness of the control technology. Finally, the record demonstrates there is no need for a nitrate-nitrite discharge limitation because the data from the pilot tests were almost entirely measured at non-detect levels.[12]

Many of these technical problems with EPA's methodology in setting the proposed FGD discharge limitations are presented in the EPRI comments on the Proposed Rule, which are incorporated by reference into Oglethorpe Power's comments. One notable major shortcoming is that EPA has relied almost entirely on a limited set of data from pilot studies for setting the discharge limitations. Such an overreliance on pilot study data raises significant questions for the following reasons.

First, pilot studies that test the performance of an emerging new control technology differ significantly from testing that control technology at commercial-scale operation. Pilot studies involve the performance testing of highly controlled, small-scale control systems under which specific plant personnel are assigned to continuously monitor the pilot operation and make quick, real-time adjustments to the control system, often before a potential problem even would be detected in a full-scale wastewater treatment facility.

Second, the pilot studies typically test the performance of the control technologies under defined steady-state operating conditions that may differ significantly from normal plant operations. This is clearly the case with respect to pilot data that EPA gathered for evaluating performance of biological treatment system with ultrafiltration. In particular, EPA only collected pilot data when the EGU facilities operated under steady state conditions,[13] which is no longer typical for coalfired generating units. In particular, a majority of coal-fired EGUs now operate on a cycling basis at low annual capacity factors. The cycling on and off of these coal-fired units interferes with the performance of the biological treatment systems. In particular, the changes in FGD wastewater flows and concentration levels due to unit cycling can adversely affect the effectiveness of the microbes within the biological treatment system – given that these microbes must acclimate to each change in wastewater flow or quality. As a result, the effectiveness of the biological treatment system with ultrafiltration can be significantly reduced due to these fluctuations in FGD wastewater flows and consequently impair the ability of the control system to achieve the proposed effluent limitations under typical operating conditions.

Based on the above considerations, Oglethorpe Power believes that the Agency should reconsider the proposed effluent discharge limitations set for FGD wastewater discharges. In so doing, EPA should use test data generated through full-scale commercial applications of biological treatment systems with ultrafiltration, instead of tightly controlled pilot studies that have only limited value on a full, operational scale.

11 84 Fed. Reg. at 64,631.
12 See EPA, Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards, EPA-HQ-OW-0819-2009-8193, Table 11 at page (September 2019) ("Supplemental SSD").
13 In particular, EPA excluded all pilot data that was classified as "Prior to Steady-State Operation" or "Treatment System Upset or Abnormal Operation." See Supplemental SSD at Appendix 2.

Commenter Name: Dorothy Kellogg
Commenter Affiliation: National Rural Electric Cooperative Association (NRECA)
Document Control Number: EPA-HQ-OW-2009-0819-8319-A1
Comment Excerpt Number: 7

Comment Excerpt:

NRECA appreciates EPA's decision to identify chemical precipitation followed by a low hydraulic residence time biological treatment including ultrafiltration (CP+LRTR) as the model technology for development of BAT FGD limits. We are concerned, however, over the agency's reliance on pilot data for deriving the limits. First, by definition, pilot studies are not the same as fully-deployed commercial applications of a technology, and accommodations in the data need to be made to account for the difference between pilot and commercial application. Second, we are concerned that the pilot data reflects, at best, a best case scenario in which regulated units are running at a steady state. Alas, that is not the case as, with increased reliance on non-coal generation, coal-fired units increasingly cycle. This cycling increases the variability of the FGDW generated, in turn, increasing expected biological treatment upsets. Finally, there still are no online, realtime monitors for selenium and mercury creating the untenable situation in which a plant, with not-to-exceed limits, may not be able to detect a problem or exceedance for days or weeks after the fact.

EPA should broaden the data used to set the FGDW BAT limits. First, the agency should include more pilot data from systems that were not operating in a steady state, but specifically data collected prior to a pilot achieving steady-state operations and data collected during system upset or abnormal operations. Such data will be more reflective of increasingly common cycling units and the time-lag to determine any exceedances. Accommodations are particularly critical for the proposed selenium and mercury limits. Finally, we question the need for nitrate/nitrite limits as the biological treatment system designed to remove selenium preferentially removes nitrate/nitrite. The overwhelming number of non-detects in the dataset support the model technology's capacity to remove nitrate/nitrite. Instead, allow the selenium limit to serve as a proxy for any nitrate/nitrites in the effluent.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 2

Comment Excerpt:

EPA Should Review the Technical Feasibility of the Mercury BAT Limits for FGD Wastewater

Duke Energy supports EPA's conclusion with respect to the proposed FGD BAT limits for selenium, nitrate/nitrite, and arsenic. Our experience with operation of advanced FGD wastewater treatment systems (chemical precipitation + biological treatment) demonstrates the proposed limits for these constituents can be achieved through a properly operated and maintained system. However, we disagree with the proposed mercury limits and the methodologies used to derive those limits. EPA's proposed revision to the mercury limits are based on five pilot studies – identified as 2019, 2027, 2066, 2090, and 2097 –, as there is limited available mercury analytical data based on full-scale system operation of the ultrafiltration system.[1] As a result, the limits may not adequately account for the wide variety of operating conditions units will face daily at full-scale operation. Additionally, the deterioration ("age") of the ultrafiltration membranes with normal usage is not accounted for, as pilot tests typically use new (or relatively new) equipment and are usually short in duration. EPA should, therefore, take such potential variability into account when finalizing the mercury numeric limits, particularly since a degree of flexibility is needed to accommodate the rapid changes required of the generating fleet during the industry's ongoing energy transition.

Additionally, some of the analytical results from the pilot tests were excluded in the calculation of the limits. For example, EPA excluded the mercury result of 1.4 micrograms per liter (ug/L) from Day 3 and 0.06 (ug/L) from Day 10 of Test #2027 due to abnormal operations.[2] These results were the two highest mercury results from Test #2027 and both exceeded the proposed monthly average limit of 31 nanograms per liter (ng/L).[3] The reality of treating FGD wastewater is that the complex water chemistry and fluctuating flows make treatment challenging. Excluding samples from a pilot (run under more controlled conditions than a real full-scale system) causes the calculation of the BAT limit to bias low. Duke Energy recommends the inclusion of the analytical results from Day 3 and Day 10 from Test #2027 in the calculation of the final limits.[4]

1 The BAT limits for selenium, nitrite/nitrate and arsenic were based on similar pilot studies. However, based on performance guarantees from the vendor of LRTR the proposed limits for these constituents are achievable.
2 U.S. Envt'l Prot. Agency, "Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards." DCN SE08055. (September 2019), at ES-IV.

3 U.S. Envt'l Prot. Agency "Sampling Data Used as the Basis for Effluent Limitations Based on CP+LRTR or ZVI Technologies." DCN SE08053. September 2019.
4 The sampling data for Test #2027 identified EPA Method 200.8 as the analytical method for mercury. From our understanding, Method 200.8 cannot detect mercury at these low concentrations. It is recommended that EPA verify the analytical method and if Method 200.8 was used, exclude the entire dataset.

Commenter Name: Martha Thomsen, Baker Botts L.L.P.
Commenter Affiliation: Cross-Cutting Issues Group (CCIG)
Document Control Number: EPA-HQ-OW-2009-0819-8326-A1
Comment Excerpt Number: 3

Comment Excerpt:

However, the proposed mercury limits and the methodologies used to derive those limits may be overly constrained and require clarification and revision. There is limited publicly available mercury analytical data in the administrative record that is based on full-scale system operation rather than pilot studies. Because pilot studies appear to have provided much of the mercury analytical data used as a basis for the Proposed Rule, the Proposed Rule may not adequately account for full-scale operation. CCIG therefore requests that EPA provide further clarity on the data used to derive the mercury limits. Additionally, the Group requests that EPA consider increasing those proposed limits to account for full-scale operation.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 2

Comment Excerpt:

APPA has concerns that EPA has based BAT FGD wastewater limits on pilot studies, not full-scale demonstrations. This sets a dangerous precedent for the steam electric point source category and could impact other categories as well.

Commenter Name: Carolyn Slaughter
Commenter Affiliation: American Public Power Association (APPA)
Document Control Number: EPA-HQ-OW-2009-0819-8328-A1
Comment Excerpt Number: 8

Comment Excerpt:

IV. THE USE OF PILOT DATA IN DETERMINING BAT/PSES FOR FGD WASTEWATER IS PROBLMATIC

EPA has evaluated four regulatory options in the proposed rule and is proposing to establish BAT effluent limitations based on the technologies described in its proposed Option 2. For FGD wastewater, EPA is proposing two sets of BAT/PSES limitations: a numeric effluent limit based on total suspended solids (TSS) in FGD wastewater discharge, and numeric limits on mercury, arsenic, selenium, and nitrate/nitrite as nitrogen. EPA identifies treatment using chemical precipitation followed by a low hydraulic residence time biological treatment including ultrafiltration as the basis for control of pollutants discharged in FGD wastewater.

Section 301(b)(2)(A)[8] of the Clean Water Act requires, based on the information available to EPA, the application of the best available technology economically achievable (BAT) for the control of toxic and nonconventional pollutants from direct dischargers. EPA must consider the technological availability and the economic achievability of the control in determining what level of control represents BAT. [9] BAT represents the second level of stringency for controlling direct discharges of toxic and nonconventional pollutants.

In drafting this Proposed Rule, specifically regarding BAT for FGD wastewater, EPA collected new information on both full-scale and pilot-scale treatment technologies. In addition to revisiting facilities that had implemented new FGD wastewater treatment technologies, EPA visited four facilities that had been visited in support of the 2015 Rule because they had recently conducted, or were currently conducting, pilot studies for FGD wastewater treatment. EPA also reviewed various reports published between 2011 and 2018 regarding FGD wastewater treatment pilot studies.

Since Section 301 of the CWA (33 U.S.C. §1311(b)(2)(A)) requires the Agency to promulgate effluent limitations that are "technologically and economically achievable for a category or class of point sources….", it should be axiomatic that the Agency undertake its best efforts to evaluate what is achievable. In the Proposed Rule, the Agency relies too much on pilot data as opposed to full-scale demonstrations. The Utility Water Act Group's comments from July 2017 regarding the Postponement Rule's delay of certain deadlines identifies a few of the problems in relying too heavily on pilot data: namely, that pilot data does not reliably predict compliance across a category or class of point sources, and utilities would have to "continue to expend resources investigating possible compliance strategies for a technology that has not been tested across a broad range of operational conditions." Pilot studies differ from commercial operations. Pilot studies are highly controlled, small scale systems. Personnel monitoring the pilot system are often available to make real-time adjustments, often before problems arise, unlike in a full-scale wastewater treatment system. Moreover, a commercially operating system has much less ability to adjust its feed rate than a pilot and, therefore, less flexibility overall than a pilot. The pilot data EPA used to set the FGD limits excluded data that the Agency determined was "Prior to Steady-State Operation" or collected during "Treatment System Upset or Abnormal Operation."[10] The majority of coal-fired plants now operate on a cycling basis compared to operations in 2015. Cycling on and off causes difficulties with biological treatment systems. Thus, for peaking plants, they do not operate in steady state conditions. EPA's data on net generation shows that the percent utilization of the generating units expected to produce FGD wastewater is relatively low. These units are likely peaking or cycling units with utilization below 50 percent.[11] Given the low utilization, these plants would likely face long period of shutdown. As a result, their biological treatment systems would need time to acclimate once the FGD wastewater flow returns to normal operating levels. This means that the system may not be able to immediately meet the proposed limits.

The best method for the Agency to meet its statutory obligation is to use full-scale demonstrations and not rely predominantly on pilot data to set effluent limitations, but rather include some apparent data abnormalities that could be interpreted to reflect lack of steady state operations and some possible system upsets, because inclusion of those data will help to amend the problems caused by using data exclusively from tightly controlled pilots. To the extent the Agency needs additional time to conduct and factor into its analysis full-scale demonstrations, it should do so.

8 33 U.S.C. § 1311(b)(2)(A).
9 Id.
10 See EPA, Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards, EPA-HQ-OW-0819-2009-8193 (Sept. 2019) (Supplemental SSD), Appendix 2.
11 EPA-HQ-OW-2009-0819-8220, Analysis based on net generation in Table 2.

Commenter Name: Michelle Bloodworth
Commenter Affiliation: America's Power
Document Control Number: EPA-HQ-OW-2009-0819-8330-A2
Comment Excerpt Number: 4

Comment Excerpt:

Another major concern is EPA's overreliance on pilot studies for setting the proposed FGD discharge limitations. Pilot studies typically test the performance of emerging control technologies under defined steady-state conditions that may differ significantly from normal plant operations. This is clearly the case regarding the pilot studies that evaluate the performance of biological treatment systems used to remove nitrogen compounds, selenium and other metals from the FGD wastewater. In particular, the cycling of coal-fired generating units will interfere with the performance of the biological treatment systems and thereby impair the ability of such units to achieve the proposed effluent limitations.

For these reasons, we urge EPA to reconsider the proposed mercury and selenium limitations in order to account for variable operating conditions and other technical issues that may inhibit the performance of the biological treatment systems.

Commenter Name: Doug Brown
Commenter Affiliation: Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois

Document Control Number: EPA-HQ-OW-2009-0819-8331-A1
Comment Excerpt Number: 29

Comment Excerpt:

Use of Pilot Studies in Setting Numeric Effluent Limitations and Determining Environmental Benefit

CWLP agrees with the argument raised by APPA that the proposed rule may be too heavily reliant on pilot studies in establishing the revised numeric effluent limits. The best method for the Agency to meet its statutory obligation is to use full-scale demonstrations and not rely predominantly on pilot data to set effluent limitations. Over-reliance on pilot studies allows for inclusion of some apparent data abnormalities that could be interpreted to reflect lack of steady state operations and some possible system upsets. Inclusion of those data will help to amend the problems caused by using data exclusively from tightly controlled pilots. To the extent the Agency needs additional time to conduct and factor into its analysis full-scale demonstrations, it should do so.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 7

Comment Excerpt:

Turning to FGD wastewater, the "best available technology" limits EPA derived for FGD wastewater based solely on pilot test data need to be adjusted. One pilot used an invalid analytical method to analyze for mercury, so that data should not be used in the mercury limit calculations. Another pilot had very low median influents for both selenium and mercury relative to a set of industry influents and also should not be used for the derivation of limits. These and other adjustments to the data sets are necessary because the limits as proposed are not feasible for the industry as a whole.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 46

Comment Excerpt:

XII. EPA Should Adjust the Proposed FGD Wastewater Limits to Address the ShortComings of the Pilot Test Data.

EPA selected chemical precipitation followed by a low hydraulic residence time biological treatment including ultrafiltration ("CP+LRTR") as the model technology for development of BAT FGD limits. 84 Fed. Reg. at 64,631. The chemical precipitation portion of the model technology would consist of the following steps: equalization, hydroxide and sulfide (organosulfide) precipitation, iron coprecipitation, and removal of suspended and precipitated solids, which are the same elements included in the chemical precipitation technology for the 2015 rule. Id. The LRTR portion of the technology is an anoxic/anaerobic biological treatment system "designed to remove heavy metals, selenium, and nitrate-nitrite." Id. The LRTR stage is followed "by an ultrafilter to remove suspended solids exiting the bioreactor, including colloidal particles." Id.

UWAG generally supports EPA's choice of the model technology. But the limits EPA has derived based on that technology must be adjusted. EPA has relied entirely on pilot data for the derivation of limits using the CP+LRTR model. UWAG supports the use of pilot data in this limited circumstance because, at the time of development of the proposed rule, no commercial data for the CP+LRTR treatment system were available and the LRTR technology has shown promise and builds upon treatment steps used in high hydraulic residence time biological reactors, which have been put into commercial operation. However, the use of pilot data to derive limits raises unique issues, such as whether EPA's standard data selection criteria are appropriate when all of the data in question is from pilot studies.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 47

Comment Excerpt:

A. Pilot Systems Differ from Commercial-Scale Operations.

Unlike commercially operating systems, pilot studies are tightly controlled, small-scale systems. Often, the vendor has personnel on-site who are charged with monitoring the pilot and are available to make quick adjustments to the system. It is possible for operators to make changes and adjustments to pilots in short time periods, often before a potential problem even would be detected in a full-scale wastewater treatment plant. The pilots in the record, despite close observation by competent engineers, nonetheless experienced upsets. EPA, *Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards*, EPA-HQ-OW-0819-2009-8193 (Sept. 2019) ("Supplemental SSD"), Table A2.1 at A2-7 (pilot 2050 through an unregulated air source, inadvertently blew a portion of the carbon bed out of the reactor; pilot 2097 bypassed the ultrafilter on several days). Similar difficulties likely would be magnified at the commercial scale stage.

Also, due to the smaller flow volumes of pilots, the system usually can respond to operator adjustments far more quickly than commercial-size systems. Additionally, a commercially operating system has much less ability to adjust its feed rate than a pilot and, therefore, less flexibility overall than a pilot.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 49

Comment Excerpt:

C. EPA Should Use a Broader Set of Pilot Data to Derive FGD Limits.

For all of the above reasons, EPA should not use the same rules for excluding data from pilots as it does for commercial systems. Instead, EPA should retain some apparent data abnormalities that could be interpreted to reflect lack of steady state operations and some possible system upsets, because inclusion of those data will help to ameliorate the problems caused by using data exclusively from tightly controlled pilots. Only data confirmed to reflect system bypasses or other documented serious failures of the technology should be excluded. UWAG acknowledges that, for these pilot studies, EPA has included some data that might have previously been excluded if this had been a full-scale wastewater treatment plant. UWAG believes that this action has helped make the pilot studies more realistic, because the adverse conditions described are typical of what can frequently occur in a full-scale treatment system. However, some additional data points should be added to the dataset. Specifically, more data from Pilot 2019 should be included, as follows:

- Pilot 2019 data for dates 13, 20, and 21, which EPA excluded as “prior to steady state operation” should be included. Due to the frequent cycling of coal-fired units within the industry (as demonstrated by our analysis of generating unit utilization above) “steady-state” interruptions are the new normal for most FGD units, rather than an abnormal occurrence. The derivation of limits should reflect these data points and any similar ones.
- Pilot 2019 dates 69 and 70 also should be included. The operator noted that there had been an inadvertent feed cutoff from the day before. However, all of the data for these two days are similar to those produced on other days of the pilot, even for selenium, which likely would have been most affected.
- Pilot 2019 dates 183 through 190 should be included as well. This was the second phase of a feed experiment deliberately conducted by the operators toward the end of the pilot operation period. It appears that this may have had some small impact on the selenium results for days 188 and 189, but it recovered quickly. It also is a situation that would be typical when operating a commercial scale wastewater treatment system.

In short, UWAG urges EPA to reevaluate its data exclusions, and apply its criteria in a more realistic fashion, taking into account the possible risks of using pilot data to derive limits and the cycling of units and other variances from normal operations that are now common for coal-fired units generating FGD wastewater, and which will affect the reliability of treatment.[65]

[65] In the Supplemental SSD, EPA outlines another approach to calculating limits based on the pilot studies. See id., Appendix 4, section 2. However, this approach excludes even more data points from the limited dataset than the approach EPA chose. UWAG agrees with EPA that its alternative method for calculating FGD limits—as outlined in Appendix 4—is inappropriate, particularly in light of the exclusive use of pilot data to derive the FGD limits.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 50

Comment Excerpt:

D. EPA Should Adjust the FGD BAT Limits.

EPA's proposed limits for FGD wastewater are as follows:

Pollutant	Maximum, any 1 day	Monthly Avg
Arsenic, total ug/L	18	9
Mercury, total ng/L	85	31
Selenium, total ug/L	76	31
Nitrate/nitrite mg/L	4.6	3.2

Proposed § 423.13(g)(1)(i). Based on input from UWAG members and a review of the record, there are several adjustments that should be made to these limits. First, the mercury limits are far too low and would present compliance problems for many plants. Second, the selenium limits also are too low. Third, the record demonstrates there is no need for a nitrate/nitrite limit.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 51

Comment Excerpt:

1. EPA Should Adjust its Proposed Mercury Limits

EPA used data from five pilots to derive the mercury limits. EPA masked the identities of the pilot plants and chose to identify the pilots by the following numbers: 2019, 2027, 2066, and 2090, and 2097.

EPA specified the analytical methods that it would accept for use in the pilot test data. For mercury, EPA listed Methods 1631E, 245.1, and 245.7. Supplemental SSD at 3. However, Pilot 2027 used Method 200.8 for mercury analysis rather than any of the specified methods. EPA, *Sampling Data Used as the Basis for Effluent Limitations Based on CP+LRTR or ZVI Technologies*, EPA-HQ-OW-0819-2009-8173 (2019). Method 200.8 uses a heated acid digestion procedure without adding any oxidizing agent (such as permanganate or mono-chloro bromine). In contrast, Methods 1631E and 245.1 use oxidizing agents in order to oxidize the mercury into cations that are not susceptible to evaporation on application of heat. Because Method 200.8 does not use an oxidizing agent, it is likely that significant mercury was lost during the analyses of Pilot 2027's samples. Therefore, EPA should exclude all mercury data for Pilot 2027 because of the use of Method 200.8.

Each of the other pilots (2019, 2066, 2090, and 2097) used Method 1631E. Therefore, the data from Pilot 2027 is not comparable to those from the other pilots.

In sum, for the reasons listed below, all mercury data from Pilot 2027 should be excluded in its entirety.

- The pilot used a method not included in EPA's list of specified methods.
- Use of Method 200.8 likely resulted in the loss of significant mercury from the samples.
- Pilot 2027 is the only pilot that used Method 200.8; therefore, it is not comparable to the other pilots, all of which used Method 1631E.

Additionally, EPA should exclude all of the mercury data from Pilot 2066. Both Pilot 2027 and 2066 have very low levels of mercury in their influent. Based on an analysis by EPRI, the mercury level in the influent of these pilots is not representative of typical untreated FGD wastewater. EPRI compared the median mercury results for all five pilots to the median influent levels of mercury in untreated FGD wastewater from a 2014/2015 EPRI study. EPRI 2020 Comments at 3-3 – 3-4. All seven plants in the EPRI report had median mercury influent that was "at least an order of magnitude" higher than either Pilot 2027 or 2066. Id. at 3-3. One of the seven EPRI plants had a median mercury influent of more than 1,000 µg/L. Id. at 3-4. None of the pilots used by EPA had a median value in that range. This analysis suggests that the level of mercury within Pilot 2066's untreated FGD wastewater is not representative of industry mercury levels. For this reason, EPA should not use Pilot 2066's mercury data.[66] It is artificially low as compared to typical industry mercury levels, and therefore the derived limits are biased low.

[66] Also, Pilot 2027's low median influent mercury is another reason to exclude all of the pilot's mercury data.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 52

Comment Excerpt:

2. EPA Should Adjust its Proposed Selenium Limits.

Also, EPA should exclude Pilot 2066's selenium data because its influent levels of selenium are not representative of the industry. Based on an analysis by EPRI, the selenium level in the influent of these pilots is not representative of typical untreated FGD wastewater. EPRI compared the median selenium values for all five pilots to the median influent levels of selenium in untreated FGD wastewater from a 2014/2015 EPRI study. EPRI 2020 Comments at 3-3 – 3-5. As shown in the table below, all seven plants in the EPRI report had median selenium influent values that were much higher than that of Pilot 2066, which has a median selenium value of 62 µg/L. Id. At 3-5.

Plant No.	Median Selenium Influent (ug/L)
1	1,570
2	3,170
3	16,100
4	881
5	3,190
6	3,960
7	3,960

The lowest median influent from the EPRI report is about 14 times higher than Pilot 2066's median selenium value. And the highest median influent in the EPRI report is approximately 259 times Pilot 2066's value. Clearly, Pilot 2066's influent is not representative of selenium influent values for the industry when it is far lower than that of many plants. Therefore, EPA should exclude all of Pilot 2066's selenium data from the limits derivation process.

3. EPA Should Not Set a Limit for Nitrate/Nitrite Because Selenium Limits Will Act as a Surrogate.

EPA used data from pilots 2019, 2066, and 2090 to set nitrate/nitrite limits.[67] But the data indicate there is no need to set a limit for nitrate/nitrite because setting selenium limits will ensure adequate treatment of nitrate/nitrite.

The table below demonstrates a high rate of non-detect values for nitrate/nitrite.

Pilot[68]	No. of Effluent Samples	No. of Non-Detects	No. of Detected Values
2019	72	71	1
2066	76	72	4
2090	43	43	0
TOTAL	191	186	5

Considering all the nitrate effluent samples used to generate nitrate/nitrite limits, about 97 percent are non-detects. And EPA is proposing limits based on only 5 detected values, which is a very limited set.[69]

The near absence of detected nitrate/nitrite values in the treatment system effluent is uniform across all four pilots (2019, 2066, 2090, and 2097). This makes sense because, in bioreactors that are designed for selenium removal, nitrate removal is a precursor reaction that occurs prior to selenium removal. That is, the microbes will first remove nitrate/nitrites and then remove selenium. Therefore, any proposed selenium limits will ensure that nitrate/nitrites are removed as well. In this instance, selenium limits act as a surrogate for nitrate/nitrite limits because the biological reactions that reduce nitrate/nitrites in the system have to occur before there is any significant selenium removals.[70]

Use of surrogate limits, or "indicator" pollutants, is very common in developing effluent limits. As EPA explains in its Permit Writers' Manual:

Effluent guidelines are not always established for every pollutant present in a point source discharge. In many instances, EPA promulgates effluent guidelines for an *indicator* pollutant. Industrial facilities that comply with the effluent guidelines for the indicator pollutant will also control other pollutants (e.g., pollutants with a similar chemical structure). For example, EPA may choose to regulate only one of several metals present in the effluent from an industrial category, and compliance with the effluent guidelines will ensure that similar metals present in the discharge are adequately controlled.

Id. at 5-18. EPA used an indicator pollutant approach in the 2015 rule. In the 2015 TDD, EPA stated:

EPA did not set limits for pollutants that are adequately controlled through the regulation of another indicator pollutant because they have similar properties and are treated by similar mechanisms as the regulated pollutant.

2015 TDD at 11-1. Applying this tactic in setting new source performance standards ("NSPSs") for FGD wastewater, EPA used arsenic, mercury, selenium, and TDS "to represent different solubilities and volatilities of pollutants and act as indicator pollutants for other pollutants." *Id.* at 11-3. EPA also used the indicator pollutant concept in setting the gasification wastewater limits. 2015 TDD at 11-11.

Since the data clearly indicate that nitrate/nitrite levels are almost always non-detect using the model technology, there is no need for EPA to set a nitrate/nitrite limit. Simply setting selenium limits will ensure the removal of nitrate/nitrite.[71]

And, in any event, EPA used an inadequate dataset to derive the nitrate/nitrite limits. The Agency used four effluent samples from one plant and a single sample from another plant. These five effluent samples were the only ones—out of 220 total effluent samples—that were above the detection level. The dataset is simply too small to use for setting limits of nationwide applicability.

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[67] Supplemental SSD at 77-78.
[68] Id., Table 11 at 35.
[69] While EPA chose not to use nitrate/nitrite data from pilot 2097 to set limits, this pilot also demonstrated a very high level of nitrate/nitrite non-detects, with 29 effluent samples, of which 28 were non-detects. Supplemental SSD, Table 11 at 35.
[70] Sonstegard, J., T. Pickett, J. Harwood, and D. Johnson. *Full Scale Operation of GE ABMet Biological Technology for the Removal of Selenium from FGD Wastewaters*, at 5 (2008).
[71] In the 2015 Response to Comments, EPA said it would have set nitrate/nitrite limits even if it had concluded that the biological treatment always removed nitrate/nitrite in advance of selenium removals because it was "aware of … non-biological technologies" that would remove arsenic, mercury, and selenium without removing nitrates. Id. at 8-355. If EPA is referencing the zero valent iron ("ZVI") technology, we are not aware of any commercial application of it to treat FGD wastewater. EPA identified seven pilot-scale studies of this technology but apparently did not identify any commercialscale use of the technology for FGD wastewater treatment. Supplemental TDD at 4-4.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 12

Comment Excerpt:

A. EPA Should Revise the Numeric Limits for Selenium, Mercury and Nitrate-Nitrite.

EPA's proposed BAT limits for FGD wastewater are as follows:[4]

Pollutant	Daily Maximum Limit	Monthly Average Limit
Arsenic, total (µg/L)	18	9
Mercury, total (ng/L)	85	31
Selenium, total (µg/L)	76	31
Nitrate-nitrite as N, (mg/L)	4.6	3.2

The limits EPA derived from five pilot studies need to be adjusted. The proposed mercury and selenium limits are so low that consistent compliance will likely be an issue for many facilities. One of the pilot studies selected by EPA to set the limits is not representative of the industry. Another pilot study used an invalid analytical method to measure mercury. Also, it is well-known that nitrate-nitrite removal is a precursor reaction that occurs prior to selenium removal in biological systems.[5] Thus, nitrate-nitrite levels in the effluent will be de minimis, if any remain, as indicated in the effluent of the five pilot studies. Establishing limits for nitrate-nitrite introduces the possibility of compliance complications due solely to sampling and analytical variability, without much gain from the perspective of reduced pollutant loadings.

4 Id. at 64,673 (to be codified at 40 C.F.R. § 423.13(g)(1)(i)).
5 See JILL SONSTEGARD ET AL., FULL SCALE OPERATION OF GE ABMET® BIOLOGICAL TECHNOLOGY FOR THE REMOVAL OF SELENIUM FROM FGD WASTEWATERS IWC-08-31 5 (2008) (presented at the International Water Conference) (Docket ID No. EPA-HQ-OW-2009-0819- 2079)

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 13

Comment Excerpt:

1. EPA should exclude all mercury and selenium data from Plant 2066.

EPA used pilot study data from five plants to develop the proposed mercury and selenium limits based on chemical precipitation plus LRTR biological treatment (“CP+LRTR”) for FGD wastewater.[6] The pilot datasets are identified as Plants 2019, 2027, 2066, 2090, and 2097. The effluent data used to set the mercury and selenium limits were collected at the effluent of the bioreactor-ultrafiltration system.

Plant 2066 has very low concentrations of mercury (3 µg/L median) and selenium (62 µg/L median) in the untreated FGD wastewater (i.e., the influent to the CP+LRTR system). Based on a study conducted by the Electric Power Research Institute (“EPRI”) in 2014-2015, Plant 2066’s mercury and selenium levels are at least an order of magnitude lower than the seven plants studied by EPRI.[7] Based on EPRI’s analysis of FGD wastewater influent, it is apparent that Plant 2066’s mercury and selenium influent levels are not representative of the industry.[8] Therefore, Plant 2066’s mercury and selenium data should not be used to set industry limits for mercury and selenium.

6 See generally EPA, Sampling Data Used as the Basis for Effluent Limitations for CP+LRTR or ZVI Technologies (2019) (Docket ID No. EPA-HQ-OW-2009-0819-8173).
7 See ELEC. POWER RESEARCH INST., FLUE GAS DESULFURIZATION (FGD) WASTEWATER CHEMICAL PRECIPITATION TREATMENT PERFORMANCE CHARACTERIZATION STUDY 3-7 tbl. 3-1 (2015).

8 See Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., at 3-3 to 3-5 (Jan. 20, 2020) (filed in EPA Docket No. EPA-HQ-OW2009-0819).

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 14

Comment Excerpt:

2. EPA should exclude all mercury data from Plant 2027.

EPA specified the analytical methods it would accept for the pilot study data. For mercury, EPA listed Methods 1631E, 245.1, and 245.7.[9] However, Plant 2027 reportedly used Method 200.8 for mercury analysis rather than any of the specified methods.[10] Method 200.8 is not an approved method for use in compliance monitoring for mercury[11] and uses a heated acid digestion procedure without the addition of oxidizing agents to prevent the evaporation of mercury during the digestion.[12] In contrast, Methods 1631E and 245.1, the approved compliance methods for mercury,[13] use oxidizing agents to prevent evaporation of mercury during the sample preparation step.[14] EPA should therefore exclude the Plant 2027 data from the calculation of industry effluent limits for mercury. In addition to the possibility of having used an improper analytical method, the data presented for Plant 2027 are notably lower than other sites (0.3 µg/L median).

As mentioned above, EPRI's comments on the proposed rule provide a comparison of the influent mercury data of EPA's five pilot studies to seven power plants in its study.[15] The influent mercury data for all seven plants are at least an order of magnitude higher than Plant 2027. The inclusion of Plant 2027's mercury data in the calculation of mercury limits would likely result in limits that are biased low and not reflective of the industry as a whole.

For the reasons provided above, EPA should exclude Plant 2027's mercury data from the calculation of mercury limits.

9 See EPA, SUPPLEMENTAL STATISTICAL SUPPORT DOCUMENT: EFFLUENT LIMITATIONS FOR PROPOSED STEAM ELECTRIC POWER GENERATING EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS 3 tbl. 1 (2019) (Docket ID No. EPA-HQ-OW-2009-0819-8193).
10 See EPA, Sampling Data Used as the Basis for Effluent Limitations for CP+LRTR or ZVI Technologies, supra note 6 (sheet "LRTR 2027").
11 See 40 C.F.R. § 136.3 tbl. IB.
12 See EPA, METHOD 200.8: DETERMINATION OF TRACE ELEMENTS IN WATERS AND WASTES BY INDUCTIVELY COUPLED PLASMA-MASS SPECTROMETRY 200.8-3 (1994).
13 See 40 C.F.R. § 136.3 tbl. IB.
14 See EPA, METHOD 1631, REVISION E: MERCURY IN WATER BY OXIDATION, PURGE AND TRAP, AND COLD VAPOR ATOMIC FLUORESCENCE SPECTROMETRY § 8.0 (2002); EPA, METHOD 245.1: DETERMINATION OF MERCURY IN WATER BY COLD VAPOR ATOMIC ABSORPTION SPECTROMETRY § 8.0 (1994).
15 Comment Letter from Robert Chapman, Vice President, Energy & Env't., Elec. Power Research Inst., supra note 8, at 3-3 to 3-5.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 15

Comment Excerpt:

3. EPA should evaluate the impact of including pilot study data with anomalously low influent selenium concentrations.

Figure 1 shows that, for EPA's five pilot datasets, the influent and effluent selenium concentrations vary by an order of magnitude or more across sites. This variability can influence whether a site will be able to comply with EPA's proposed limits. Figure 2 shows the relationship between average selenium *influent* concentrations and average selenium *effluent* concentrations from EPA's five pilot studies used to derive the selenium limits. There is a positive correlation ($R^2 = 0.6813$), suggesting that higher effluent selenium concentrations could be expected at plants with higher influent selenium concentrations.

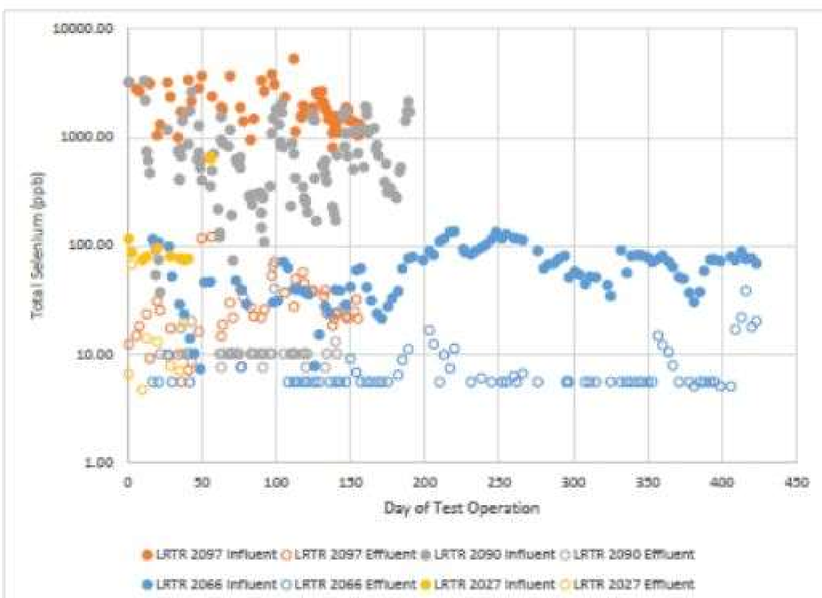

Figure 1. Total influent (closed dots) and effluent (open dots) selenium concentrations from studies used by EPA to derive numeric limits. Note orders-of-magnitude variability in influent selenium concentrations, particularly for Plant 2066.

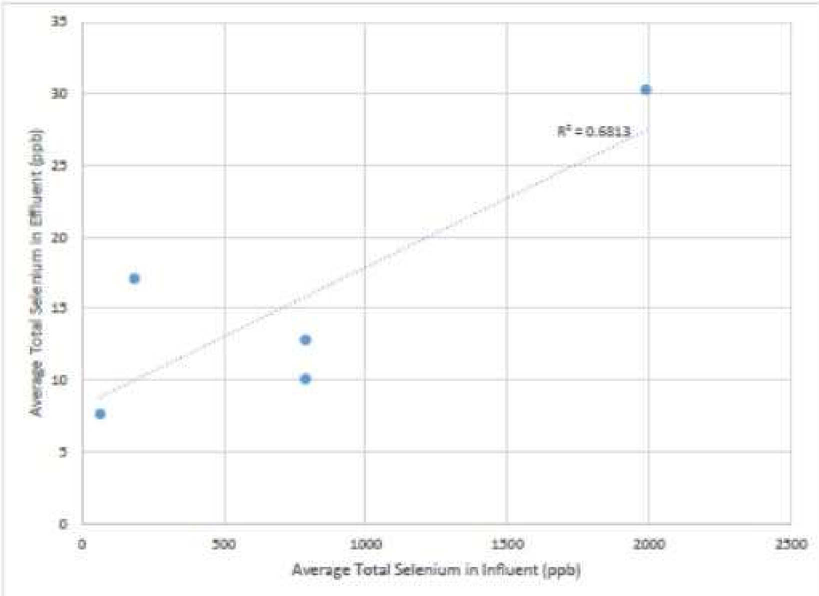

Figure 2. Relationship between average total influent (x-axis) and average total effluent (y-axis) selenium concentrations from five pilot studies used by EPA to derive numeric limits. Note the positive correlation, indicating that higher effluent selenium concentrations are expected at sites with higher influent selenium concentrations.

Because of this relationship, the inclusion of selenium data points from a study or studies with very low influent selenium concentrations that are not representative of the industry (as explained above) could lower the calculated selenium limits to a level that may present compliance risks at plants with relatively higher influent selenium concentrations. As shown in Figure 1, Plant 2066's very low selenium influent concentrations resulted in extremely low selenium levels in the effluent. In fact, 48 of the 75 data points used by EPA to calculate the selenium limits were non-detected values.[16]

The impact of using these data to calculate the limits on site with relatively higher influent selenium concentrations is illustrated in Figure 3, which shows data from Plant 2097 plotted relative to the proposed monthly average and daily maximum compliance limits. It is evident that, during as many as 36 days in the course of this test, selenium concentrations in the effluent are consistently above the proposed monthly (30-day) average limit. While the exact cause of this period of relatively elevated effluent selenium is unknown, [17] it likely reflects the variability that would occur at a plant with such high influent selenium concentrations. The proposed selenium limits will potentially create compliance risks for plants with high selenium influent, such as Plant 2097. Therefore, EPA should exclude all of Plant 2066's selenium data from the selenium limits derivation.

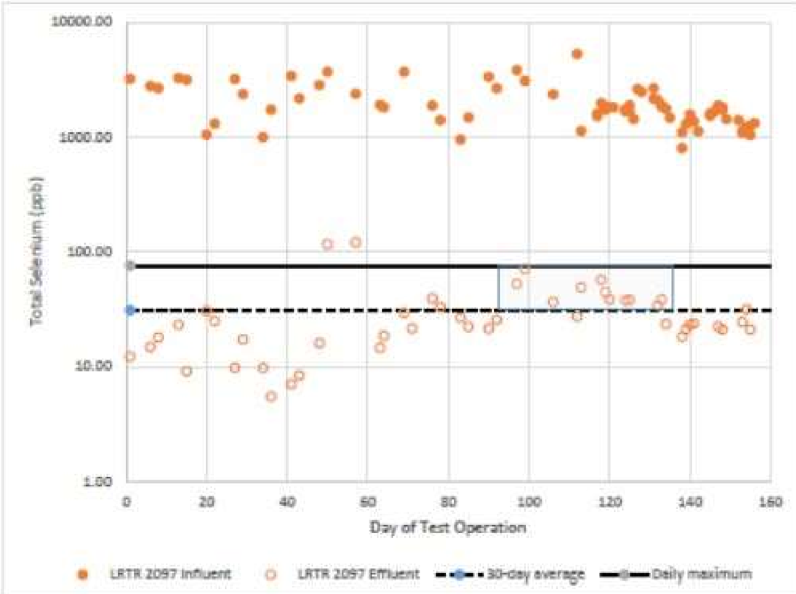

Figure 3. Total influent and effluent selenium data from study at Plant 2097, the site with the highest influent selenium concentrations. Note the extended period of effluent selenium concentrations above the proposed 30-day average limit and instances where the daily maximum limit was also exceeded.

16 See EPA, SUPPLEMENTAL STATISTICAL SUPPORT DOCUMENT, supra note 9, at 39 tbl.
17 Plant 2097 was operating at steady-state conditions during this period. An increase in TDS levels was also observed during this period.

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 16

Comment Excerpt:

4. EPA should reconsider the necessity of nitrate-nitrite limits.

EPA used effluent data from Plants 2019, 2066, and 2090 to set nitrate-nitrite limits. A large majority of the effluent data across all three of these plants are non-detected values, as shown in the table below. EPA used five detected data points out of a total of 191 data points to set the proposed nitrate-nitrite limits:[18]

Plant	No. of Effluent Data Points	No. of Non-Detected Data Points	No. of Detected Data Points
2019	72	71	1
2066	76	72	4
2090	43	43	0
TOTAL	191	186	5

The reason nitrate-nitrite is not detected in a vast majority of the effluent samples is that nitrate and nitrite removal is an integral part of the process of ultimately reducing and removing selenium from solution.[19] In other words, a properly functioning biological treatment system will necessarily remove nitrate and nitrite from solution. It is questionable, then, why EPA must establish a numeric limit for nitrate-nitrate as part of this rulemaking.[20] Deriving compliance limits from less than three percent of the data (five detected values out of 191 data points across three plants) is not appropriate. Establishing limits for nitrate-nitrite introduces the possibility of compliance complications due solely to sampling and analytical variability without much gain from the perspective of reduced pollutant loadings. Southern Company therefore recommends that EPA reconsider the necessity of a nitrate-nitrite limit.

18 See EPA, SUPPLEMENTAL STATISTICAL SUPPORT DOCUMENT, supra note 9, at 35 tbl. 11.

19 See SONSTEGARD ET AL., FULL SCALE OPERATION OF GE ABMET® BIOLOGICAL TECHNOLOGY, supra note 5, at 5.

20 In responding to comments on the 2015 rule, EPA stated it would have set nitrate-nitrite limits even if it had concluded that the biological treatment always removed nitrate-nitrite in advance of selenium removals because it was "aware of . . . non-biological technologies" that would remove arsenic, mercury, and selenium without removing nitrates. EPA, EPA'S RESPONSE TO PUBLIC COMMENTS PART 8 OF 10 8-355 (2015) (Docket ID No. EPA-HQ-OW2009-0819-6469-Att7). If EPA was referencing the Pironox™ zero valent iron ("ZVI") technology, we are not aware of any commercial application of it to treat FGD wastewater. EPA identified seven pilot-scale studies of this technology but apparently did not identify any commercial-scale use of the technology for FGD wastewater treatment. See EPA, SUPPLEMENTAL TECHNICAL DEVELOPMENT DOCUMENT FOR PROPOSED REVISIONS TO THE EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR THE STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY 4-4 (2019) (Docket ID No. EPA-HQ-OW-2009-0819- 8211). Furthermore, the ZVI technology has been shown to reduce nitrates in recent studies. See generally FRANK SASSAMAN ET AL., EVOQUA WATER TECHS. LLC, UNFORESEEN CONSEQUENCES OF CYCLING-UP FLUE GAS DESULFURIZATION (FGD) SCRUBBER WATER IWC 18-12 at 12-13 tbl. 7 (2018) (attached as Attachment 1).

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 4

Comment Excerpt:

TVA also has concerns that the proposed limits may not be acheivable on a consistent basis using only physical/chemical treatment with low residence biological including an ultrafiltration step.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 3

Comment Excerpt:

however, Vistra encourages EPA to revise its proposed effluent limitation for mercury because EPA's proposed limit does not reflect the application of the best available technology economically achievable ("BAT").

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 6

Comment Excerpt:

However, EPA's proposed revisions to the effluent limitation for mercury result in an overly stringent limitation that is not reflective of the application of the BAT identified by EPA, and EPA should revise that limit.

Commenter Name: Cynthia E. Vodopivec
Commenter Affiliation: Vistra Energy Corp. ("Vistra")
Document Control Number: EPA-HQ-OW-2009-0819-8460-A1
Comment Excerpt Number: 13

Comment Excerpt:

EPA proposes to establish BAT limitations for mercury based on chemical precipitation and Low Hydraulic Residence Time Biological Reduction ("LRTR").[27] While Vistra does not take issue with EPA's reliance on chemical precipitation and LRTR biological treatment, Vistra does not believe the proposed limit accurately reflects these technologies. EPA "must set discharge limits that reflect the amount of pollutant that would be discharged by a point source employing the best available technology that the EPA determines to be economically feasible across the category or subcategory as a whole."[28] Here, EPA relied on data from five pilot studies to determine the limitation achievable by chemical precipitation and LRTR biological treatment. As the Utility Water Act Group explains in its comments, one of the pilot studies used an analytical method that EPA had not identified as acceptable and, further, the data from certain other pilot studies is not representative of the industry.[29] Moreover, the pilot studies do not consider operational variability of the generating units and the negative impact that it has on LRTR systems, which require an essential steady-state condition to achieve and maintain optimum effectiveness. In addition, the pilot studies do not represent the variety of wastewater matrices that can occur due to different sources of fuel such as lignite coal. As a result, the mercury limit is overly stringent and is not reflective of the implementation of BAT across the category as a whole, as required by the Clean Water Act. Vistra encourages EPA to revise this limit to accurately reflect application of the BAT at full-scale operations across the full range of facilities within the category.

[27] Id. at 64,631.
[28] Sw. Elec. Power Co. v. EPA, 920 F.3d 999, 1006 (5th Cir. 2019) (citation and quotations omitted).
[29] Comments of the Utility Water Act Group on EPA's Proposed Rule (Jan. 21, 2020) (commenting that EPA should adjust its proposed mercury limits).

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 38

Comment Excerpt:

On this basis, EPRI recognizes two issues in setting the VIP effluent limitations, each of which is discussed in more detail in the subsections below:

- Half of the data points excluded by EPA were justified based on pretreatment upsets or pretreatment abnormal operations.
- EPA's dataset is limited to pilot systems that used chemical precipitation pretreatment upstream of the membrane system. The membrane influent is more closely characteristic of optimized chemical precipitation system effluent than of untreated FGD purge.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 39

Comment Excerpt:

5.2.1 **Half of the data points excluded by EPA were justified based on pretreatment upsets or pretreatment abnormal operations.**

EPRI has developed a summary (Table 5-1) of the final effluent sample datasets used to establish effluent limitations for the VIP membrane filtration technology option. In selecting which data should be included in setting limits, EPA has excluded approximately half of the final effluent data points based on the justification that the pilot system experienced a "Treatment System Upset or Abnormal Operation (Pretreatment Configuration)" [EPA, 2019a]. This is inconsistent with EPA's assertion that advanced membrane systems can be operated without any pretreatment as long as the "existing FGD wastewater treatment in place (is) more advanced than a surface impoundment" [EPA, 2019d]. EPA's handling of the sample dataset suggests that robust chemical precipitation pretreatment and solids settling are required to achieve consistent membrane treatment performance.

Table 5-1
Data EPA excluded based on pretreatment upsets or abnormal operations [1]

Parameter	Final Effluent Data Points	Final Effluent Data Points Excluded for Pretreatment Upsets	Percentage of Final Effluent Data Points Excluded for Pretreatment Upsets
Arsenic	70	32	46%
Mercury	69	32	46%
Selenium	74	35	47%
Nitrate/Nitrite as N	98	58	59%
Bromide	53	25	47%
TDS	63	28	44%

[1] Sampling data used as basis for effluent limits [EPA, 2019a].

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 40

Comment Excerpt:

5.2.2 **EPA's dataset is limited to pilot systems that used chemical precipitation pretreatment upstream of the membrane system. The membrane influent is more closely characteristic of optimized chemical precipitation system effluent than of untreated FGD purge.**

EPA has used a single vendor's pilot data, KLeeNwater, with which to set limits for the VIP option as indicated by the vendor-specific naming convention used for the sampling locations (e.g., "I-Pro Permeate") [EPA, 2019a]. The KLeeNwater pilot data reviewed by EPA [ERG, 2019] included four KLeeNwater pilots conducted on FGD wastewater. Three of these pilot systems reportedly had a physical/chemical pretreatment system operating upstream of the membrane system. The level of chemical pretreatment was not specified for the fourth pilot system, but it was noted that the FGD influent wastewater was low in both chloride (865 ppm) and TDS (4,340 ppm).

Table 5-2 provides a summary of the membrane influent concentrations for the proposed regulated parameters for the KleeNwater pilot systems for plants 4028, 4060, and 4058. The pilot influent data for these plants is compared to EPA's definition of average chemical precipitation system effluent as noted in the 2015 Technical Development Document [EPA, 2015]. As shown in Table 5-2, the membrane influent water is characteristic of optimized chemical precipitation effluent, or in several cases concentrations are uncharacteristically lower than EPA's definition of average FGD chemical precipitation effluent for the industry. Therefore, the performance of the KLeeNwater pilot systems are likely not typical for a membrane system which lacks sufficient pretreatment, such as partial chemical precipitation pretreatment or microfiltration pretreatment.

Table 5-2
Comparison of FGD wastewater feed to membrane pilot systems and FGD wastewater chemical precipitation system effluent

Parameter	Untreated FGD purge [1]	Chemical Precipitation System Effluent [2]	FGD Feed Water (Median value)		
			Plant 4060 Feed Tank Effluent	Plant 4058 FGD Purge	Plant 4028 Pretreatment Influent
Arsenic (µg/L)	507	6	20	10	113.5
Mercury (ng/L)	289,000	139	7.2	1.4	38,800
Selenium (µg/L)	3,130	928	420	574	607
Nitrate/Nitrite as N (mg/L)	91.4	96	250	69	4
TDS (mg/L)	33,300	24,100	13,500	27,050	4,210

Bromide data are not included in comparison table since average bromide concentrations were not provided in the 2015 TDD.
[1] EPA definition of average pollutant concentrations in untreated FGD wastewater per Table 6-3 [EPA, 2015]
[2] EPA definition of average effluent pollutant concentrations for chemical precipitation system per Table 10-4 [EPA, 2015]

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 41

Comment Excerpt:

5.3 **Advanced membrane technologies alone cannot consistently meet the proposed numeric limits.**

In addition to the KLeeNwater datasets with which EPA used to set proposed numerical limits, EPA obtained pilot data for several other vendors since the 2015 ELG rule. This included several sets of pilot data conducted for two other advanced membrane vendor systems, New Logic VSEP and BKT [ERG, 2019]. EPRI has developed a figure showing the average TDS concentration in the membrane permeate as reported by EPA for these pilots [ERG, 2019] in Figure 5-1. Approximately half of the pilot system average values appear to be above the proposed numerical monthly average limit, indicating that the proposed TDS limit may not be achievable for all power plants employing the VIP option. Further, the only vendor data that were able to consistently meet the proposed numerical TDS monthly limit was KLeeNwater, which EPRI noted is likely not representative given that these systems used optimized physical/chemical treatment upstream of the piloted membrane system (Comment 5.2.2). ther vendor technology pilots resulted in higher parameter concentrations in the permeate when physical/chemical pretreatment was not used. For example, VSEP Pilot Study #2 states that “The source of wastewater for the feed tank was the plant’s FGD settling pond” [ERG, 2019].

Further, these data suggest that plants may need to install additional RO systems to polish the permeate in order to meet the proposed numerical limits and/or sacrifice recovery in order to meet the proposed limits. This step could lead to significantly higher costs.

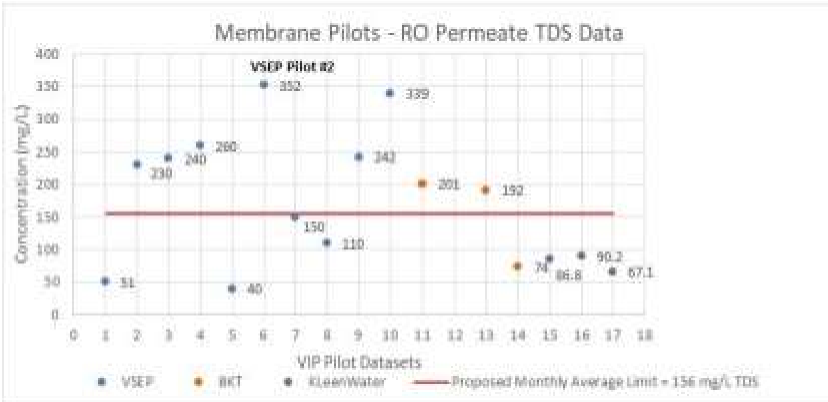

Figure 5-1
Comparison of advanced membrane pilot data, average pilot test TDS concentration in membrane permeate [ERG, 2019]

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 42

Comment Excerpt:

5.4 **The datasets provided to EPA include data above both the daily maximum and monthly average proposed numeric limits; however, the data used for setting VIP limits are based on limited datasets.**

EPRI's evaluation of the individual parameter datasets indicates that data used to set the numerical effluent limits were very limited. The specific issues related to the datasets are demonstrated by discussion of the mercury and TDS datasets in the subsections below.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 43

Comment Excerpt:

5.4.1 **The mercury dataset is very limited.**

The dataset used to set the numeric limits for mercury includes only one detected sample value and five non-detect values. EPA reduced the mercury dataset down to a single detected sample value by excluding several data points that could have been included (Figure 5-2), such as:

- EPA is including only data from the end of the pilot tests with which to set limits. In eliminating data from the earlier days of the pilot tests, EPA is not accounting for the variations that occur in membrane permeate quality for a full-scale system. This ignores data variation due to upsets and variable operating conditions that would be expected to occur at most if not all applications.
- As noted in Comment 5.2.1, EPA has excluded several data points above the proposed monthly average and daily maximum numerical limits on the basis of pretreatment system upsets.
- EPA has appropriately excluded all data using Method 245.1 with higher reporting limits. Method 245.1 is less sensitive compared to Method 1631E.

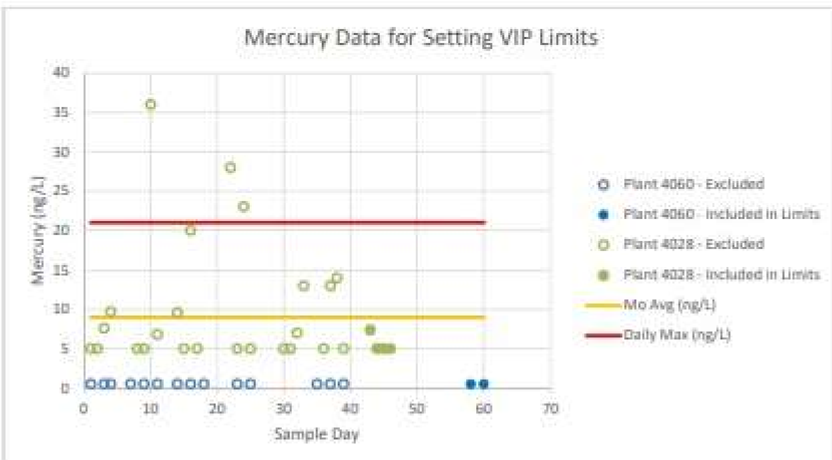

Figure 5-2
Mercury dataset used to set numerical limits [EPA, 2019]

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 44

Comment Excerpt:

5.4.2 **The dataset used to set the TDS numeric limits includes three data points above the proposed monthly average limit and also excludes many data points.**

The dataset used to set the numeric limits for TDS includes 25 data points, three of which were above the proposed monthly average limit (Figure 5-3). Like the mercury dataset, EPA is excluding data from the early days of the pilot testing for two pilot datasets. Also like the mercury dataset, EPA has excluded data based on pretreatment configuration upsets.

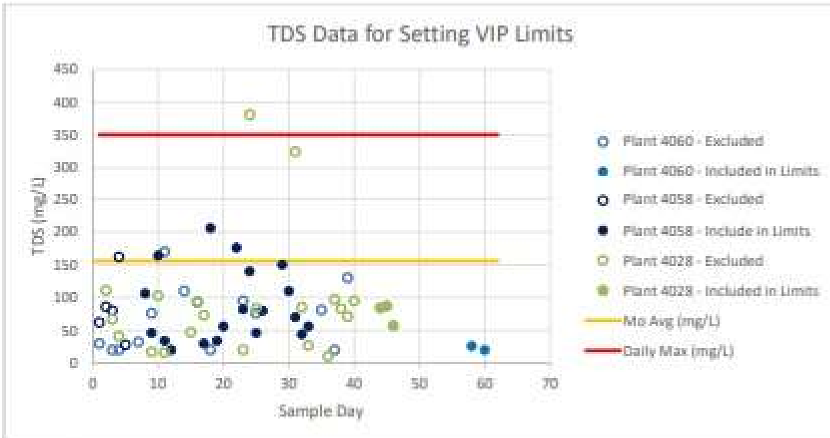

Figure 5-3
TDS Dataset used to set numerical limits [EPA, 2019a]

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 45

Comment Excerpt:

5.5 **EPA's rationale for excluding two datasets should be made clear.**

Although EPA states that they "used data from three power plants (4028, 4058, and 4060) to develop the long-term averages" and numerical effluent limits [EPA, 2019c], the dataset EPA used to set numerical limits for several parameters, including TDS, selenium, nitrate/nitrite, bromide and arsenic, is based primarily on the data from a single pilot system operated at Plant 4058 (Figures 5-3 through Figure 5-7). EPA's methodology for excluding data for the other two datasets is not understood:

- For plant 4028, EPA acknowledged that many data points were excluded for plant 4028 on the basis of chemical precipitation pretreatment, wherein the "period of the pilot (days 1-41), the treatment system configuration was not consistent with the BAT design configuration as the pilot membrane system was used to treat FGD wastewater that had been pretreated by chemical precipitation (i.e., CP effluent)" [EPA, 2019c]. EPA's statistical data summary shows that the only plant 4028 final effluent data that was used to set limits were samples collected on days 43 through 46 [EPA, 2019a].
- For plant 4060, however, EPA stated that they "included analytical results for weeks 4-7 (days 13-40) in the assessment of limits. This data represents a period of the pilot where chemical precipitation was used to pretreat FGD wastewater prior to treatment in the membrane system. Although this configuration does not meet the BAT design, EPA included these data to assess treatment variability." The handling of the dataset for plant 4060 appears to be inconsistent with the handling of dataset for plant 4028. Further, this

> description does not appear to match EPA's statistical data summary [EPA, 2019a] which shows that the only final effluent data used to set limitations for plant 4060 were samples collected on days 58 and 60.

By excluding the data from the other two pilot datasets, EPA may be excluding some representative data with which to set limits. EPA's rationale for excluding these two datasets should be made clear.

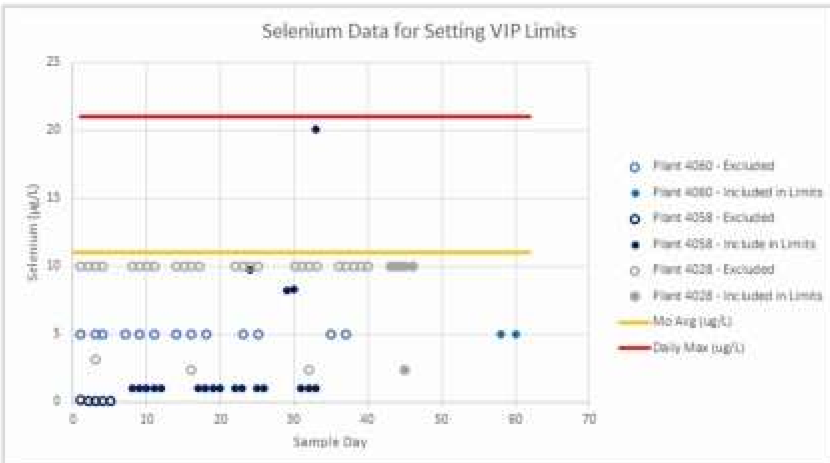

Figure 5-4
Selenium dataset used to set numerical limits [EPA, 2019a]

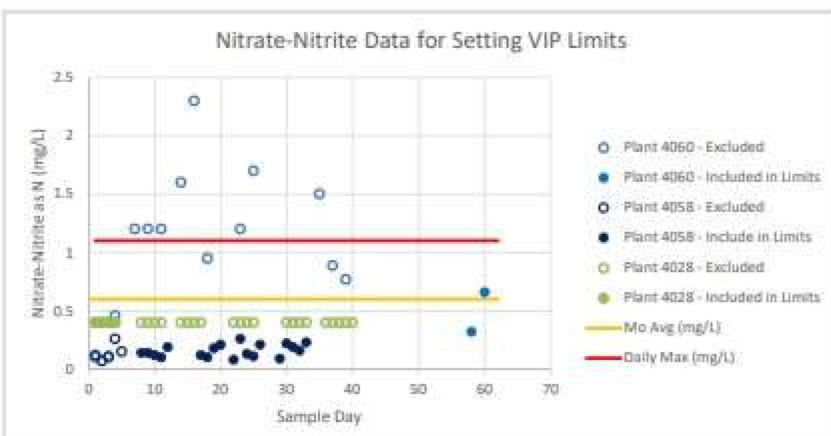

Figure 5-5
Nitrate/nitrite dataset used to set numerical limits [EPA, 2019a]

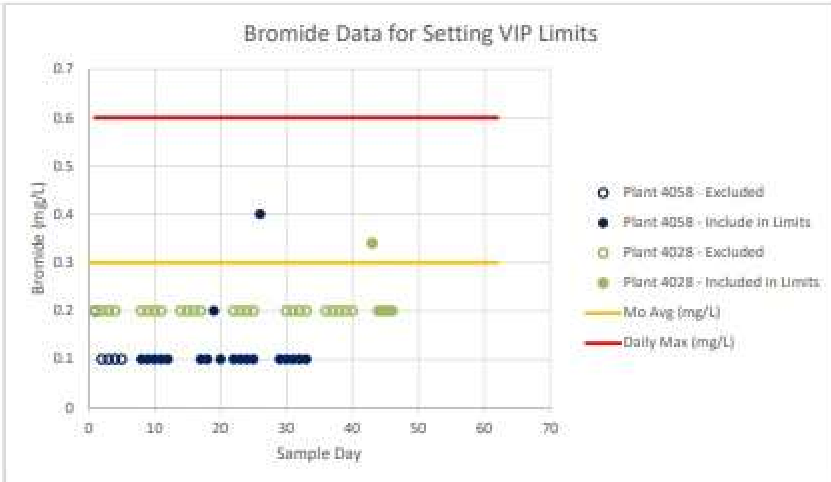

Figure 5-6
Bromide dataset used to set numerical limits [EPA, 2019a]

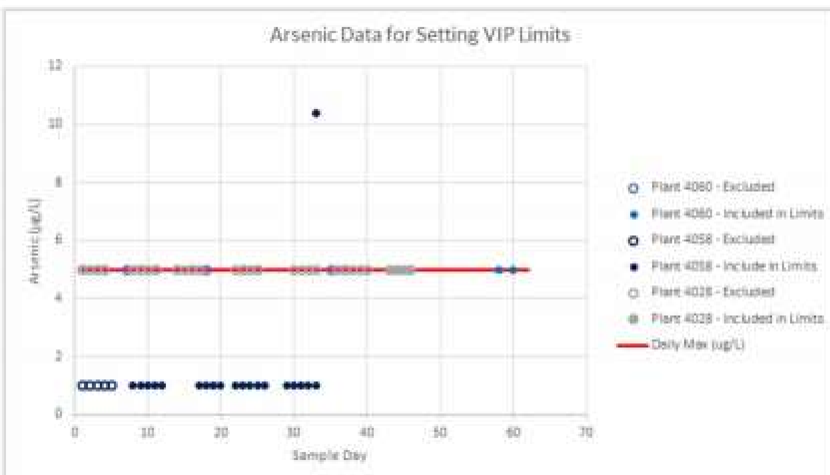

Figure 5-7
Arsenic dataset used to set numerical limits [EPA, 2019a]

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 70

Comment Excerpt:

1. EPA Should Not Set A Monthly Average Limit for Mercury.

EPA proposes the following FGD wastewater limits for dischargers that participate in the VIP program:

Pollutant	Units of Measure	Daily Maximum Limit	Monthly Average Limit
Arsenic	µg/L	5	---
Mercury	ng/L	21	9
Selenium	µg/L	21	11
Nitrate/Nitrite	mg/L	1.1	0.6
Bromide	mg/L	0.6	0.3
TDS	mg/L	351	156

For the VIP technology, EPA evaluated data from three pilots, denoted as pilots 4028, 4058, and 4060. Id. at 78. Since pilot 4058 did not collect any mercury data, only the other two pilots contributed data for that parameter, with 28 values from pilot 4028 and 10 from pilot 4060. Supplemental SSD at 58. As a comparison to the computed monthly average limit, EPA attempted to identify actual monthly average values from the data it had. But EPA determined that pilot 4060 did not collect samples at a sufficient frequency to allow calculation of a monthly average. Id. at 79. For the remaining pilot 4028, EPA had just enough data to calculate a single monthly average value, which it then used to compare to the proposed calculated value of 9 ng/L. It found the one actual value was above the calculated monthly limit. Id.

This is a poor basis for the setting of national limits. First, the mercury dataset comes from only two pilots, with few results over a limited timeframe. Second, the combined dataset contained a high proportion of non-detect values (25 out of a total of 38 datapoints were non-detects). Id. at 58. Third, there was a single monthly average value available to compare to the computed monthly average limit. UWAG urges EPA not to set a monthly average for mercury based on these limited data. The inadequate data for calculating a monthly average and verifying it poses too great a risk that the monthly average limit will not be one that can be consistently met. Without setting a monthly average, EPA nonetheless would regulate mercury through application of the proposed daily maximum limit.

Commenter Name: Ranajit Sahu
Commenter Affiliation: Consultant to EarthJustice, et al.
Document Control Number: EPA-HQ-OW-2009-0819-8474-A2
Comment Excerpt Number: 29

Comment Excerpt:

3.3 History of Selenium ELG Limits for FGD Wastewater

By way of background, it is useful to summarize the progression of EPA's selenium limits as the ELG rule has developed since 2009 through the present proposal. The Table below tracks the respective limits.

Table 3-1– History of ELG Selenium Limits (all values in ug/L) for FGD Wastewater

Regulation (Technology)	LTA	Daily Variability Factor	Monthly Variability Factor	Daily Limit	Monthly Limit	Reference
2013 Proposed Rule BAT (Using CP+HRTR)	7.455	2.145	1.321	16	10	June 7, 2013 Proposed Rule; FR 34490
2015 Final Rule BAT (Using CP+HRTR)	7.5	[Note a]	[Note a]	23	12	November 3, 2015; FR 67870
2015 Final Rule VIP BAT	5 [Note b]			5 [Note b]	-	November 3, 2015; FR 67870
2019 Proposed Rule BAT (Using CP+LRTR)	16.6	[Note c]	[Note c]	76	31	November 22, 2019; FR 64663 (Table XIV-1) and FR 64673 (Table 1 to paragraph (g)(1)(i)
2019 Proposed Rule VIP BAT	5			21	11	November 22, 2019; FR 64663 (Table XIV-1) and FR 64673 (Table 1 to paragraph (g)(1)(i)

Notes

a. As shown in the Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-15-007, September 2015, Table 13-4, the limit was based on CP plus HRTR biological technology at the Allen and Belews Creek plants. The plant-specific LTA, daily variability and monthly variability factors are shown in that table.

b. This limit was based on the Quantitation limit. Thus, there was no monthly limit.

c. Details of the LTA and variability factors are provided in "Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards, September 2019," EPA-HQ-OW-2009-0819-8193, which I discuss below.

Table 13-4. Plant-Specific Results for the Biological Treatment Technology Option for FGD Wastewater

Pollutant	Plant Name	Baseline [a]	Plant-Specific Long-Term Average	Plant-Specific Daily Variability Factor	Plant-Specific Monthly Variability Factor
Arsenic (µg/L) [b]	--	--	--	--	--
Mercury (ng/L) [b]	--	--	--	--	--
Nitrate-nitrite as N (mg/L)	Allen	0	2.549	16.876	3.841
	Belews Creek		0.035	9.360	2.892
	Allen	0.05	2.531	16.779	3.846
	Belews Creek		0.063	2.402	1.454
Selenium (µg/L)	Allen	0	7.134	3.283	1.589
	Belews Creek		7.923	2.779	1.480
	Allen	5	7.391	2.873	1.492
	Belews Creek		8.013	2.618	1.442

a – Where EPA identifies the baseline as zero, this means that the limitations are not based on the baseline substitution approach. Where the resulting value is the same with and without baseline substitution, this means that EPA obtained the same result in both cases.

b – Option long-term average and variability factors were transferred from chemical precipitation technology option for FGD wastewater.

A simple review of Table 3-1 shows how the selenium BAT standard has become progressively less stringent over time and the extent of that weakening.

Considering just the BAT limits, the daily maximum values have increased from 16 ug/L (2013 proposal), to 23 ug/L (2015 Rule), and now to 76 ug/L (2019 proposal). The corresponding monthly limits have increased from 10 ug/L (2013 proposal), to 12 ug/L (2015 Rule), and now to 31 ug/L (2019 proposal). The VIP limits have also become less stringent. In fact, it is worth noting that the 2019 proposed VIP limits are almost similar to the 2015 Rule regular BAT limits (daily maximums 21 ug/L and 23 ug/L; and monthly averages 11 ug/L and 12 ug/L; respectively).

Despite this clear weakening of the selenium BAT limits between the 2015 Final rule and the 2019 proposal—which is over three times less stringent – from 23 ug/L to 76 ug/L – for the daily maximum and a little less than three times less stringent – from 12 ug/L to 31 ug/L – for the monthly—EPA mischaracterizes and glosses over these dramatic reductions in its various statements accompanying the proposed rule.

Commenter Name: Rebecca C. Tolene
Commenter Affiliation: Tennessee Vallley Authority (TVA)
Document Control Number: EPA-HQ-OW-2009-0819-8458-A1
Comment Excerpt Number: 15

Comment Excerpt:

Instead, EPA should establish a "national floor" for the allowable BATW purge discharges in this rulemaking by setting BAT equal to best practicable technology (BPT) limitations.

Commenter Name: Nathan Craig
Commenter Affiliation: Duke Energy
Document Control Number: EPA-HQ-OW-2009-0819-8320-A1
Comment Excerpt Number: 9

Comment Excerpt:

Setting BAT limitations on BA purge water based on total suspended solids (TSS) removal (such as by settling) will provide essentially the same pollutant removal performance as setting BAT limitations based on additional treatment technologies, such as chemical precipitation system with ferric chloride, and organosulfide addition. This is because most of the pollutant load is associated with solids.[14] With the decommissioning of ash basins, Duke Energy constructed concrete lined retention basins to treat and manage miscellaneous waste streams, such as coal-pile runoff, contact stormwater, floor drain wastewater, etc. These systems consist of a primary and a secondary basin with pH adjustment, polymer addition, and retention time to promote solids settling and treatment, which are suitable in managing the discharge from BA transport water systems. Based on analytical data collected within the BA transport water recirculating systems at Duke Energy's Belews Creek and Cayuga Station (Attachment B), the majority of metals detected were in the particulate form demonstrating metals and TSS, are treatable via the low volume waste treatment systems through pH adjustment and solids settling that promote metal precipitation. Placing limitations, therefore, on TSS would effectively control the discharge of any metal constituents present in the BA transport water.

14 Electric Power Research Institute. "Evaluation of Treatment for Closed-Loop Bottom Ash Purges." 300201499. December 2017

Commenter Name: Donna Hill
Commenter Affiliation: Southern Company Services, Inc.
Document Control Number: EPA-HQ-OW-2009-0819-8457-A1
Comment Excerpt Number: 51

Comment Excerpt:

BAT for the BATW purge clearly lends itself to the continuation of the previous Best Practicable Control Technology Currently Available ("BPT") limitations, especially for what amounts to a fraction of the previous BATW discharge. For example, Georgia Power's Plant Wansley has already installed RMDS that result in an approximate 96-98% reduction in BATW discharge when considered on a month-to-month basis. Subjecting the remaining 2-4% purge to BPT limitations is cost-effective, technically defensible and consistent with the Clean Water Act ("CWA") regulatory objective of making meaningful progress towards the elimination of discharges.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 13

Comment Excerpt:

Setting limits on bottom ash loop purge based on solids/total suspended solids (TSS) removal provides pollutant reduction levels comparable to those of chemical precipitation, at significantly lower cost.

Commenter Name: Robert Chapman
Commenter Affiliation: Electric Power Research Institute, Inc. (EPRI)
Document Control Number: EPA-HQ-OW-2009-0819-8293-A1
Comment Excerpt Number: 58

Comment Excerpt:

8.3 **Setting limits on bottom ash loop purge based on solids/total suspended solids removal provides pollutant reduction levels comparable to chemical precipitation at significantly lower costs.**

EPA did not set effluent limitations guidelines on the bottom ash purge, instead proposing that permit writers set ELGs using best professional judgement (BPJ) states “In light of the information discussed above, and the EPA’s authority under section 304(b) to consider both the process employed (for maintenance needs) and process changes (for new treatment systems installed to comply with the CCR rule), the EPA proposes that BAT limitations for any wastewater that is purged from a high recycle rate system and then discharged be established by the permitting authority on a case-by-case basis using BPJ.” Fed. Register, p. 64636.

If, however, EPA were to set BAT ELGs on bottom ash purge water based on TSS removal (such as achieved by settling), it will provide substantively the same pollutant removal performance as setting BAT limitations based on chemical precipitation. This is because most of the pollutant load is associated with solids. Changing from a once-through bottom ash transport (i.e., sluicing to a pond that discharges to a river) to a high-recycle rate system with an allowed purge of up to 10 percent of system volume per day on a 30-day rolling average already reduces pollutants by roughly 94 percent based on EPA’s list of plants, purge estimates, and technology selections, and the single-pass bottom ash flow from Table C-19 of the ELG Information Collection Request.

EPRI’s study of the water quality from the purges of highly recirculated bottom ash systems [EPRI, 2016; EPRI, 2017] indicates the pollutant load in a purge stream will nearly all be associated with solids or low toxicity ions (calcium, magnesium, sulfate). The purge water will have already had most pollutants removed by settling bottom ash out of transport water for reuse.

Such a system could be a remote Mechanical Drag System (rMDS). These rMDS systems typically produce water with several hundred mg/L of TSS (much less than the original sluice water). Some additional particulate removal is possible with additional settling of the purge. Table 8-2 estimates the pollutant removal from the options evaluated. Chemical precipitation would provide very little pollutant reduction beyond that of additional settling but would cost significantly more than additional settling. Chemical precipitation, in addition with settling, results in reductions of less than one percent by mass and four percent based on toxic-weighted pounds-equivalent (TWPE). (TWPEs were used as a metric in establishing prior Effluent Limitation Guidelines and assigns toxicity factors to various constituents.)

The costs of chemical precipitation would be higher as it would require additional chemical feed systems and mix tanks. EPRI has assumed a chemical precipitation system would include ferric chloride, organosulfide, pH adjustment, and polymer addition, whereas a settling system is assumed to only include polymer addition. Chemical precipitation would also have a higher cost for managing the solids removed because the solid slurry from a chemical precipitation system would need to be dewatered separately, requiring sludge holding tank(s) and dewatering equipment such as a filter press. On the other hand, solids from settling systems could be removed in the rMDS.

EPRI estimates that the annualized costs[1] for chemical precipitation for a 100 gpm purge case study would be $2.3 million per year as compared to a tank-based settling system at $0.7 million per year; this cost would be multiplied through the whole industry

Table 8-2
EPRI bottom ash transport water pollutant loading estimate

Description	Pollutant Mass Discharged (lb/yr)	TWPE/yr	Notes
Single-pass bottom ash transport	29,070,000	72,000	Based on EPA's list of plants, single-pass bottom ash flow from Table C-19 of the Information Collection Request, and technology selections. Water quality based on average bottom ash sluice water loadings (i.e., "netting out" source water).
Recycle—with 10% purge	5,580,000	9,300	Based on EPA's list of plants, EPA's purge estimates, and technology selections [EPA, 2019b]. Water quality based on median bottom ash sluice water loadings (i.e., "netting out" source water) from highly recirculated systems.
Recycle—with 10% purge settled to BPT TSS limits	5,370,000	3,500	Based on removal of particulate portion of pollutants based on EPRI sampling data from high-recycle rate bottom ash systems that EPRI sampled from three plants, pro-rating particulate pollutants down to 30 mg/L.
Recycle—with 10% purge treated with CP treatment (no Ca, Mg removal)	5,360,000	3,200	Starts from row above, then assumes 100% removal of divalent ions from settled water, excluding calcium and magnesium which are unlikely to achieve further removal in a chemical precipitation system

BPT = best practicable control technology currently available
lb/yr = pounds per year

[1] Based on 20-year life-cycle and 7 percent interest.

Commenter Name: Jennifer McIvor
Commenter Affiliation: Berkshire Hathaway Energy Company
Document Control Number: EPA-HQ-OW-2009-0819-8297-A1
Comment Excerpt Number: 12

Comment Excerpt:

III. Surface impoundments should be selected as BAT for BA system purge water due to infrequent intervals and large volumes of the discharges.

Under EPA's proposal, discharges of purge water from wet BA handling transport systems would occur on an infrequent basis due to large precipitation events and maintenance, or operational needs.[4] Facilities would seek to limit discharges due to maintenance of the system by taking proactive measures to control the system's water chemistry. Large precipitation and maintenance events are unplanned, sporadic occurrences and, as EPA states in their proposal, could potentially result in large volumes at infrequent intervals. Sizing new treatment technology to treat large volumes of purge water at infrequent intervals and maintaining a treatment system for long standby periods would be problematic and cost prohibitive. It is most likely that some type of impoundment would need to be used to regulate the flow of this water. Facilities have historically used surface impoundments to treat BA transport water, and are experienced at maximizing the effectiveness of this treatment method. Surface impoundments are proven to be cost effective; sites already have existing surface impoundments that could be used to handle BA transport water, shortening the timeframe necessary for facilities to comply with the ELGs. For these reasons, EPA should select surface impoundments, including ash ponds that meet the design and operating criteria of the CCR rule, as BAT.

[4] Id.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 25

Comment Excerpt:

III. BATW Purge: EPA Should set BAT Limits Based on the BMP Plan for Maximizing Recycling.

Again, UWAG strongly supports the BATW 10 percent by volume purge allowance that EPA has proposed, with the adjustments noted above.

A related question is how EPA should regulate the purge discharges. EPA proposes to set new BPT limits for bottom ash purge maintenance water that are equal to those set in the 2015 rule for FGD wastewater, combustion residual leachate ("leachate"), gasification wastewater, and flue gas mercury control wastewater. Those limits are also the same total suspended solid ("TSS") and oil and grease BPT limits as applied to low volume wastes.[24] Proposed § 423.12(b)(11); 40 C.F.R. § 423.12(b)(3).

EPA further proposes that state permit writers should set, using "best professional judgment" ("BPJ"), site-specific "best available technology" ("BAT") discharge limits for bottom ash purge water. 84 Fed. Reg. 64,620, 64,630, n.15. Instead of imposing site-specific BPJ determinations for a small flow such as BATW purge from high recycle rate systems, EPA instead should mandate that operators of high recycle rate BATW systems maximize recycling of BATW, according to the previously described BMP plan.

[24] EPA's separate categorization of bottom ash maintenance purge water is unnecessary. Since EPA excludes the bottom ash maintenance purge water from the definition of "transport water," it classifies as a low volume waste, which is a "catch all" category for miscellaneous discharges. Bottom ash maintenance purge water is appropriately categorized as a low volume waste.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 32

Comment Excerpt:

G. Use of BMPs as BAT is Appropriate for BATW Purge Discharges.

Applying BMPs to industry categories through inclusion in ELG regulations is a well established approach. As the NPDES regulations specify, BMPs may be applied for several reasons, including when "[n]umeric effluent limitations are infeasible." 40 C.F.R. §§ 122.44(k)(1), (3).

In this case, numeric effluent limitations beyond BPT TSS limits are infeasible for BATW purge discharges, including those from high recycle rate BATW systems. The designs of existing BATW treatment systems are quite varied, ranging from RMDS systems to dewatering bin systems to treatment pond systems. Setting a single set of numeric effluent limitations across these existing systems would be extremely difficult and very data-intensive. Even assuming that EPA decided to set a single numeric effluent limitation for each type of system (e.g., one for RMDSs and one for dewatering bin systems), it would be nearly impossible to do so because the systems operate differently according to site-specific conditions. For instance, the amount of recycling within an RMDS system may vary from site to site based on the quality of the intake water. If the RMDS's water source is a brackish body of water, the amount of recycling possible will be less than the amount of recycling possible in an RMDS whose water source is fresh water.

Given variations among the existing systems and those that will be retrofitted with new recycling technologies, a BMP approach is the only feasible solution and ensures a further level of protection above BPT controls.

Commenter Name: Elizabeth E. Aldridge, Hunton Andrews Kurth
Commenter Affiliation: Utility Water Act Group (UWAG)
Document Control Number: EPA-HQ-OW-2009-0819-8456-A1
Comment Excerpt Number: 33

Comment Excerpt:

H. EPA Often Sets BAT Limits Based on BMPs.

EPA has full authority to set BATW BAT limits that are based on use of a high recycle rate system and a BMP plan to maximize recycling based on site-specific factors. EPA has employed BMPs as BAT limits in several prior rulemakings related to concentrated animal feeding operations,[30] construction and development, [31] coal mining, [32] and oil and gas extraction.[33]

In EPA practice, evaluating a candidate BAT technology always means weighing whether the additional pollutant removal is demonstrated and is worth the additional cost of the technology under review. In this case, where the recirculating BATW systems are variable—as are the other treatment systems that the BATW purge may be combined with—it makes sense for EPA to find that BAT is a high recycle rate technology plus BMPs to ensure maximum recycle based on that technology.

The recent decision in *Southwestern Elec. Power Co. v. EPA,* 920 F. 3d 999 (5th Cir. 2019) (*"SWEPCo"*), does not rule out establishing BAT limits on these grounds. In that case, the court weighed EPA's decision in the 2015 rule to establish BAT equal to BPT for two categories of wastewater, legacy wastewater and leachate. The BPT technology at issue for each category was surface impoundments, which act as settling basins to remove pollutants. EPA applied limits consistent with settling in surface impoundments (i.e., limits for TSS and oil and grease) to legacy wastewater and leachate in the 2015 rule.

But in EPA's current proposal, EPA did not deem surface impoundments the model technology for BATW. Instead, after undertaking a thorough review of existing technologies, EPA proposes that dry or high recycle rate BATW treatment systems should be the model technology. 84 Fed. Reg. at 64,630. The fact that high recycle rate treatment systems run most reliably with a small purge stream does not negate EPA's choice of a very advanced technology as the BAT standard for BATW. *SWEPCo* is distinguishable from the case at hand on this ground alone.

The *SWEPCo* court was clear that, if EPA intends to set BAT equivalent to a prior BPT standard, the Agency must explain its rationale in light of the statutory differences between BAT and BPT. 920 F.3d at 1026. As already noted, EPA proposes to apply advanced technologies (dry or high recycle rate treatment systems) as the model BAT technologies for BATW, while the BPT model technology for BATW is surface impoundments. This difference in model technologies reflects the essential statutory difference between selecting the "best available technology economically achievable" and selecting the "best practicable control technology."

In applying the statutory factors applicable to BAT, EPA has "considerable discretion" in weighing those factors. *SWEPCo*, 920 F.3d at 1005-07 (citing *Texas Oil & Gas Ass'n v. EPA,* 161 F.3d 923, 928 (5th Cir. 1998)). In considering the "age of equipment" factor, EPA has the discretion to take account of the industry's short operating history with RMDS high recycle rate systems.

The lack of experience with these systems is evident from EPA's attempt in the 2015 rule to establish RMDSs as the model technology for what was essentially a zero discharge approach to BATW. EPA described the model RMDS technology as consisting of the RMDS trough and chain, a surge tank, a semi-dry silo, and a rental tank to be used for occasional maintenance events, with an enclosed building to protect vulnerable portions of the equipment for sites in locations with a mean daily minimum temperature of less than or equal to 32°F. 80 Fed. Reg. at 67,845 (noting addition of building costs for certain bottom ash systems); EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments* ("2015 Response to Comments"), EPA-HQOW-2009-0819-6469-Att5 (Sept. 2015) at 6-544 – 6-545. But in the Proposed Rule, EPA has acknowledged that what it described as the "model technology" for zero discharge was inadequate. Therefore, in reassessing the RMDS as part of a zero discharge technology, EPA now adds a reverse osmosis system, a surge tank, and associated pumps and piping. Supplemental TDD at 5-45, 5-47.

Allowing a small purge stream for high recycle rate RMDSs and similar technologies is warranted because the industry does not have significant operating experience with these technologies and not all technologies function as well as advertised. EPA has full discretion to consider this issue.

EPA also must consider the statutory factor of process changes. The process of moving from a once-through BATW system, such as a series of surface impoundments, to an RMDS high recycling system will change the characteristics of BATW by increasing the concentration of TSSs. This is a normal result of recycling wastewater. To manage the BATW purge water and its higher TSS levels, in many cases, facilities will need to apply further treatment to the purge water to meet the existing BPT TSS limits. In other words, if EPA establishes BAT limits for purge water that are equivalent to the existing BPT limits, facilities *will nonetheless be applying additional technologies/operational measures to meet the TSS limits*. For instance, the purge water may be sent to the low volume waste treatment system, where it may be adjusted for pH and enhanced settling techniques (such as the addition of polymers) may be used. In short, applying BAT limits consistent with the existing BPT limits does not equate to no further treatment technology in this case.

Finally, under the CWA, EPA has the discretion to consider "other factors deemed appropriate." One major factor EPA has an obligation to consider is the impact of the CCR rule on the industry and on implementation of the ELG rule. The Agency has a duty to avoid creating untenable conflicts that make compliance impossible or near-impossible, from either the CCR or the ELG perspective. If EPA were to mandate BPJ limits for BATW purge water, it would cause significant delays in permitting, as discussed in Section III.B. above. Any delays in issuing NPDES permits reflecting the new applicability dates for BATW retrofits should be avoided because EPA has proposed that all retrofits for BATW be in place by December 31, 2023. Since the rule will not be final until mid-2020, companies cannot finalize designs for their systems and order components until the third quarter of 2020, leaving very little time for issuing requests for proposal ("RFPs"), selecting a vendor, providing the final site-specific engineering specifications, waiting for delivery of the components (which must be fabricated after the order is received), and installing and testing the technology. At the same time, the facilities are under severe time pressure caused by the CCR rule to close or retrofit their surface impoundments and convert their method of handling BATW, as well as deal with non-CCR wastewaters treated within the surface impoundments.

Given these time pressures, requiring a BMP plan to maximize BATW recycle within the system is preferable to engaging in a lengthy BPJ process. Prudence dictates that EPA—having selected advanced technologies as the model BAT technology—not create a BPJ roadblock to major industry transitions. With the rule setting a "not to exceed" 10 percent by volume maximum purge only available under certain limited conditions and site-specific BMP plans to reduce that amount of purge even further, EPA will establish a strict BAT standard that will not adversely impact industry transitions and will ensure significant environmental protections.

[30] *See* 40 C.F.R. §§ 412.4, 412.31, 412.33, 412.43, 412.45 (setting BAT standards equal to BPT standards for Subparts C and D that mandate BMPs such as vegetative buffers, manure and soil sampling, land application inspections, setback requirements, etc.); Final Rule, National Pollutant Discharge Elimination System Permit Regulation and Effluent Limitation Guidelines and Standards for Concentrated Animal Feeding Operations (CAFOs), 68 Fed. Reg. 7176, 7224, 7271-73 (Feb. 12, 2003) (establishing non-numerical BMPs for various subcategories of animal feedlot operations); *see also Waterkeeper Alliance, Inc. v. United States EPA*, 399 F.3d 486, 512-518 (2d Cir. 2005) (upholding BAT standards based on non-numerical BMPs).

[31] *See* 40 C.F.R. § 450.22 (stating BAT limitations must be achieved by erosion and sediment controls, soil stabilization, dewatering, pollution prevention measures, etc.); Effluent Limitations Guidelines and Standards for the Construction and Development Point Source Category, 74 Fed. Reg. 62,995, 63,021 (Dec. 1, 2009) ("EPA is selecting Option 4 as the basis for BAT … [t]he technologies used to meet the limitation in Option 4 are non-numeric effluent limitations or BMPs, the use of polymeraided settling, and site planning techniques such as limiting the amount of land disturbed at any one time or phasing construction activities.").

[32] *See* 40 C.F.R. 434.72, 434.73, 434.82, 434.83 (requiring as BAT/BPT, for Subpart G, implementation of a Pollution Abatement Plan that, among other things, describes "the design specifications, construction specifications, maintenance schedules, criteria for monitoring and inspection, and expected performance of the BMPs" and requiring as BAT/BPT, for Subpart H, submission of a site specific Sediment Control Plan that identifies BMPs); Coal Mining Point Source Category; Amendments to Effluent Limitations Guidelines and New Source Performance Standards, 67 Fed. Reg. 3407, 3379 (Jan. 23, 2002) ("EPA is defining BAT for the Coal Remining Subcategory through a combination of numeric and non-numeric limitations. Specifically, EPA is establishing that the [BAT] for remining operations is implementation of a pollution abatement plan that incorporates BMPs designed to improve pH (as acidity) and reduce pollutant loadings of iron, manganese and sediment, and a requirement that such pollutant levels do not increase over baseline conditions."); *see also id.* at 3384 (establishing "BAT standards … equivalent to BPT" and determining "that BPT for the Western Coal Mining Subcategory consists of designing and implementing BMPs to maintain the average annual sediment yield equal to or below pre-mined, undisturbed conditions"); *see also Citizens Coal Council v. United States EPA*, 447 F.3d 879, 897, 900-901 (6th Cir. 2006) (*en banc*) (concluding "EPA's inclusion of numeric and nonnumeric limitations in the guideline for the coal remining subcategory was a reasonable exercise of its authority under the CWA" and upholding EPA's ELG's for the Western Coal Mining Subcategory).

[33] *See* Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category, 66 Fed. Reg. 6849, 6850, 6876 (Jan. 22, 2001) ("establishing technology-based [ELGs] for the discharge of synthetic-based drilling fluids (SBFs) and other nonaqueous drilling fluids from oil and gas drilling … EPA considered three options for the final rule for the BAT limitation and NSPS controlling SBF retained on

discharged cuttings … EPA selects the second BMP option (i.e., allowing operators to choose either a single numeric discharge limitation with an accompanying compliance test method, or as an alternative, a set of BMPs that employs limited cuttings monitoring) in the final rule.”).

Part 2
COMMENT RESPONSES BY COMMENT CODE

1 Legal Authority

Comments on legacy wastewater and combustion residual leachate

EPA received comments in favor of excluding legacy wastewater and combustion residual leachate from the scope of this rulemaking, as well as comments claiming that EPA is acting arbitrarily by not addressing those wastestreams in this rulemaking. EPA agrees with commenters stating that legacy wastewater and combustion residual leachate should be addressed in a separate rulemaking, and this final rule does not address those wastestreams. EPA announced that it would undertake the current rulemaking to potentially revise the certain 2015 rule effluent limitations and standards applicable to two particular wastestreams, FGD wastewater and BA transport water, in August 2017. EPA received petitions for reconsideration in early 2017 raising serious concerns about the technologies that served as the bases for those limitations and plants' ability to meet them. Following that announcement, EPA began an effort to collect additional data and conduct analyses to support a proposed rule focused on the two aforementioned wastestreams. It was not until April 2019 that the U.S. Court of Appeals for the Fifth Circuit vacated the legacy wastewater and combustion residual leachate limitations in the 2015 rule. Because the current rulemaking was already well underway by that time, EPA determined to continue with the current rulemaking on schedule and to address the Fifth Circuit's vacatur and remand separately.

EPA had at least two reasons for this decision. First, EPA intended to finish the rulemaking related to FGD wastewater and BA transport water before November 2020, which marked the earliest compliance deadlines for the relevant FGD wastewater and BA transport water limitations and standards in the 2015 rule. The timeframe to finalize this rulemaking was estimated assuming only the reconsideration of FGD wastewater and BA transport water limitations. Second, it was not possible to add the combustion residual leachate and legacy wastewater wastestreams to this rulemaking because that would have required the collection of additional information and consideration of different information than the record developed for FGD wastewater and BA transport water. Although EPA received some information on leachate and legacy wastewater, EPA has not sought or specifically requested the data needed to fully analyze the availability and achievability of treatment technologies for those wastestreams.

There are important questions to address and answer on the legacy wastewater, including the cost and performance of various technologies and the potential impacts on the affected plants. Additionally, some commenters raised legal arguments asserting that applying a new BAT requirement to wastewater that is generated prior to the effective date of that new BAT requirement (legacy wastewater) is retroactively overriding the prior legally enforceable BAT requirement. While this legal argument may have merit, it is beyond the scope of this rulemaking. Before EPA can address the leachate and legacy wastestreams, it must consider these and other legal arguments raised by commenters and seek additional information to ensure that its regulatory decisions are based on sound information, legally defensible, and consistent with the CWA. As a result, and as noted in the preamble to the final rule, EPA plans to address the court's vacatur of the legacy and combustion residual leachate wastestreams in a separate rulemaking. This rule is a reasonable step, even if another step will be addressed in the future. The D.C. Circuit has held that "agencies have great discretion to treat a problem partially." *City of Las Vegas v. Lujan*, 891 F.2d 927, 935 (D.C. Cir. 1989) ("Since agencies have great discretion to treat a problem partially, we would not strike down [a regulation] if it were a first step toward a complete solution.").

EPA also notes that some commenters raised issues concerning details about the wastestreams not addressed by this rulemaking, particularly legacy wastewater, the need to account for the potential cumulative economic impacts of any future action to address these wastestreams. These comments are beyond the scope and information collected to support the current rulemaking and are best left to consideration in a future rulemaking concerning those wastestreams.

BAT standard and EPA's consideration of BAT factors

EPA received comments asserting that EPA must consider the statutorily required BAT factors with respect to each, individual BAT technology option, rather than bundling certain technologies together into regulatory options. EPA's analyses for the final rule are consistent with the Clean Water Act's requirements for BAT effluent limitations. *See* 33 U.S.C. §§ 1311(b)(2)(A), 1314(b)(2)(B). EPA considered the technological availability of each candidate technology, along with the estimated costs and associated pollutant removals of each technology, as well other requisite statutory factors like the non-water quality environmental impacts of individual technologies. EPA also estimated and considered the aggregate costs to industry and economic impacts under the entire rule, as the Act makes clear that BAT standards must be economically achievable, and courts have interpreted that requirement to mean that the costs must be reasonably borne by the industry as a whole. *Chemical Mfrs. Ass'n v. EPA*, 870 F.2d 177, 262 (5th Cir. 1989). Because EPA assessed pollutant loadings associated with each of the candidate technologies, EPA disagrees with one commenter who asserted that the Agency did not have information to assess whether the individual technologies could make reasonable further progress toward the Act's goal of eliminating discharges.

This commenter also asserted that "EPA must examine how each BAT affects the statutorily mandated factors relative to the 2015 regulation." The Agency did include the 2015 rule in the baseline for purposes of assessing the impacts of this final rule. As described throughout the final rule preamble and the supporting documents, and EPA explained in each case where it is selecting a technology in this final rule that is different from one selected in the 2015 rule.

The same commenter asserted that EPA must select as BAT the technology that is "best" at making reasonable further progress toward eliminating the discharge of all pollutants. The term "best" is not limited to one meaning, and in fact is defined by the statute as what is technologically available and economically achievable in light of the statutory factors specified in Clean Water Act section 304(b). *See BP Exploration, et al v. EPA*, 66 F.3d 784, 796, 800 (6th Cir. 1995) (In upholding EPA's rejection of reinjection based on total industry cost, the court said, "[t]he CWA's requirement that EPA choose the 'best' technology does not mean that the chosen technology must be the absolute best. Obviously, BAT and NSPS must be acceptable on the basis of numerous factors, only one of which is pollution control.”). *See also Entergy Corp. v. Riverkeeper, Inc*., 556 U.S. 208, 218 (2009) (stating that the term “best” in section 316(b) does not necessarily refer to the one that produces the most of some good (e.g., reduction in adverse environmental impact)).

The same commenter also stated that EPA was obligated to consider the “health and environmental protections” of each candidate technology. These types of impacts and benefits are not required statutory factors for BAT. EPA’s decisions on the final rule are based on the factors specified by Sections 301 and 304 of the Clean Water Act – most importantly, the technologies selected in the final rule are “available” and the final rule is “economically achievable” for the industry as a whole. EPA did evaluate these potential impacts and benefits for the final rule and other main regulatory options as reflected in the Benefit Cost Analysis, but the Agency’s BAT decisions reflected in the final rule are not based on a benefits analysis, which EPA conducts pursuant to Executive Order. The Clean Water Act contains two principle means of water pollution control: technology-based and water quality based. Unlike the water quality-based provisions, in the technology-based provisions of the Act, such as in issuing effluent limitations guidelines, EPA determines what technology is available to control effluent discharges. *See, e.g., Weyerhaeuser Co. v. Costle*, 599 F.2d 1011, 1042 (D.C. Cir. 1978) (impact on receiving water quality not a factor); *Ass’n of Pacific Fisheries v. EPA*, 615 F.2d 794, 805 (9th Cir. 1980) (EPA is not supposed to demonstrate the incremental effect on receiving water quality); *Am. Frozen Food Inst. v. Train*, 539 F.2d 107, 121 (D.C. Cir. 1976) (determination of Best Practicable Control Technology Currently Available (BPT) is not to be based upon the quality of the receiving waters).[1]

Another commenter asserted that the “Best Available Technology is the most stringent pollution control that is available and economically achievable.” EPA disagrees with this statement because, as explained above, “best” is not limited to the technology that achieves the most reduction of discharges of pollutants. BAT is defined by the statute as what is technologically available and economically achievable after consideration of specified factors – including but not limited to cost, non-water quality environmental impacts, and such other factors as the Administrator deems appropriate.[2]

This same commenter also stated that the test for economically achievability is whether the “costs can be reasonably borne by the industry,” and that EPA “is precluded from basing its determination of BAT on a cost-benefit analysis.” EPA agrees that the test for economic

[1] EPA also received comments stating that interstate pollution causes harm to downstream waterbodies in other states. However, as supported by these cases, in setting technology-based effluent limitations, EPA does not consider water quality impacts including downstream impacts in other states (see also the discussion responding to comments on compliance with the Endangered Species Act, below).

[2] This commenter also misquoted the CWA, suggesting that BAT shall require ‘“the elimination of discharges of all pollutants” if “such elimination is technologically and economically achievable.”’ The commenter failed to qualify this language as the statute does with the additional language stating “as determined in accordance with” section 304(b)(2) of the CWA, which requires consideration of the enumerated statutory factors.

achievability is whether the costs can be reasonably borne by the industry, and EPA did not base its decisions in this rule on a weighing of costs against benefits.[3] EPA's decisions on the final rule are based on the factors specified by Sections 301 and 304 of the Clean Water Act. After consideration of age, process employed, engineering aspects, process changes, costs, non-water quality environmental impacts (including energy requirements), and other factors the Administrator deems appropriate, the technologies selected in the final rule are "available" and the final rule is "economically achievable" for the industry as a whole. EPA notes that courts have held that EPA has considerable discretion in evaluating the statutory factors and the weight accorded each factor.[4] EPA's decisions on the final rule are not based on a cost-benefits analysis, which EPA conducts pursuant to Executive Order. The CWA treats the weighing of costs differently under BPT and BAT, and EPA's interpretation of the statute is reasonable in light of the multiple judicial decisions that have noted that BAT, unlike BPT, is to be established without reference to cost-benefit analysis. *See EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 70-71 (1980) ("[I]n assessing BAT[,] total cost is no longer to be considered in comparison to effluent reduction benefits."); *Ass'n of Pac. Fisheries v. EPA*, 615 F.2d 794, 818 (9th Cir. 1980) ("The conspicuous absence of the comparative language contained in section 304(b)(1)(B) leads us to the conclusion that Congress did not intend the Agency or this court to engage in marginal cost-benefit comparison."); *Am. Iron & Steel v. EPA*, 526 F.2d 1027, 1051-52, 1053 n.54 (3d Cir. 1975) ("there should be no cost-benefit analysis" for BAT); *Nat'l Ass'n of Metal Finishers v. EPA*, 719 F.2d 624, 659 (3d Cir. 1983) ("BPT is designed to eliminate inefficient discharges, *i.e.*, where the benefits of pollutant reduction exceed the costs. . . . BAT assumes that inefficient discharges have been eliminated . . . [and] require[es] the remaining dischargers to eliminate 'efficient' discharges, [including] where the costs outweigh the benefits of pollutant reduction.").

The same commenter also asserted that, with respect to the term "available" in BAT: "A technology need not even be in commercial use to be available, so long as the technology has been studied and demonstrated, such as through the use of pilot studies. EPA may also conclude that a technology is available if it is in use in another industry, so long as it shows that that technology is transferable to the industry class for which it is establishing BAT." The statute gives EPA considerable discretion in evaluating available information and data and weighing the statutory factors. Where EPA is concerned that a pilot study or the use of a technology in another

[3] The commenter also stated that the Supreme Court has held that BAT limits "represent[] a commitment of the maximum resources economically possible to the ultimate goal of eliminating all polluting discharges." EPA does not dispute this statement, but rather views it as only a piece of the relevant inquiry for BAT, since BAT must be shown to be technologically available and economically achievable after consideration of the Clean Water Act section 304(b) factors. 33 U.S.C. §§ 1311(b)(2)(A), 1314(b)(2)(B).

[4] *See, e.g., Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) ("The EPA nonetheless has considerable discretion in evaluating the relevant factors and determining the weight to be accorded to each in reaching its ultimate BAT determination. *See Natural Resources Defense Council v. EPA*, 863 F.2d 1420, 1426 (9th Cir. 1988). Thus, the EPA has significant leeway in determining how the BAT standard will be incorporated into final ELGs."); *Weyerhaeuser Co. v. Costle*, 599 F.2d 1011, 1028, 1042 (D.C. Cir. 1978) ("[T]he listing of factors seems aimed at noting all of the matters that Congress considered worthy of study before making limitation decisions, without preventing EPA from identifying other factors that it considers worthy of study. So long as EPA pays some attention to the congressionally specified factors, the section on its face lets EPA relate the various factors as it deems necessary.").

industry is not applicable to all the conditions faced by the industry, it is more legally defensible for EPA to decline to base BAT on those technologies. Indeed, EPA has received court remands in these types of rules where it did not adequately consider all the factors applicable to the industry. *See, e.g., Ass'n of Pacific Fisheries v. EPA*, 615 F.2d 794, 820 (9th Cir. 1980) (remand for failure to consider land acquisition costs); *Hooker Chemicals & Plastics Corp. v Train*, 537 F.2d 620, 632 (2d Cir. 1976) (remand for failure to consider whether recycle technology could be feasibly applied to plants in cold climates); *FMC Corp v. Train*, 539 F.2d 973, 985 (4th Cir. 1976) (remand where EPA based limitations for the plastics and synthetics industry on what could be achieved by a technology used by municipal treatment systems and waste facilities in the petroleum industry, but the record was "devoid of any consideration by EPA of transferability" of the technology). EPA may also choose not to base BAT on pilot plant performance or use in other industries where statutory factors (*e.g*., non-water quality environmental impacts) weigh against the particular technology. *See, e.g., BP Exploration & Oil, Inc. v. EPA,* 66 F.3d 784, 800-802 (6th Cir. 1995) (upholding EPA's rejection of a zero discharge technology option that was otherwise found to be technologically available and economically achievable based on the Agency's findings that the option would result in unacceptably high non-water quality environmental impacts).

One commenter stated that EPA's citation of *American Petroleum Institute v. EPA*, 787 F.2d 965 (5th Cir. 1986), in the preamble discussion of FGD wastewater, was misplaced because the pollutant loadings reductions estimated for the 2015 rule are not "*de minimis*." EPA disagrees and clarifies that the Agency did not establish BAT controls in this rule on the basis that additional reductions from another technology would be *de minimis*. Rather, in selecting LRTR biological treatment over HRTR biological treatment as part of the BAT technology basis for control of pollutants discharged in FGD wastewater, EPA noted that both technologies achieve very similar levels of pollutant loadings reductions (some pollutant loadings are expected to increase while others will decrease), while the LRTR technology is less costly, involves fewer process changes and has a smaller footprint at a plant. In citing *American Petroleum Institute*, 787 F.2d 965, EPA simply pointed out that courts have recognized discretion in the statute for the Agency to determine that the technology-based approach has its limits. *See also Ass'n of Pacific Fisheries v. EPA*, 615 F.2d 794, 818 (9th Cir. 1980) ("So long as the required technology reduces the discharge of pollutants, our inquiry will be limited to whether the Agency considered the cost of technology, along with the other statutory factors, and whether its conclusion is reasonable. Of course, at some point extremely costly more refined treatment will have a *de minimis* effect on the receiving waters.").

Comments on "weakening" effluent guidelines

One commenter stated that, under the Act, EPA may revise technology-based limitations "to become only more stringent." EPA disagrees that it cannot finalize a rule that is less stringent than the 2015 rule. This rulemaking represents a reconsideration of the 2015 rule based on additional information and data that was not available to the Agency when the 2015 rule was promulgated. At the time EPA initiated reconsideration, many plants had not yet implemented the requirements of the 2015 rule. As of the date this rule is being finalized, many plants still have not implemented the requirements of the 2015 rule. The reconsideration was undertaken because certain parties raised serious questions about the availability and affordability of the technology basis for the FGD wastewater and BA transport water requirements in the 2015 rule. The Administrative Procedure Act contemplates that agencies can revise their rules, *see* 5 U.S.C. § 511(5), definition of rulemaking, which includes revision of a rule, and section 553(e), which affords people the ability to petition the agency for the issuance, amendment or repeal of a rule. And it is indisputable that EPA has considerable discretion under the CWA in deciding how to account for the consideration factors and the weight to be accorded to each factor. *See* W*eyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1045 (D.C. Cir. 1978); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 214; *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998). Furthermore, it is well established law that Agencies can change their policy decisions, including how the Agency weighs various statutory factors, and the Supreme Court has held that changes to Agency rules are not subject to more searching review than first instance policy decision. *FCC v. Fox Television Stations*, 556 U.S. 502, 515 (2009). That means that the standard for reviewing the decision here is governed by the traditional test articulated in *Motor Vehicles Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29 (1983), which looks at whether the rule is rational, based on consideration of the relevant factors, and within the scope of the authority granted by the statute.

Thus, while some commenters argue that making the rule less stringent is prohibited, they have not offered – and EPA is not aware of any – statutory basis for that claim. If EPA weighs the relevant factors consistent with and within the permissible bounds of the Act, then the resulting decision comports with the Act. EPA's decisions are upheld in such instances, *see, e.g., BP Exploration & Oil Inc. v. EPA*, 784, 797 (6th Cir. 1995) (In rejecting petitioners' argument that EPA was compelled to establish BAT limitations as zero discharge, the court said, "We think that EPA acted within its statutory authority in rejecting zero discharge based on reinjection. As EPA correctly points out, NRDC's contention that economic, energy, and non-water quality environmental impacts are less important than achieving zero discharge merely reflects NRDC's disagreement on a policy level. This Court may not substitute NRDC's judgment, any more than our own, for that of the EPA.").[5]

With respect to some commenter's view that the final rule is inconsistent with the Clean Water Act because the statute requires BAT to make "reasonable further progress," EPA notes that the statute specifies that reasonable further progress must be measured in light of the statutory factors, as EPA has done here. 33 U.S.C. §1311(b)(2)(A) (BAT effluent limitations "will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants, *as determined in accordance with regulations issued by the Administrator pursuant to section 304(b)(2) of this Act* . . . .") (emphasis added). The final rule goes beyond the previously established BPT requirements and establishes limitations based on chemical precipitation plus low residence time biological treatment for control of pollutants in FGD wastewater and based on high recycle rate systems for control of pollutants in bottom ash transport water. EPA has

[5] In addition, EPA notes that the Agency's antibacksliding regulations expressly allow for modification of technology-based permit limits based on promulgation of revisions to an ELG. 40 C.F.R. 122.62(a)(3)(i).

determined that these limitations make reasonable further progress toward the national goal of eliminating the discharge of pollutants, based on the information and data in the rulemaking record that informed EPA's consideration of the statutory factors. In any case, for FGD wastewater, some of the limitations in this rule are more stringent than those in the 2015 rule (e.g., mercury limitations are more stringent by an order of magnitude), and EPA projects additional reductions of FGD wastewater pollutant loadings under this rule as compared to the 2015 rule as a result of projected participation in the VIP. For BA transport water, the permitting authority is authorized to determine based on best professional judgment the volume of BA purge wastewater that may be purged from a plant's high recycle rate system (not to exceed ten percent), and may, in some circumstances, determine that this amount should be zero. In such cases, the limitations under this rule would be equal to those established under the 2015 rule.

Consistency with Southwestern Electric Power Co. v. EPA

After careful consideration of the record, along with applicable judicial precedent, EPA has identified surface impoundments as the BAT technology basis for the control of pollutant discharges in BA transport water from electric generating units in the low-utilization subcategory, and surface impoundments as the BAT technology basis for the control of pollutant discharges in bottom ash transport water and FGD wastewater from electric generating units in the subcategory for units permanently ceasing combustion of coal by 2028. For the low-utilization subcategory, the BAT technology basis is, more specifically, composite lined surface impoundments.

EPA disagrees with commenters who asserted that these aspects of the rule are inconsistent with the Fifth Circuit's decision in *Southwestern Electric Co. v. EPA*, 920 F.3d 999, (5th Cir. 2019). In that case, the Court held that EPA's decisions in the 2015 steam electric rule naming surface impoundments as the BAT technology basis for controlling discharges of pollutants found in legacy wastewater and combustion residual leachate were arbitrary and capricious and inconsistent with the Clean Water Act, respectively. The decisions made in the 2015 rule are distinguishable from the decisions made in this rule. Most importantly, in the 2015 rule, EPA did not base its BAT decisions on legacy wastewater and combustion residual leachate on express statutory factors. Rather, in the 2015 rule, EPA justified its decision on legacy wastewater on the fact that many plants commingle various wastestream into a single legacy wastewater, and EPA lacked data on the variability of this wastewater across the industry; and EPA justified its decision on combustion residual leachate on the reasonable further progress made by other parts of the 2015 rule and the relatively small amount of pollutant loadings represented by the leachate wastestream. For legacy wastewater, the Court found it arbitrary for EPA to determine that surface impoundments were BAT for legacy wastewater (which was defined as one or more of several wastestreams addressed in the 2015 rule generated before the rule's later compliance dates) while at the same time determine more advanced technologies were BAT for the individual wastestreams that compose legacy wastewater when generated after the rule's later compliance dates. *Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999, 1017. Moreover, the Court stated that "the rule merely states— without explanation—that it lacks 'data to characterize the effluent from these systems'" and that "the record fails to explain why impoundments are BAT, if that term is to have any meaning. Furthermore, if chemical precipitation or biological treatment are technically feasible but simply too costly for treating legacy wastewater, the EPA could have said so." *Southwestern Electric Co. v. EPA*, 920 F.3d at 1018 n.20. The Court also suggested that the Agency's lack of data was of its own doing, as the 2015 rule acknowledged that multiple plants were, in fact, using chemical precipitation to treat legacy wastewater, indicating the Court thought EPA could have obtained data from these plants.6 *Id*. at 1020. For combustion residual leachate, the Court stated that "on their face, the justifications for the leachate BAT put forward in the rule fall outside of the factors mandated by the Act for determining BAT." *Id*. at 1026.

For this final rule, EPA's decisions are based firmly on its consideration of the CWA statutory factors and its rationale is thoroughly explained in the preamble and supporting documents. EPA's final decisions do not conflict with the findings of the Fifth Circuit, rather, consistent with the Court's decision the Agency developed BAT in context and with reference to the larger statutory scheme. *Southwestern Electric Co. v. EPA*, 920 F.3d at 1018 n.20. For example, EPA did not select surface impoundments as the BAT technology basis for certain subcategories of units based on lack of data or based on the small amount of pollutant loadings or progress made by the rest of the rule. Rather, EPA has explained why surface impoundments are BAT and has offered an explanation that falls within the express factors mandated by the statute. In particular, EPA has found that, for these wastestreams and subcategories, surface impoundments are technologically available and economically achievable in light of the statutory factors in Section 304(b), including that they impose acceptable costs and non-water quality environmental impacts (including energy requirements). At the same time, EPA rejects other technologies, not because these are relatively small wastestreams or that the rule otherwise makes reasonable further progress, but based on the statutory factors specified in the Clean Water Act, as contemplated by the Court in *Southwestern Electric Power Co. v. EPA.* 920 F.3d. at 1025 ("[I]t is not the case that §1311(b)(2)(A)—standing apart from the factors in §1314(b)(2)—unambiguously required EPA to set a stricter BAT for leachate.").

The statutory factors include non-water quality environmental impacts. In the final rule, EPA concluded, based on this factor, that low utilization electric generating units should continue to be available in times of higher energy demand. Without this subcategorization, EPA determined that these units are more likely to be closed, not making them available during periods of peak demand. EPA has broad discretion to consider energy impacts and the weight to afford such impacts. *See BP Exploration, et al v. EPA*, 66 F.3d 784, 803 (6th Cir. 1995) (In upholding EPA's decision not to require zero discharge of drilling fluids and drill cuttings in certain locations, the Court recognized the discretion afforded the Agency under the statute and stated, "If any entity has the ability to weigh the relative impact of two different environmental harms, it is the

[6] The Agency notes that the plants identified in the 2015 rule using chemical precipitation to treat commingled legacy wastewater were subject to regulation under the Clean Water Act. As such, EPA could have compelled the production of information or data through its authority under CWA section 308. This is in contrast to the foreign facilities EPA understands are operating membranes to treat FGD wastewater, as these facilities are not subject to EPA authority and cannot be compelled to produce information or data about the operation of those membrane systems.

EPA.”). Given the discretion afforded to consider the statutory factors, the question is whether EPA reasonably considered those factors. Importantly, this means that, under this portion of the Clean Water Act, it is possible that more than one policy choice is within the Administrator’s discretion. It is well established that administrative agencies possess the inherent authority to revise previously promulgated rules, so long as they follow the proper administrative requirements and provide a reasoned basis for the agency decision. *See F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).

EPA has also determined that other technologies considered in this rule, including zero discharge technologies, high recycle rate technologies, chemical precipitation, biological treatment, and membrane filtration are not BAT for these subcategories because they would impose unacceptable impacts in the form of disproportionate costs or unacceptable non-water quality environmental impacts (including energy requirements). *See* preamble sections VII.C.2 and 3. Caselaw supports that EPA has significant discretion to consider the relevant factors and the weight to afford each factor. *See, e.g., See BP Exploration, et al v. EPA*, 66 F.3d at 796 (In considering costs, “EPA is governed by a standard of reasonableness in considering the factors to be balanced. As EPA elucidates, *Chevron* requires that agencies are given significant discretion, on a case-by-case basis, in weighing factors, provided the agency’s regulations are not ‘manifestly contrary to the statute.’”) (quoting *Chevron, U.S.A., Inc. v. NRDC, Inc.*, 467 U.S. 837, 844 (1984) and citing *Am. Iron & Steel Inst. v. EPA,* 526 F.2d 1027, 1051 (3d Cir. 1975)). Thus, unlike the 2015 decision to base BAT on impoundments based on lack of data or the relative importance of the wastestream (rather than the CWA statutory factors), EPA’s decisions in this final rule are based on the statutory factors specified in the Act. Despite language in *Southwestern Electric Power Company v. EPA* raising certain concerns with surface impoundments, the Fifth Circuit and other applicable caselaw affords EPA considerable discretion in weighing its BAT decision on the statutory factors specified in section 304(b). Courts should uphold those reasoned decisions as long as the statutory factors were considered and the decision is not manifestly contrary to the statute. EPA has done just that in this rulemaking.

With respect to the commenters’ claims about surface impoundments being “not effective at reducing discharges of pollutants to surface water,” EPA has clarified that surface impoundments are capable of reliably and consistently achieving limitations on Total Suspended Solids (TSS), have been installed to treat most of the different steam electric power plant wastestreams, and have been meeting TSS limits at plants for decades. TSS can include many constituents, including particulate forms of metals such as mercury or selenium. In this final rule, after consideration of the statutory factors, in the limited instances where EPA is identifying surface impoundments as the BAT technology, EPA is establishing limitations on TSS. These limitations are expected to continue to reduce the amount of particulates, including particulate forms of metals and any pollutants adsorbed to particulates, that will be discharged to surface waters. The removal of particulate pollutants is expected even in surface impoundments that may experience conditions (e.g., low pH) that could convert particulate forms of metals to soluble forms, surface impoundments that receive FGD wastewater, or during seasonal turnover. *See also* the response to Code 10 (Surface Impoundments).

Some commenters referenced the Fifth Circuit's language about "reasonable further progress" and statements in the 2015 rule regarding surface impoundments not making reasonable further progress, and asserted that surface impoundments are not BAT. In response, EPA clarifies that the statements in the 2015 rule were made in the context of EPA's finding that technologies other than surface impoundments were technologically available and economically achievable in light of the statutory factors. In this final rule, for discharges from certain subcategories of units, EPA finds that technologies other than surface impoundments are not available and achievable within the meaning of the Act, and surface impoundments are the technology that reflects BAT. *See* 33 U.S.C. § 1311(b)(2)(A). Moreover, the statute specifies that reasonable further progress must be measured in light of the statutory consideration factors, as EPA has done here. *Id*. (BAT effluent limitations "will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants, *as determined in accordance with regulations issued by the Administrator pursuant to section 304(b)(2) of this Act* . . . .") (emphasis added). And, courts have held that EPA has considerable discretion in evaluating the factors and the weight accorded each factor.[7]

Bottom ash transport water

EPA received comments that the Agency cannot rely on "cost" as a factor for selecting high recycle rate systems rather than dry handling or closed loop systems for control of pollutants in BA transport water. EPA disagrees but notes that it has cited cost as an additional, rather than the controlling, factor in its decision to select high recycle rate systems over dry handling or closed loop systems. In other words, EPA would make the same decision regarding its technology selection even without reference to the cost factor. See the preamble Section VII.B.2. As the preamble explains, cost is an express statutory factor under Clean Water Act section 304(b) that EPA must consider in establishing BAT, and EPA recognizes that there is an additional, non-trivial cost to industry in operating closed-loop systems. Industry-wide, EPA conservatively estimates the costs of the additional measures needed to achieve and maintain a fully closed-loop system to be $63 million per year in after-tax costs, beyond the costs of the systems themselves. EPA did not make its decisions in this rule based on a weighing of cost against benefits. See above regarding EPA's choice not to use benefits or a weighing of costs against benefits as a BAT decision factor.

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[7] *See, e.g., Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) ("The EPA nonetheless has considerable discretion in evaluating the relevant factors and determining the weight to be accorded to each in reaching its ultimate BAT determination. Thus, the EPA has significant leeway in determining how the BAT standard will be incorporated into final ELGs.") (citing *Natural Resources Defense Council v. EPA*, 863 F.2d 1420, 1426 (9th Cir. 1988)); *Weyerhaeuser Co. v. Costle*, 599 F.2d 1011, 1028, 1042 (D.C. Cir. 1978) ("[T]he listing of factors seems aimed at noting all of the matters that Congress considered worthy of study before making limitation decisions, without preventing EPA from identifying other factors that it considers worthy of study. So long as EPA pays some attention to the congressionally specified factors, the section on its face lets EPA relate the various factors as it deems necessary.").

EPA also received comments stating that it lacked record support for reliance on the statutory factor of "process changes" in selecting high recycle rate systems for control of pollutants discharged in bottom ash transport water. The commenter states that because Duke Energy in North Carolina installed lined retention basins, other utilities can do the same, thereby avoiding having to send non-BA transport water to their BA transport water treatment system in anticipation of the fast-approaching CCR rule deadlines. EPA disagrees, as explained in the preamble, because Duke Energy designed its high recycle rate BA transport water system to handle additional wastestreams in addition to BA transport water. Thus, it is not true that Duke's experience means that the routing of non-BA transport water through the high recycle rate BA transport water system would not cause operational issues with the system at other plants, as discussed in the preamble. Moreover, where plants do not already have lined retention basins to handle the additional wastewater, the need to segregate wastestreams rather than send non-BA transport water to the BA transport water treatment system could result in plants needing to use their surface impoundments for longer periods while they build alternative capacity. While the CCR rule allows plants to request site-specific alternative closure extensions from the otherwise applicable April 2021 deadline for ceasing receipt of waste in unlined surface impoundments, EPA does not intend to encourage prolonged use of impoundments that can otherwise meet this deadline.

Finally, one commenter claimed that EPA cannot use the above rationale in establishing BAT because it involves what plants are likely to do with other wastestreams. This commenter asserted that, to be consistent with the Fifth Circuit's decision in *Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999 (5th Cir. 2019), "BAT must be set only in reference to the waste stream in question, not others." EPA disagrees that its rationale is inconsistent with *Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999 (5th Cir. 2019). In that case, EPA declined to establish more stringent limits for the combustion residual leachate wastestream, citing the reasonable further progress that the rule made as a whole, but the Fifth Circuit held that EPA must make a BAT decision for each wastestream independently based on the statutory factors. *Southwestern Elec. Power Co*., 920 F.3d at 1027 ("[T]he rule explicitly justifies a less stringent BAT for leachate by touting the benefits of stricter BATs for *other* wastestreams. But the Act does not permit the agency to set a BAT by playing one pollution source off against another."). In this case, EPA is making a BAT decision for BA transport water only with reference to all the express statutory factors in Clean Water Act section 304(b). The only relevance of other wastestreams in EPA's decision here is related to EPA's consideration of the statutory factor of "process changes," and in particular the kinds of process changes that are happening at plants as a result of requirements plants are facing under the CCR rule and how those process changes affect the treatment of bottom ash transport water.

Subcategorization

In the context of the subcategory for high flows, some commenters argued that the Clean Water Act does not allow it to establish a subcategory of one based on cost. EPA does not agree that the subcategory for plants with high flows is inconsistent with the Act. EPA has authority in a national rulemaking to establish different limits for different plants after considering the statutory factors listed in Clean Water Act section 304(b). *See Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 938 (5th Cir. 1998) ("We find nothing in the text of the Clean Water Act indicating that Congress intended to prohibit the promulgation of different effluent limits within a single subcategory of point sources. . . . The fact that the EPA must promulgate rules for classes of polluters rather than individual polluters does not mean that the EPA is required to treat all polluters within each class identically. The phrases 'for categories and classes' and 'within such categories or classes' simply do not, by their terms, exclude a rule allowing less than perfect uniformity within a category or subcategory."). Here, after a careful consideration of all of the requisite statutory factors, EPA has determined that plants that have particularly high FGD flows are different from other plants in the industry with respect to the compliance costs they would incur if they were expected to achieve the otherwise applicable limits based on CP+LRTR. While EPA is currently aware of only one plant that operates with flows at this high level, any plant in the industry that operates with these flow levels would qualify for the different limits established in this subcategory.

Some commenters argue that EPA is prohibited from establishing a subcategory for which only one facility may qualify because there is a separate provision, Clean Water Act section 301(n), 33 U.S.C. § 1311(n), that allows facilities to apply for a Fundamentally Different Factors (FDF) variance if it seeks to have different limitations apply from those established in a nationally applicable ELG rule. EPA does not agree that Clean Water Act section 301(n) restricts EPA's authority to establish subcategories. The factors and EPA's discretion under Section 301(b) and 304(b) are not constrained by the limits on EPA's discretion under Section 301(n). Rather, Section 301(n) provides an "acceptable alternative to subcategorizing an industry to account for plant-specific characteristics." *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 221 (5th Cir. 1989) (citation omitted). While EPA is "not required to establish separate subcategories for single plants," *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 239, it is not prohibited from doing so. Furthermore, FDF variances are different from subcategories in important ways because they typically are based on information that EPA did not have a chance to consider in a national rulemaking. *See* C.F.R 125.31(a)(2) (a request for establishment of effluent limitations based on fundamentally different factors shall be approved only if the factors are "fundamentally different from those considered by EPA in establishing the national limits"). The CWA section 301(n)(1)(A) preclusion of an FDF variance based on cost makes sense in that EPA had already been required to consider costs during the rulemaking, but only to make a general rather than a precise assessment of costs. *BP Exploration & Oil Inc. v. EPA*, 66 F.3d 784, 800 (6th Cir. 1995) ("The CWA does not require a precise calculation of BAT and NSPS costs.") (citation omitted); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 237-38 (5th Cir. 1989) ("The Act requires the EPA to 'take into account' the costs of BAT; it does not require a precise calculation. The EPA 'need make only a reasonable cost estimate in setting BAT'; it is sufficient if the EPA develops 'a rough idea of the costs the industry would incur.'") (citations omitted). Once that is done, because that is all that is required, the choices on that score in a rule are not to be revisited or second-guessed in an FDF variance. *See EPA v. National Crushed Stone Ass'n*, 449 U.S. 64, 85 (1980) (stating that a plant's economic capability is not a factor for an FDF variance). Congress understood that rulemaking for an entire industry is complicated, and it is possible that in some cases information may not have been made available or may not have been considered by the Agency in the development of a rule's standards. As a result, Congress provided EPA, with concurrence of the State, the time-limited ability in CWA section 301(n) to grant case-by-case FDF variances to existing sources where conditions at a site are different than those considered when the standard was originally developed or if the applicant did not have reasonable opportunity to submit information and supporting data during the rulemaking. *See, e.g., Chem. Mfrs. Ass'n v. NRDC*, 470 U.S. 116, 120 (1985) ("EPA has faced substantial burdens in collecting information adequate to create categories and classes suitable for uniform effluent limits, a burden complicated by the time deadlines it has been under to accomplish the task. Some plants may find themselves classified within a category of sources from which they are, or claim to be, fundamentally different in terms of the statutory factors. As a result, EPA has developed its FDF variance as a mechanism for ensuring that its necessarily rough-hewn categories do not unfairly burden atypical plants."). Thus, FDF variances are intended to address conditions that EPA did not consider during the rulemaking, and the limits on such variances do not govern the discretion afforded EPA in Sections 301(b) and 304(b).

Commenters also argue that EPA is not permitted to establish a subcategory based on cost, based on language in the FDF variance provision, Section 301(n). EPA disagrees. Section 301(n) does not constrain the factors to be considered for BAT under Section 304(b). Under the latter section, EPA is required to consider "cost", and that includes consideration of costs for a subcategory. *See Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 239 (5th Cir. 1989). EPA has broad discretion in deciding how to account for the consideration factors and the weight to be accorded to each factor. *See* W*eyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1045 (D.C. Cir. 1978); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 214; *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998). The question for any reviewing court then is not whether the statute categorically or explicitly prohibits a category of one based on costs – it does not – but whether given the broad discretion to consider costs afforded in the statute, the Administrator reasonably exercised that discretion.[8] In establishing the high-flow subcategory, EPA has determined that total capital costs of a CP+LRTR system are a reasonable way to consider cost in this scenario because they demonstrate the significant up-front disparity created just to install the system. EPA acknowledges that the capital cost estimates for the installation of CP+LRTR developed by the Agency at proposal were, and continue to be for the final rule, higher than TVA's estimates, but notes that the O&M costs are nearly identical. EPA's estimated capital costs for Cumberland amount to one quarter of the total capital costs to the entire industry for treating FGD wastewater with CP+LRTR, but they would still amount to approximately one fifth if TVA's estimated capital costs were used. Both instances represent disproportionately high costs, as compared to the rest of the industry. Furthermore, while the baseline IPM run discussed below used costs of

[8] For similar reasons, Section 301(c) of the Act does not restrict EPA's authority to establish a subcategory or BAT for that subcategory based on costs. EPA interprets the statute to mean, just as in the case of the variance provided under Section 301(n), that the variance provided in Section 301(c) does not govern or control the decisions EPA makes in establishing effluent limitations guidelines under Section 304(b). Instead, it provides flexibility in those guidelines after they are promulgated. Section 301(c) does not negate the statutory factors and reasonableness of EPA's determination of BAT (or subcategory) thereof.

the 2015 rule (i.e., CP+HRTR), which are somewhat higher than those for this final rule, these costs were projected to result in reduction of Cumberland's operations by 96 percent and partial retirement of the plant in order to meet the 2015 rule requirements.

Voluntary incentives program

EPA disagrees with one commenter who claims that the voluntary incentives program (VIP) allows the Agency to "avoid" requiring the BAT standard. For the reasons explained in the preamble, EPA selected chemical precipitation plus low residence time biological treatment as the generally applicable BAT for electric generating units discharging pollutants found in FGD wastewater. As part of BAT, rather than as a "substitute" as the commenter claims, EPA also established a VIP that gives plants the option of being bound by more stringent membrane filtration-based limitations. EPA specifically found that, at this time, membrane filtration is not technologically available on an industry-wide basis, but might in the future become available on a site-specific basis. EPA also disagrees with the commenter that plants can "decide whether or not to comply" with the final limits. For plants that opt into the VIP, meeting the more stringent VIP limits is not "voluntary," but rather would be the required BAT technology-based limits for those plants.

Authority for extended compliance dates

Some commenters argued that EPA lacks authority under the Clean Water Act to establish a VIP with compliance deadlines beyond three years from the date of promulgation of the final rule. EPA disagrees. The statute has no deadline for BAT effluent limitations established after 1989. EPA's view that the statute does not prohibit compliance deadlines beyond three years has clear support in a recent decision by the U.S. Court of Appeals for the Fifth Circuit, which held that the Clean Water Act's requirement in 33 U.S.C. §§ 1311(b)(2)(C), (D), and (F) that effluent limitations be met no later than three years after promulgation applies only to initial BAT limitations, not revisions of such effluent limitations. *Clean Water Action v. Pruitt*, 936 F.3d 308, 316 (5th Cir. 2018). As the Court stated,

> The "in no case later than three years" language in the provision is modified by the deadline "and in no case later than March 31, 1989." Petitioners' reading of the statute is absurd, as it is impossible to require compliance with BAT effluent limitations *both* within three years of the 2015 Rule *and* by March 31, 1989. EPA's reading of the text accords the language its natural meaning: the initial BAT effluent limitations were to be complied with as expeditiously as practicable, but in no case later than three years after promulgation, with a final compliance date of March 31, 1989 at the latest. Regulated parties had to comply with EPA's initial BAT effluent limitations either within three years of promulgation or by March 31, 1989 – whichever came first. This reading is supported by § 1311(d), which requires EPA periodically to review BAT limitations, including after 1989, but contains no such compliance deadline. *See* 33 U.S.C. § 1311(d).

Clean Water Action v. Pruitt, 936 F.3d at 316. Because the compliance deadlines in Sections 301(b)(2)(C), (D), and (F) of the Clean Water Act only apply to effluent limitations guidelines that were established prior to the outside dates specified in those provisions, they do not apply to effluent limitations guidelines established in 2020.

EPA also disagrees with commenters who claim that the existence of authority under Clean Water Act section 301(k), 33 U.S.C. § 1311(k), for EPA to provide an extended compliance date of two years for "innovative" technologies means that EPA lacks authority to extend BAT compliance deadlines beyond three years after promulgation. Section 301(k) applies to an innovative technology that results in a greater effluent reduction or that can be operated at a significantly lower cost than the selected BAT. It does not place any constraints on the time period for meeting limits based on BAT technologies specified by the rule (under this rule, there are generally applicable BAT limits that must be met by 2025, as well as BAT limits applicable to plants opting into the VIP, which must be met by 2028).

Pretreatment standards

EPA disagrees with a commenter who claimed that EPA lacks adequate support for its view that pretreatment standards are designed to ensure that wastewaters from direct and indirect industrial dischargers are subject to similar levels of treatment. Sections 301 and 307 of the Act call for categorical, technology-based treatment standards reflecting the BAT level of control. Sections 301(b)(1)(A) (BPT) and 301(b)(2)(A) (BAT), after discussing the requirements for direct dischargers, say that "in the case of a discharge into a publicly owned treatment works" or "in the case of the introduction of a pollutant into a publicly owner treatment works" "which meets the requirements of subparagraph (b) of this paragraph, shall require compliance with any applicable pretreatment requirements under section [307]" of this title. Section 307 calls for the establishment of categorical pretreatment standards for pollutants that are determined not to be susceptible to treatment by such treatment works or which would interfere with the operation of such treatment works. EPA interprets this a condition precedent for regulating a pollutant introduced to a POTW, not as the standard for the regulation. EPA's long-standing, reasonable interpretation is that a pollutant "passes through" if, on a nationwide basis, the percent of the pollutant removed by a well-operated POTW achieving secondary treatment is less than removed by the model BAT treatment system. This reflects that the indirect discharger pays rather than the public for the pollutant removal. Removal credits are available to indirect dischargers to account for the pollutant removal at a POTW as long as the combined removal of pollutants by the indirect discharger and POTW equals what is required by direct dischargers and revising the standard does not prevent compliance with sludge requirements under CWA section 405. *See* 40 C.F.R. part 403. Because the reference to indirect dischargers, i.e., discharges to pretreatment works, is contained in the subparagraphs of Section 301 calling for control at the BPT or BAT level, EPA interprets the statute to require the same level of control for both direct and indirect dischargers. This interpretation is supported further by Section 307(c), which is the new source performance standard analogue for indirect dischargers. That section says:

> In order to insure that any source introducing pollutants into a publicly owned treatment works, which source would be a new source subsection to section 1316 of this title if it were to discharge pollutants, will not cause a violation of the effluent limitations established for any such treatment works, the Administrator shall promulgate pretreatment standards for the category of sources simultaneously with the promulgation of standards of performance under section 1316 of this title or equivalent category of new sources.

EPA has implemented the Act in a manner that requires technology-based effluent limitations and standards for direct and indirect existing and new sources (taking into account the ability of POTWs to treat certain pollutants) since its inception. The Supreme Court early on confirmed EPA's approach. In *Chem. Mfrs. Ass'n v. NRDC*, 470 U.S. 116, 119 (1985), the Supreme Court stated:

Indirect dischargers—those whose waste water passes through publicly owned treatment plants—are similarly required to comply with pretreatment standards promulgated by EPA under § 307 of the Act, 33 U.S.C. § 1317(b), for pollutants not susceptible to treatment by sewage systems or which would interfere with the operation of those systems. Relying upon legislative history suggesting that pretreatment standards are to be comparable to limitations for direct dischargers, see H.R.Rep. No. 95–830, p. 87 (1977), U.S.Code Cong. & Admin.News 1977, 4326, 4462, and pursuant to a consent decree,[4] EPA has set effluent limitations for indirect dischargers under the same two-phase approach applied to those discharging waste directly into navigable waters. Thus, for both direct and indirect dischargers, EPA considers specific statutory factors[5] and promulgates regulations creating categories and classes of sources and setting uniform discharge limitations for those classes and categories.

For the reader's convenience here are the footnotes in the Supreme Court's opinion:

4 Lawsuits by NRDC resulted in a consent decree placing EPA under deadlines for promulgating categorical pretreatment standards based on BPT and BAT criteria. *NRDC v. Train,* 8 ERC 2120, 6 Env.L.Rep. 20588 (DC 1976), modified *sub nom. NRDC v. Costle,* 12 ERC 1833, 9 Env.L.Rep. 20176 (DC 1979), modified *sub nom. NRDC v. Gorsuch,* No. 72–2153 (Oct. 26, 1982), modified *sub nom. NRDC v. Ruckelshaus,* No. 73–2153 (Aug. 2, 1983), and 14 Env.L.Rep. 20185 (1984). In the 1977 amendments to the Act, Congress sanctioned this approach to establishing pretreatment standards for indirect dischargers. *Environmental Defense Fund, Inc. v. Costle,* 205 U.S.App.D.C. 101, 115–116, 636 F.2d 1229, 1243–1244 (1980).

5 The factors relating to the assessment of BAT standards, set out in § 304(b)(2)(B) of the Act, include the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, the cost of achieving effluent reduction, and non-water quality environmental impacts. 33 U.S.C. § 1314(b)(2)(B).

In *Envtl. Def. Fund v. Costle*, the D.C. Circuit stated, "Pretreatment standards are similar to BAT effluent limitations, BADCT performance standards, and other controls prescribed by the statute in that they are 'technology-based.' They differ from these other controls principally in that they regulate 'indirect' discharges into sewers leading into municipal treatment plants rather than 'direct' discharges into receiving waters." 636 F.2d 1229, 1235 n.15 (D.C. Cir. 1980). Thus, for both direct and indirect dischargers, EPA considers specific statutory factors and promulgates regulations creating categories and classes of sources and setting uniform discharge limitations for those classes and categories. *See also Reynolds Metals Co. v. EPA*, 760 F.2d 549, 553 (4th Cir. 1985) ("The legislative history indicates that pretreatment standards are analogous to the standards for direct dischargers, *i.e.* the combined treatment of wastewater by an indirect discharger and the POTW should achieve the same level of pollution removal as would be realized if the industrial source were treating wastewater and then directly discharging it.") (citing H.R.Conf.Rep. No. 830, 55th Cong., 1st Sess. 87, *reprinted in* 1977 U.S. Code Cong. & Ad. News 4326, 4424, 4462.)); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 249 (5th Cir. 1989) ("PSES are equivalent to BAT standards.") (citing 1977 Leg. Hist. at 271, 342, 403).

Compliance with the Endangered Species Act

EPA disagrees with some commenters' assertion that the Agency was required by Section 7(a)(2) of the Endangered Species Act (ESA) to consult with the Fish and Wildlife Service and National Marine Fisheries Service (the Services) prior to promulgating this technology-based rule, or that EPA is in violation of Section 7(d) for not doing so. EPA is not required to consult on this action because the Agency lacks discretion to consider or account for effects on species when issuing a technology-based rule under sections 301(b), 304(b), 306 and 307(b) of the Clean Water Act. The Services' regulations make clear that ESA "Section 7 and the requirements of this part apply to all actions in which there is *discretionary* Federal involvement or control." 50 C.F.R. § 402.03 (emphasis added). Under the ESA, an Agency is not required to consult where there is no discretion to act to benefit the species at issue. Under *Karuk Tribe of Cal. v. U.S. Forest Service*, 681 F.3d 1006 (9th Cir. 2012), a federal agency has a duty to consult under the ESA Section 7 only when (1) the "federal agency affirmatively authorized, funded, or carried out" an activity; and (2) in affirmatively authorizing, funding, or carrying out the activity, the federal agency "has some discretion to influence or change the activity for the benefit of a protected species." *Karuk Tribe*, 681 F.3d at 1021; *see also Turtle Island Restoration Network v. Nat'l Marine Fisheries Serv.*, 340 F.3d 969, 974-75 (9th Cir. 2003); *Ground Zero Ctr. for Nonviolent Action v. U.S. Dep't of the Navy*, 383 F.3d 1082, 1092 (9th Cir. 2004) (no duty to consult where Navy lacked discretion to cease missile operations for the protection of listed species). If an agency cannot influence a private activity to benefit a listed species, there is no duty to consult because "consultation would be a meaningless exercise." *Sierra Club v. Babbitt*, 65 F.3d 1502, 1508-09 (9th Cir. 1995) (no duty to consult for approval of logging roads where, pursuant to a prior right-of-way agreement, BLM retained discretion over only three specified criteria, none of which related to protecting listed species); *Envtl. Prot. Info. Ctr. v. Simpson Timber Co.*, 255 F.3d 1073, 1081-82 (9th Cir. 2001) (no duty to reinitiate consultation for previously issued permits where Fish and Wildlife Service lacked discretion to add protections for newly listed species). The relevant question is whether the agency could influence a private activity to benefit a listed species, not whether it must do so. *Turtle Island*, 340 F.3d at 977.

The Clean Water Act establishes a two-step approach for accomplishing its ambitious goals. First, the Act requires application of effluent limitations for point source dischargers based on technology-based effluent limitations and standards. Clean Water Act sections 301(b)(1)(A), 301(b)(2)(A), and 301(b)(2)(E), 306, 307(b); 33 U.S.C. §§ 1311(b)(1)(A), 1311(b)(2)(A), 1311(b)(2)(E), 1316, 1317(b) and 40 C.F.R. § 122.44(a)(1). Second, where those technology-based effluent limitations are not sufficient to meet applicable water quality standards, the Act requires any more stringent effluent limitations necessary to meet applicable water quality standards under Clean Water Act section 301(b)(1)(C), 33 U.S.C. 1311(b)(1)(C), and 40 C.F.R. § 122.44(d). See *PUD No. 1 of Jefferson Cty. v. Wash. Dep't of Ecology,* 511 U.S. 700, 704 (1994). The first step sets a technology-based floor to achieve effluent reductions that represent what is the best available technology economically achievable[9] and does not consider water quality-related impacts of those controls. The second step addresses additional controls where necessary to meet water quality standards, including human health, aquatic life and aquatic-dependent wildlife. Unlike the water quality-based provisions, in the technology-based provisions of the Act, such as in issuing effluent limitations guidelines, EPA determines what technology is available to control effluent discharges. Under the water-quality-based provisions of the Act, EPA determines what is necessary to protect designated uses that are part of the applicable water quality standards. Designated uses can include the protection of critical habitat for endangered or threatened species. Where appropriate, EPA consults when it establishes water quality standards or water quality-based effluent limitations in an EPA-issued NPDES permit. However, EPA's long-standing legal position, when the Agency first addressed the question of whether Section 7 applies to establishment of technology-based effluent limitations and standards under the Act, in the context of promulgating 1998 revisions to the ELGs for the Pulp, Paper, and Paperboard Industry, 63 Fed. Reg. 18504 (Apr. 15, 1998), has been that Section 7 does not apply, for the reasons explained below.

EPA's longstanding legal position is based on the language of the Act's technology-based provisions and is supported by relevant legislative history, which make clear that the limitations and standards in the final rule must be set independently of their effect on water quality or other benefits (including benefits to protected species or critical habitat).[10] These limitations and standards are established based upon the performance of specified levels of pollution control technology that is available and economically achievable, based on consideration the factors

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[9] Or that reflect best conventional technology for conventional pollutants, or best available demonstrated control technology for new sources.

[10] *See* 33 U.S.C. §§1311(b), 1314(b); 118 Cong. Rec. 33696 (1972), *A Legislative History of the Water Pollution Control Act Amendments of 1972*, 93d Cong., 1st Sess. (Comm. Print 1973), at 170 (Congress sought to "avoid imposing on the Administrator any requirement to consider the location of sources within a category or to *ascertain water quality impact of effluent controls*, or to determine the economic impact of controls on any individual plant in a single community.") (emphasis added). *See also Weyerhaeuser Co. v. Costle*, 599 F.2d 1011, 1042 (D.C. Cir. 1978) (Impact on receiving water quality not a factor in setting technology-based effluent limitations guidelines and standards).

specified in section 304(b) of the Act, 33 U.S.C. § 1314(b), related to best available technology economically achievable. These factors are limited to "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate." This means that even though a particular discharge can affect the quality of receiving water (and in turn affect listed species or designated critical habitat), EPA lacks discretion to establish the technology-based limitations and standards in this nationally applicable rulemaking based on consideration of the effects of that discharge on particular waterbodies. In other words, EPA's discretion to establish limitations based on a technology is limited to considering the factors contained in Clean Water Act sections 301, 304, and 306 and finding that the technology is both available and economically achievable. Under the Act, any limitations more stringent than those authorized based on technology-based factors in order to provide additional protection of the quality of receiving waters (including protection to listed species or designated critical habitat associated with such quality) may only be imposed outside this rulemaking in the permitting process based on the water quality-based provisions of the Act. *See* 33 U.S.C. §§ 1311(b)(1)(C) and 1313(c).

While EPA has considerable discretion to consider the technology-based factors in setting effluent limitations guidelines and standards (and how much weight to accord those factors), those section 304(b) and 306 factors do not include impacts to aquatic life or aquatic-dependent wildlife such as effects to listed species or designated critical habitat associated with quality of receiving waters. *See* footnote 2, above. Congress was impatient with the pace of progress in reducing water pollution under the prior legislation based on a water quality-based approach and embarked on the technology-based approach in order to speed progress in reducing pollution by requiring as a floor technologies that reflect best available technology economically achievable in light of the factors specified in section 304(b) and 306, abandoning concerns about receiving water impacts when issuing technology-based rules. *See Weyerhaeuser Co.*, 599 F.2d at 1042. *See also Am. Frozen Food Inst. v. Train*, 539 F.2d 107, 115 (D.C. Cir. 1976) ("However, the Federal Water Pollution Control Act Amendments of 1972 are not mere amendments to previous control attempts. Preceding pollution control measures were fundamentally designed to determine what lakes and streams had become polluted beyond toleration and then to locate the particular polluters and suppress the discharges that were causing the condition. Determination of which polluter caused what pollution proved over the years to be an impractical task. . . . By 1972 Congress determined upon a wholly new approach."). As described in these cases, EPA was to establish expeditiously technology-based limits on discharges without considering the site-specific effects of the limitations on the receiving waters.

While section 304(b) states that factors to be considered include "such other factors as the Administrator deems appropriate," that language must be read within the context of the section and cannot override the technological availability and economic achievability factors. It is a fundamental principle of statutory interpretation that Congress "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes." *Whitman v. Am. Trucking Associations, Inc.*, 531 U.S. 457, 468 (2001) (citing *MCI Telecommunications Corp. v. Am. Telephone & Telegraph Co.,* 512 U.S. 218, 231 (1994); *FDA v. Brown & Williamson Tobacco Corp.,* 529 U.S. 120, 159-160 (2000)). Commenters' arguments ultimately fail upon this principle. The "other factors" language cannot be set to upend the fundamental technology-based nature of these provisions. In *Whitman v. American Trucking Associations, Inc.*, the Supreme Court held that cost was not a factor in making certain decisions under the Clean Air Act. Rejecting arguments that the Clean Air Act "§ 109(b)(1)'s terms 'adequate margin' and 'requisite' leave room to pad health effects with cost concerns," the Court held "we find it implausible that Congress would give to the EPA through these modest words the power to determine whether implementation costs should moderate national air quality standards." *Id.* at 468-469 (citing *Christensen v. Harris County,* 529 U.S. 576, 590, (2000) (SCALIA, J., concurring in part and concurring in judgment)). In *MCI Telecommunications Corp. v. Am. Telephone & Telegraph Co.,* the Supreme Court found it "highly unlikely that Congress would leave the determination of whether an industry will be entirely, or even substantially, rate-regulated to agency discretion—and even more unlikely that it would achieve that through such a subtle device as permission to 'modify' rate-filing requirements." 512 U.S. at 231. And in *FDA v. Brown & Williamson Tobacco Corp.*, the Supreme Court further emphasized that "[i]n determining whether Congress has specifically addressed the question at issue, a reviewing court should not confine itself to examining a particular statutory provision in isolation. The meaning—or ambiguity—of certain words or phrases may only become evident when placed in context." 529 U.S. at 133 (citing *Brown v. Gardner,* 513 U.S. 115, 118 (1994) ("Ambiguity is a creature not of definitional possibilities but of statutory context"); *Davis v. Michigan Dept. of Treasury,* 489 U.S. 803, 809 (1989) ("It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme.")).

Applying those principles here, the "other factors" language in Section 304(b) does not transform the technology-based requirements of the Clean Water Act into water-quality based regulations. Congress intended EPA to establish the requirements of this regulation based on the performance of available and economically achievable technologies without regard to effects on receiving water quality (or those attended effects on species). In other words, the limits and standards in this rule are established by looking only at characteristics of the industrial dischargers, not the characteristics or quality of the receiving water or the impact of the discharge on such water quality. In contrast, water quality-based effluent limits are established with an outward view, away from the discharger, with an eye toward impacts to the waterbody. The recent decision reviewing portions of the 2015 steam electric rule, *Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999, 1027 (5th Cir. 2018), elaborated on the requirements of the technology-based provisions of the Act:

> The Act requires ELGs to be based on technological feasibility rather than on water quality. *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 927 (5th Cir. 1998) (*citing E.I. du Pont de Nemours & Co. v. Train*, 430 U.S. 112, 130-31, 97 S.Ct. 965, 51 L.Ed.2d 204 (1977); *Am. Petroleum Inst. v. EPA,* 661 F.2d 340, 343-44 (5th Cir. 1981)). That is, the Administrator must "require industry, regardless of a

> discharge's effect on water quality, to employ defined levels of technology to meet effluent limitations." *Am. Petroleum Inst.*, 661 F.2d at 344; *see also Tex. Oil & Gas*, 161 F.3d at 927 (ELGs are "technology-based rather than harm-based" insofar as they "reflect the capabilities of available pollution control technologies to prevent or limit different discharges rather than the impact that those discharges have on the waters"). . . . The D.C. Circuit accurately described this aspect of the Act's scheme as "technology-forcing," meaning it seeks to "press development of new, more efficient and effective [pollution-control] technologies." *NRDC v. EPA*, 822 F.2d 104, 123 (D.C. Cir. 1987) (*"NRDC I"*); *see also, e.g., NRDC v. EPA*, 808 F.3d 556, 563-64 (2nd Cir. 2015) ("*NRDC II*") (describing ELG scheme as "technology-forcing, meaning it should force agencies and permit applicants to adopt technologies that achieve the greatest reductions in pollution") (citing *NRDC I*).

While not relevant to the establishment of BAT limitations in this rule, the fact that section 304(b)(1)(B) lists as a factor in setting *BPT* limitations "the total cost of application of technology in relation to the effluent reduction benefits to be achieved" does not expand in even that context EPA's discretion to base limitations on water quality impacts. *See E. I. du Pont de Nemours & Co. v. Train*, 430 U.S. 112, 130 (1977) (noting that "[t]he Conferees agreed upon this limited cost-benefit analysis in order to maintain uniformity within a class and category of point sources subject to effluent limitations, and to avoid imposing on the Administrator any requirement to consider the location of sources within a category *or to ascertain water quality impact of effluent controls*, or to determine the economic impact of controls on any individual plant in a single community.") (citing118 Cong.Rec. 33696 (1972), Leg.Hist. 170) (emphasis added); *see also Am. Frozen Food Inst. v. Train*, 539 F.2d 107, 121 (D.C. Cir. 1976) (determination of BPT is not to be based upon the quality of the receiving waters); *Ass'n of Pacific Fisheries v. EPA*, 615 F.2d 794, 805 (9th Cir. 1980) (EPA is not required to demonstrate the incremental effect on receiving water quality); *Consolidated Coal Co. v. Costle*, 604 F.2d 239, 245 (4th Cir. 1979) (receiving water quality is not a basis for setting BPT limits or granting Fundamentally Different Factors variances); *Weyerhaeuser Co. v. Costle*, 599 F.2d 1011, 1028, 1042 (D.C. Cir. 1978) (impact on receiving water quality not a factor). This means that even if a particular effluent limitation or standard were thought to be absolutely necessary to protect species, EPA could not promulgate it under the statute based on consideration of effects to water quality/listed species; rather, the Agency's discretion is cabined to basing limitations in this rulemaking on measures that are technologically available and economically achievable. To read section 304(b)'s "other factors" language to include water quality and listed species impacts would swallow the technology factors and upend the statutory scheme Congress carefully crafted calling for nationally applicable technology-based regulations and supplemental controls on a permit-by-permit basis where necessary to protect the quality of receiving waters.[11]

[11] Commenters' citation to a Clean Air Act case, *Am. Fuel & Petrochemical Mfrs. v. EPA*, 937 F.3d 559, 597 (D.C. Cir. 2019), in support of their argument that the CWA provides EPA with the requisite discretion to consult in this case is misplaced because, in the that case, the Court found that EPA was statutorily required to "consider six factors, one of which allows the EPA to modify [fuel] volumes based on environmental considerations, such as

Commenters' argument that the exercise of discretion in the rule is apparent from EPA statements in the record as well as its decision to establish a Voluntary Incentives Program (VIP) misunderstands the type of discretion that must exist for the section consultation 7 requirement to be triggered. In particular, EPA's explanation, echoed in the caselaw, is that it has considerable discretion to weigh the technology-based statutory factors enumerated in sections 301(b)(2)(A) and 304(b)(2)(B) (*e.g*., technological availability, economic achievability, cost, non-water quality environmental impacts). The discretion does not extend to consider entirely separate factors from the ones set forth in the statute (*e.g*., impacts to listed species/designated critical habitat, benefits). *See National Association of Homebuilders v. EPA*, 551 U.S. 644 (2007). Similarly, EPA's decision to establish a VIP in this rule was made within the confines of the statutory criteria and factors for establishing technology-based standards. EPA has determined that the technologies on which the VIP program are based may be technologically available and economically achievable on a site specific basis by 2028. This determination was made based on EPA's consideration of the factors listed in CWA section 304(b). Thus, EPA's creation of this program does not open a floodgate to consideration of wholly different factors such as water quality impacts or impacts to endangered species/designated critical habitat.

EPA's decision not to consult on ELG rules, including this rule one, under the ESA is supported by the Supreme Court's decision in *National Association of Homebuilders v. EPA*, 551 U.S. 644 (2007). In that case, the Supreme Court held that the no-jeopardy duty under the ESA only applied to discretionary actions and did not apply to the permitting transfer approval which was mandatory under the Clean Water Act once the specified triggering criteria were met. Although the duties under the Clean Water Act and the ESA were both stated in mandatory terms, the Court found that 50 C.F.R. § 402.03 appropriately construed the ESA to require the no-jeopardy assessment only if the agency action was discretionary, and there was no basis for an implicit repeal of the permitting transfer approval requirement by imposing the additional requirement of a no-jeopardy duty to obtain such approval. *Nat'l Ass'n of Homebuilders v. EPA*, 551 U.S. at 663-66. In discussing the CWA section 402(b)'s National Pollutant Discharge Elimination System permitting transfer requirements, 33 U.S.C. § 1342(b), the Court stated:

> While the EPA may exercise some judgment in determining whether a State has demonstrated that it has the authority to carry out section 402(b)'s enumerated statutory criteria, the statute clearly does not grant it the discretion to add another entirely separate prerequisite to that list. Nothing in the text of section 402(b)

concerns about wetland conversion, wildlife habitat, and water quality." In contrast, the Clean Water Act provisions at issue include no such factors. In fact, the sole reference to environmental impacts cuts in the other direction, because Congress only permitted EPA to consider "*non-water quality* environmental impacts." *See Weyerhaeuser Co. v. Costle*, 590 F.2d at 1053 n.68 ("The House version of section 304 used the bare term 'environmental impacts.' The conference version's shift to 'non-water quality environmental impacts (including energy requirements)' reflected a carefully crafted alternative . . . [A]s we have discussed, the Act intended to exclude consideration of receiving water quality completely. If the House provision had been retained, it would have been natural to construe 'environmental impacts' as including impacts on water quality. That construction would have suggested that receiving water quality was relevant, since environmental impact on water varies with the nature of the receiving water. By specifying 'non-water quality environmental impacts,' Congress kept receiving water quality considerations from being brought into play.") (citation omitted).

> authorizes the EPA to consider the protection of threatened or endangered species as an end in itself when evaluating a transfer application.

Nat'l Ass'n of Home Builders v. EPA, 551 U.S. at 672. By analogy to the provisions of the Clean Water Act at issue in this rulemaking, the ESA provisions do not impliedly amend or repeal the Clean Water Act provisions requiring EPA to look solely at the technology-based factors specified in the Clean Water Act. As the cases above demonstrate, Congress did not intend for environmental impacts such as impacts to listed species to be an end in itself in the establishment of technology-based regulations. Impacts to species are related to water quality impacts, which under the statute, EPA lacks discretion to consider in this rulemaking. These water quality impacts are considered at the water quality-based effluent limitation stage, not when establishing technology-based effluent limitations guidelines and standards.

Indeed, if EPA were to establish technology-based requirements based upon water quality-related impacts, Congress would not have needed to require, through section 301(b)(1)(C) of the Act, that dischargers meet any more stringent limitations necessary to meet water quality standards on a case-by-case basis. The structure of the Act indicates that Congress viewed the establishment of water quality-based controls as being appropriate on a case-by-case basis, taking into account the particular nature of the discharge and the water quality standards for the receiving waterbody. The commenters' view would turn this approach on its head, effectively mandating the establishment of water quality-based requirements on a national basis, without regard to site-specific considerations viewed by Congress as integral to establishing appropriate water quality-based controls and would run directly counter to Congress's clear intent that the national standards not be based on considerations of water quality. Such an approach would, therefore, fundamentally transform the structure and operation of the Clean Water Act and contradict Congress' attempt in the 1972 Amendments to establish a technology-based floor for point source dischargers, to be supplemented by imposition of water quality-based requirements where necessary on a permit-by-permit basis. EPA's approach of protecting aquatic life and aquatic-dependent wildlife (including threatened and endangered species) through the water quality standards and permitting process, by contrast, ensures EPA implements the technology-based provisions of the Clean Water Act consistent with law, while also ensuring consideration of effects to listed species and measures to protect them where the Agency has discretion under the Clean Water Act to do so.[12]

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[12] EPA considers impacts to protected species and designated critical habitat during the water quality standards review process under CWA section 303(c), 33 U.S.C. § 1311(c). *See* Memorandum of Agreement Between the Environmental Protection Agency, Fish and Wildlife Service and National Marine Fisheries Service Regarding Enhancing Coordination Under the Clean Water Act and Endangered Species Act, 66 Fed. Reg. 11202, 11213 (Feb. 22, 2001). Where EPA is permitting authority, it complies with Section 7. *See* 40 C.F.R. 122.49(c). While State-issued NPDES permits are not federal actions and therefore not subject to Section 7 of the ESA, they are nonetheless required to ensure compliance with applicable water quality standards where, as noted above, effects to listed species are considered through the section 7 consultation process. *See* 33 U.S.C. § 1311(b)(1)(C) and 40 C.F.R. 122.44(d).

Public participation in the rulemaking

EPA disagrees with commenters who argued that EPA failed to allow for adequate public participation in this rulemaking. EPA's actions with respect to public participation satisfied both the Clean Water Act and the Administrative Procedure Act.

The proposed rule was published in the Federal Register on November 22, 2019, and the public comment period closed on January 21, 2020, thereby providing a formal 60-day comment period for members of the public to submit written comments on the proposed rule. The comment period was adequate in this case, particularly considering that the vast majority of issues involved in this rulemaking are not new but have been presented to the public throughout the Agency's work to update the Steam Electric ELGs, which began in 2010. Furthermore, while this comment period was over the holidays as some commenters pointed out, generally the holidays do not mean that work cannot proceed for the entire period between November 22 and January 21.

Because of the long history of this rulemaking, the issues involved related to the two wastestreams that are the focus of the final rule (bottom ash transport (BA) water and flue gas desulfurization (FGD) wastewater) are not new to commenters. Information about the steam electric industry's discharges and main treatment technologies for controlling these discharges has been available since at least 2010, when EPA's detailed study of the steam electric industry was published. Moreover, this rulemaking is an extension of an earlier rulemaking that concluded in 2015.[13] The same commenters who requested an extension of the public comment period in this rulemaking had the opportunity, and took advantage of such opportunity, to participate in the 2015 rulemaking. Through court filings and postings on EPA's website, the public has been aware of the reconsideration petitions that triggered the current rulemaking since early 2017, as well as the former Administrator's decision to reconsider the 2015 rule since the Summer of 2017. Furthermore, a pre-publication copy of the proposed rule was posted on EPA's website on November 4, 2019. Thus, public commenters are very familiar with the issues raised for public comment in the proposal.

Neither the Clean Water Act nor the Administrative Procedure Act specifies how long a public comment period must be. Nevertheless, the U.S. Court of Appeals for the District of Columbia has held that 30 days is the presumptive minimum comment period for rules with substantial changes. *See National Lifeline Ass'n v. FCC*, 2019 WL 405020 at *10 (D.C. Cir. February 1, 2019) ("When substantial rule changes are proposed, a 30-day comment period is generally the shortest time period sufficient for interested persons to meaningfully review a proposed rule and provide informed comment."). And, as commenters acknowledge, Executive Order 12866

[13] Indeed, this rulemaking revises only a portion of the 2015 rule and thus comparisons to the comment period for the earlier rule are misplaced. In particular, as opposed to six wastestreams addressed in the 2015 rule (FGD wastewater, BA transport water, fly ash transport water, gasification wastewater, combustion residual leachate, and legacy wastewater), this rule only pertains to FGD wastewater and BA transport water. Moreover, the 2015 rule applied to both existing and new sources, while this rule applies only to existing sources.

encourages, in most cases, Agencies to establish a comment period of at least 60 days. The comment period in this rulemaking satisfied these directives.

EPA chose not to extend the comment period beyond January 21, 2020, because it had to balance the need for public participation along with the fact that steam electric power plants were required to comply with the 2015 rule on November 1, 2020. In order to finalize the rule before that date, and with time for steam electric power plants and permitting authorities to consider the implications of the final rule, EPA determined it was necessary to maintain the 60-day comment period. The fact that, during the comment period, EPA received more than 7,400 public comment submissions from private citizens, industry members, technology vendors, government entities, environmental groups, and trade associations on the rule (including hundreds of pages of comments from the organizations requesting extensions of the comment period), and has responded to all of them, further demonstrates that EPA provided an adequate opportunity for public participation. *See Am. Farm Bureau Federation v. EPA*, 984 F. Supp. 2d 289, 333-34 (M.D. Penn. 2013) (holding that a 45-day comment period was sufficient where the agency action marked a multi-year, open effort and plaintiffs submitted comments raising many issues, to which EPA responded).

EPA also held an online public hearing during the public comment period on December 19, 2019. During the hearing, which was attended by 110 people, EPA staff working on the rulemaking heard directly from 32 members of the public. EPA did not receive comments related to specific concerns with access to the public hearing. EPA notes that online hearings can provide for participation by some who otherwise could not attend an in-person hearing due to travel or other limitations. This is a nationwide rule and people all over the country have demonstrated an interest in it. Holding an in-person hearing in Washington, DC would have had the disadvantage of limiting participation only to those people who could travel to this location. Some commenters claim that the online hearing denied them the important opportunity of face-to-face contact with decisionmakers. But EPA never denied any requests for an in-person meeting during the rulemaking; and, in fact, following publication of the proposed rule, EPA did meet face-to-face with all interested groups, including industry groups and environmental groups, that requested a meeting.

EPA's decision to hold an online public hearing comports with the Clean Water Act and the Administrative Procedure Act. Section 307(b) of the Clean Water Act, 33 U.S.C. 1317(b)(1), requires that EPA afford an opportunity for public hearing on proposed regulations establishing pretreatment standards.[14] The statute does not specify that the hearing must be in-person. Despite claims by some commenters, EPA's online public hearing did not violate the Act's requirement that "[p]ublic participation in the development, revision, and enforcement of any regulation, standard, effluent limitation, plan, or program established by the Administrator or any State under this Act shall be provided for, encouraged, and assisted by the Administrator and the States." 33 U.S.C. § 1251(e). The general Administrative Procedure Act requirement for notice-

[14] EPA estimates that there are three steam electric power plant subject to the final rule that discharge pollutants in FGD wastewater or BA transport water indirectly to a POTW.

and-comment rulemaking does not require a face-to-face public hearing. As the U.S. District Court for the District of Columbia recently found, "Although the EPA must act to promote public participation, it has vast discretion as to the *methods* it uses to promote participation, and 'a court would have no meaningful standard against which to judge the agency's exercise of discretion.'" *City of Dover v. U.S. Envtl. Protection Agency*, 956 F.Supp.2d 272, 283 (D.D.C. 2013) (quoting *Heckler v. Chaney*, 470 U.S. 821 (1985) (emphasis in original). EPA's choice to conduct an online public hearing, as well as hold a 60-day comment period, was squarely within EPA's discretion.

Like the Clean Water Act, EPA's public participation regulations codified in 40 C.F.R. Part 25 do not specify that hearings must be conducted in person. In fact, one of the stated objectives for the regulations is "[t]o use *all feasible means* to create opportunities for public participation, and to stimulate and support participation." 40 C.F.R. § 25.3(c)(7) (emphasis added). There is nothing in the regulations suggesting that hearings must be conducted in person. Indeed, the preamble to Part 25 states that the regulations should provide "maximum flexibility and discretion" to implementing agencies and that implementing agencies should have the "freedom to tailor their programs to specific local, regional, or Statewide needs." And, while EPA officials might have envisioned that hearings under Part 25 would be conducted in-person, as discussed above, there are public participation advantages to online hearings that might not have been understood at the time the regulations were originally drafted. EPA published guidance in 2019 in connection with water quality standards, which recognized that 40 C.F.R. § 25.5 became effective prior to the common use of technology such as computers and the Internet, and identified opportunities and options to use technology consistent with the relevant public hearing requirements in § 25.5. *Modernizing Public Hearings for Water Quality Standards Consistent With 40 CFR 25.5:* https://www.epa.gov/sites/production/files/2019-05/documents/modernizing_public_hearings_for_wqs_decisions_consistent_with_40_cfr_25.5_.pdf.

EPA's consideration of public comments

One commenter claims that EPA has, generally, failed to assess public comments submitted on its proposals. EPA actions other than the one at issue here are outside the scope of this rulemaking. With respect to this rule, EPA disagrees with comments suggesting that EPA did not assess public comments. EPA also disagrees with the commenter who suggested that certain public comments be afforded less weight than other public comments. In this rulemaking, EPA has carefully considered the comments received in the docket, including data and information that weighs on the statutory factors to be considered in establishing this type of rule. EPA also informs itself of data and information to fulfill applicable Executive Orders (see Section XV of the final rule preamble). EPA has endeavored to examine the data and information relevant to this rulemaking, but because obtaining perfect information is not possible, courts have held that EPA can regulate based on imperfect information. *See, e.g., Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 934 (5th Cir. 1998) (in upholding a challenge to EPA's effluent guidelines for coastal facilities that used information about older facilities to represent pre-1980 wells, the court stated: "Although the exclusion of pre-1980 facilities may have had some effect on the precision of the

EPA's analysis of the age factor, we cannot agree with Texas Petitioners that this exclusion rose to the level of arbitrary and capricious agency action. An agency's choice to proceed on the basis of 'imperfect information' is not arbitrary and capricious unless 'there is simply no rational relationship' between the means used to account for any imperfections and the situations to which those means are applied.") (quoting *Am. Iron & Steel Inst. v. EPA*, 115 F.3d 979, 1004 (D.C. Cir. 1997). EPA's responses to public comments in the preamble describe how the Agency considered the statutory factors and public comments in establishing the final rule.

One commenter also submitted comments regarding court decisions on EPA actions unrelated to the current action. Such comments are outside the scope of this rulemaking. EPA notes that this rule was promulgated using typical notice and comment procedures under the Administrative Procedure Act (section 553(c)) and is, therefore, distinguishable from some of the cases cited by the commenter.

2 Scope and Applicability

No comment excerpts were received on this topic.

3 Regulatory Options – General

Some commenters asserted that EPA's decision to reconsider the 2015 rule was solely based on the 2015 requirements being "overly stringent" or due to "large capital costs." EPA disagrees, as its reconsideration of the 2015 rule evaluated changes in the industry and the development of technologies since the 2015 ELGs were finalized. For FGD wastewater this included evaluating more affordable treatment technologies installed in the industry and for bottom ash transport water this involved addressing process challenges with some treatment technologies evaluated previously.

One commenter asserted that by "redefining the term 'transport water', EPA proposes to narrow the categories of wastewater that are governed by the current effluent limitation guidelines and pretreatment standards in 40 CFR Part 423." EPA disagrees with this comment. The final rule differentiates "purge water" from "transport water" because EPA has learned that the wet bottom ash handling systems that EPA used to establish the 2015 rule's zero discharge requirements cannot operate as zero discharge systems in many cases. EPA's knowledge of how these wet ash systems operate has continued to improve since the 2015 rule and while these systems are still available and affordable, they cannot be operated to achieve zero discharge industry-wide. As described in section VII.B.2 of the preamble, the final rule addresses these process challenges by defining a new bottom ash purge water stream and allowing a purge from high recycle rate systems up to a maximum of 10 percent of the system's volume to be determined on a site specific basis by the permitting authority.

EPA agrees in part with one commenter who stated that "the adoption of . . . . subcategories is necessary to avoid the imposition of excessive compliance costs and address unique operating conditions of affected EGU sources." See Section VII.C of the preamble for EPA's rationale for establishing the subcategories and the technology bases selected. For the low utilization and units permanently ceasing coal combustion subcategories, EPA relies on costs, non-water quality environmental impacts, and other factors as the Administrator deems appropriate.

EPA agrees with the commenter who asserted that defining "BATW purge sent to the FGD scrubber [as] not subject to bottom ash (BA) transport water limits prior to commingling with other water" would "encourage reuse of BATW purge water." The final rule includes the following in the definition of bottom ash transport water at 423.13(k)(1)(i): "when the bottom ash transport water is used in the FGD scrubber, it ceases to be bottom ash transport water, and instead is FGD wastewater." When this occurs, this wastewater is required to meet the limitations on FGD wastewater and there are no BA transport water limits prior to the scrubber.

EPA disagrees with commenter who stated that the Agency should "reaffirm the zero discharge requirements for coal ash wastewater." As described in Section VII.B of the preamble, EPA did not select zero discharge as the technology basis for either FGD wastewater or bottom ash transport water. For BA transport water, although a closed-loop system was selected as BAT for the 2015 rule and some facilities can achieve zero discharge, since the 2015 rule, EPA has become aware of operational challenges and limitations that prevent these systems from operating as fully closed-loop systems. In light of this new information, as well as the fact that these same units must comply with requirements and fast-approaching deadlines in the CCR Part A rule, the final rule establishes limitations that allow for a purge from the BA transport water treatment system. See section VII.B.2 of the preamble for details regarding selection of BAT for BATW and response to Comment Code 23 (BATW – Zero Discharge). For FGD wastewater, as described in the preamble and the Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental TDD) (EPA-821-R-20-001), EPA investigated a number of treatment technologies, including zero discharge, thermal treatment, and membrane filtration. As described in detail in the final rule preamble and the TDD, EPA does not have sufficient evidence to conclude that these systems can operate zero discharge nationwide or that they can consistently be operated zero discharge. Therefore, the final rule does not establish zero discharge limitations as BAT for reasons discussed in section VII.B.1 of the preamble. See also responses to Code 17 (FGD Wastewater – Membrane Filtration) for more details on EPA's evaluation of membrane filtration and responses to Code 15 (FGD Wastewater – CP+LRTR) regarding the final rule's limitations or expected selenium discharges for FGD wastewater.

One commenter stated that they are aware of a plant that "has spent the money to put in place technology to meet" the requirements of the 2015 rule as part of the commenter's rationale for suggesting EPA leave the 2015 rule in place. Requirements for FGD wastewater and bottom ash transport water finalized in the 2015 rule remained codified through much of 2020. As described in Section IV.D of the preamble, in September 2017, the 2015 rule earliest compliance dates for FGD and bottom ash were postponed from November 1, 2018, to November 1, 2020. Some plants may have needed to continue to take action on these 2015 rule requirements, working toward a compliance date in late 2020 or early 2021 based on the 2015 rule, as EPA was conducting its reconsideration of the rule and working to finalize this rule. These permittees may be able to seek a permit modification in light of the promulgation of the final rule.

Some commenters suggested that the proposed low utilization subcategory threshold be increased to 1.2 million megawatt-hours. One commenter made this suggestion specific to Dallman Unit 4. As described in the final rule preamble and response to Code 9b (Subcategorization – Low Utilization) EPA has modified the low utilization subcateogy in the final rule and no longer uses a generation or production threshold for eligibility. As described in the preamble, the final rule includes a capacity utilization rate threshold for the low utilization subcategory. Based on 2017 and 2018 data from the Energy Information Administration (EIA), Dallman Unit 4 is projected to run as a baseload unit with a capacity utilization rating over 50 percent and would not qualify for the low utilization subcategory in the final rule.

Some commenters suggested that the 2015 rule be re-proposed in its entirety. EPA disagrees. EPA announced it would reconsider only two waste streams from the 2015 rule—FGD and BA transport water. EPA has not proposed any other changes to the ELGs.

Regarding EPA's response to comments on technology costs and feasibility, see responses to the following codes:

- Code 14 (FGD Wastewater – Chemical Precipitation)
- Code 15 (FGD Wastewater – CP+LRTR)
- Code 17 (FGD Wastewater – Membrane Filtration)
- Code 21 (BATW – High Recycle Rate)

See DCN SE08635 for EPA's response to information submitted through comments as confidential business information.

Regarding the timing of implementation of the final rule, see section XIV.A.1 of the preamble and response to Comment Code 33 (Regulatory Implementation – Timing).

Regarding bromide see response to Comment Code 36 (Regulatory Implementation – Bromide).

See response to Code 11 (FGD Wastewater – General) for discussion of PSES.

3a Regulatory Options – Definition and Reg Language

With respect to the term "primary active wetted bottom ash system volume," EPA agrees that additional clarity and examples of some terms may be helpful and has revised paragraph 423.11(aa) of the regulatory text in several respects. This revised wording clarifies that volume is intended to include all the volume of equipment necessary to collect, transport, and settle bottom ash, as well as the equipment necessary to recirculate bottom ash transport water, with the exception of surface impoundments. Secondary equipment such as a 100% redundant system of tanks and piping would not be contained in the primary active wetted bottom ash system volume, nor would secondary equipment that was irregularly used such as maintenance tanks, even when used for occasional equalization as indicated in some comments. Rather than a required system component that must be maintained with a purge, this secondary equipment either often sits idle or could sit idle.15 The inclusion of this equipment in the primary active wetted bottom ash system volume would result in excessive purge volumes.

The revised paragraph 423.11(aa) text also explicitly excludes surface impoundment volumes, whether CCR or non-CCR volumes, from the definition of "primary active wetted bottom ash system volume." The record evidence supporting "high" recycle rate systems includes the actual, measured purges of seven remote mechanical drag and dewatering bin systems in EPRI (2016) and hypothetical, estimated purges of 21 mechanical drag and dewatering bin systems in EPRI (2018), which do not include surface impoundments.16 While EPA establishes BAT limits, it does not require compliance with the use of a specific technology to meet those limits. Although EPA identified high recycle rate systems such as remote mechanical drag systems and dewatering bin systems as the model BAT technology upon which these limits are based, nothing in this rule would prohibit plants from meeting these limits with alternate technologies that are otherwise lawful such as CCR-compliant surface impoundments that recycle their water.17 Yet allowing surface impoundment-based systems to purge 10 percent of surface impoundment volume, which is often orders of magnitude larger than tank volumes, would not be representative of the pollutant reductions that the model BAT technology can achieve. It is the combination of the reduction in overall volume and the ability to recycle the majority of that lower volume that make these technologies the best available technology as that term is used in the CWA. Furthermore, some industry comments suggest that surface impoundments reduce the need for a purge:

> "By providing spare volume that can be used quickly, cheaply, and safely, impoundments can reduce the likelihood that a plant needs to discharge maintenance purge water at all." EPA-HQ-OW-2009-0819-8325-A1

Thus, surface impoundments, like secondary tanks, can be used to temporarily manage water that might otherwise have to be discharged. With respect to the particular configuration in this comment, OG&E represents that the recirculating system has a dewatering bin, an auxiliary concrete settling tank, and a concrete recirculation tank. Assuming at face value that these concrete tanks are in fact tanks rather than concrete-lined surface impoundments, 10 percent of these volumes and any non-redundant piping may already provide an adequate purge volume to

[15] For example, a facility with redundant systems could operate two parallel systems at 50 percent rather than one system at 100%; however, EPA does not intend for both of the 100 percent redundant systems to count towards this "primary" volume in such a case.

[16] One company which met with EPA prior to proposal indicated that it might need to purge 50 percent or more of a surface impoundment system under a partial recycling option.

[17] Such a scenario is possible for at least some facilities, and the EPA notes that during site visits conducted for the 2019 proposal there was one utility which presented its plans for complete recycle of its surface impoundment water under the 2015 rule zero discharge requirement.

continue operating the existing system, and the addition of the cooling pond volume may not be necessary.[18]

With respect to the term "retired from service" the EPA has replaced this term with the new term "permanent cessation of coal combustion" as defined in paragraph 423.11(w). This term more closely aligns to the text of the CCR rule, which the EPA has clarified in the preamble of the final CCR Part A rule is intended to incorporate both retiring and repowering boilers. The EPA also agrees with comments that permits may cover entire plants, and that there are permits covering some boilers that continue operation and those should not complicate the ability of a retiring or repowering boiler to take advantage of this subcategory. Thus, the definition of this term removes the requirement that the boiler no longer be permitted to operate. The removal of this requirement makes the term self-implementing, thus also addressing comments suggesting such self-implementation is warranted. And finally, to address comments received, EPA has replaced the initial certification approach with a notice of planned participation (NOPP) approach where permittees declare their intent to permanently cease coal combustion, providing the best information available at that time, and then update the permitting authority through an annual progress report demonstrating continued progress towards that end. Thus, concerns relating to the proposed rule's initial certification timing are no longer relevant.

With respect to defining "maintenance purge water" (now "BA purge water") as low volume wastewater, EPA disagrees with the commenter that such a decision would be supported by the record. While commenters point out that the volume of purge is much smaller than previous discharges, using the small size of pollutant loadings to set BAT limitations equal to BPT limitations has been rejected for other wastestreams in this industrial sector. *See Southwestern Elec. Power Co. v. EPA*, 920 F.3d at 1026 (rejecting EPA's reliance on the relatively small size of combustion residual leachate as a reason to set BAT limitations equal to BPT limitations). Instead, EPA is declining to establish a nationwide treatment technology for BA purge water for the reasons stated in Section VII.B.2 of the preamble. Thus, BA purge water is subject to a case-by-case BPJ determination by the permitting authority.

With respect to the definitions of BA transport water and maintenance purge water, EPA agrees with these comments. First, EPA has revised the paste clause in 423.11(p) to include "FGD paste equipment cleaning water" and has made a corresponding change to the definition in 423.11(v). This would allow, for example, water generated by cleaning pugmills where paste is mixed to be covered by the clause. Second, EPA no longer uses the term "retired from service" and instead uses the term "permanently ceases coal combustion." This new term is designed to align more closely with the CCR rule, and to include repowering EGUs. Third, EPA has broadened the equipment to include all of the primary active wetted bottom ash system ("wastewater present in primary active wetted bottom ash system volume when a plant achieves permanent cessation of coal combustion") such that other tank-based equipment and piping could be included. However,

[18] Furthermore, to the extent that this or any other facility was able to come close to operating at a 10 percent purge volume but had unique site-specific factors that it had not been able to evaluate during the comment period of this proposal, that facility could apply for a fundamentally different factors variance.

this does not include the legacy wastewater remaining in surface impoundments. As explained in preamble section IV.C, the Agency intends to address legacy wastewater in a subsequent action.

Finally, EPA has adopted the term "bottom ash purge water" in place of the proposed "maintenance purge water" for 423.11(cc) because the Agency agrees with commenters that it more accurately reflects that purges can occur for non-maintenance reasons.

With respect to the differences between a purge and a discharge, EPA agrees with commenters who stated that not all purges are discharged, but disagrees that the proposed regulatory text was unclear. The final regulatory text only uses the term "purge" as part of the term "BA purge water," and otherwise refers to discharges.

With respect to recycling of wastewater, where it is employed, a power plant may comply with the final rule by achieving zero discharge through recycling. Recycling is one manner, like product substitution, that is a management practice that has served as a technology-basis in other ELGs such as *Effluent Limitations Guidelines and New Source Performance Standards for the Airport Deicing Category* (40 CFR Part 449).19 EPA acknowledges that not all power plants can achieve full recycling of their wastewater, but where a power plant is able to do so, nothing in the rule precludes the power plant from achieving compliance in this manner.

3b <u>Regulatory Options – Options Selection and Analysis</u>

EPA's analyses and presentation of the regulatory options described in the preamble and TDD does not mean that EPA failed to consider the technologies referenced by the commenter. For BA transport water, EPA considered and rejected the baseline zero discharge requirement of the 2015 rule, as discussed in Section VII.B.2 of the preamble. For FGD wastewater, EPA considered as a primary regulatory option and rejected membrane filtration, which can approach zero discharge and also considered and rejected thermal technology, as discussed in Section VII.B.1 of the preamble. EPA's analyses and thorough consideration of the range of technologies discussed in the final rule preamble and TDD is consistent with the ELG program and the CWA.

4 <u>Regulatory Options – Best Professional Judgement</u>

EPA disagrees with commenters' arguments against best professional judgement (BPJ) for the reasons detailed below. EPA selected BPJ for the reasons explained in the preamble and this decision is supported by the rulemaking record. BPJ takes into account that some plants may be able to control pollutants at a level greater than BPT. However, the Agency has made changes to the timing and reporting requirements and has further clarified the operation of the BA transport water site-specific purge provisions to address some concerns that commenters raised.

[19] "The regulations address control of the wastewater discharges from deicing operations based on product substitution…" 77 FR 29169

With respect to comments raising benefit-cost reasons for BPJ in connection with bottom ash (BA) purge water, EPA notes that its decisions on the final rule are based on the statutory factors in Sections 301 and 304 of the CWA. As directed by the CWA, the technologies selected in the final rule are "available" and the final rule is "economically achievable" for the industry as a whole. EPA's decisions on the final rule are not based on a benefits analysis, which EPA conducts pursuant to Executive Order. The CWA does not direct EPA to weigh benefits against costs in establishing effluent limitations based on BAT, and multiple judicial decisions have noted that BAT, unlike BPT, is to be established without reference to cost-benefit analysis. *See EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 70-71 (1980) ("[I]n assessing BAT[,] total cost is no longer to be considered in comparison to effluent reduction benefits."); *Ass'n of Pac. Fisheries v. EPA*, 615 F.2d 794, 818 (9th Cir. 1980) ("The conspicuous absence of the comparative language contained in section 304(b)(1)(B) leads us to the conclusion that Congress did not intend the Agency or this court to engage in marginal cost-benefit comparison."); *Am. Iron & Steel v. EPA*, 526 F.2d 1027, 1051-52, 1053 n.54 (3d Cir. 1975) ("there should be no cost-benefit analysis" for BAT); *Nat'l Ass'n of Metal Finishers v. EPA*, 719 F.2d 624, 659 (3d Cir. 1983) ("BPT is designed to eliminate inefficient discharges, *i.e.*, where the benefits of pollutant reduction exceed the costs. . . . BAT assumes that inefficient discharges have been eliminated . . . [and] require[es] the remaining dischargers to eliminate 'efficient' discharges, [including] where the costs outweigh the benefits of pollutant reduction.").

At the same time, cost is a statutory factor that EPA must consider under CWA section 304(b). EPA acknowledges that a BPJ determination does require some amount of permit authority decision-making and discharger and permit authority paperwork. While EPA concluded that this would not diverge meaningfully from the existing burden for purposes of the Paperwork Reduction Act, several commenters expressed concern that EPA had underestimated costs. One commenter submitted an estimate that a single BPJ determination costs $100,000 and one trade association referenced previous estimates in other EPA rules (e.g., 316(b) rule). While the commenter did not provide sufficient information about its $100,000 BPJ estimate for EPA to assess it, the following sensitivity analysis demonstrates that potential BPJ costs for BA purge water would not change the Agency's conclusions that BPJ is appropriate.

EPA estimates that there are 68 plants that might discharge BA purge water. Using a worst-case assumption that a BPJ determination at each of the 68 plants would cost $100,000, a one-time, industry-wide cost of $6.8 million may be expected.[20] Amortizing this cost over the 20-year life of the equipment at the same seven percent discount rate used for the primary analyses in the Supplemental TDD and RIA, EPA estimates that BPJ for BA purge water could result in up to $0.6 million per year in additional compliance costs to industry. Even assuming these worst-case costs are incurred, the rule would still be economically achievable for the industry as a whole.

[20] Although one trade association interprets this as only the costs to the power plant, it is unclear from the submission whether this estimate includes the cost to the permitting authority as well. To the extent that there might be additional costs to the permitting authority beyond what is estimated above, these costs would not impact either the EPA's conclusion that the costs are reasonable or the EPA's conclusion that BPJ would not diverge meaningfully from the existing permitting paperwork burden.

Using the same seven percent discount rate to further discount these costs to the median implementation year of 2023, EPA estimates that BPJ might result in up to $0.5 million per year in additional social costs ($0.4 million using a three percent discount). For the costs of the actual BPJ-selected technologies themselves, EPA appropriately did not speculate on the costs that might result from a permitting authority's BPJ decision as part of the permitting process. Instead, such costs would be considered in that process. *See* 40 C.F.R. §§ 125.3(c)(2), (d)(3).

With respect to comments about increased uncertainty, EPA notes that the BPJ determination will be made in the permitting process and afford the discharger notice and an opportunity to comment on the BPJ determination. EPA understands that some commenters would prefer to have PUC rate recovery approvals made before costs of BPJ-determined technologies are incurred; however, no commenter has suggested that utility commissions would reject rate recovery of a required environmental compliance technology solely because it was required by a permitting authority's BPJ rather than a national ELG.[21] To the extent that plants can rate recover at a later time, EPA does not find that there is any harm in such recovery being approved after BPJ costs have been incurred.[22] EPA also disagrees that companies cannot plan high recycle rate systems prior to a BPJ analysis being completed. Even during the current rulemaking, companies have continued to evaluate, plan, pilot, and install wastewater treatment technologies. For those designing and selecting high recycle rate systems, such systems can be designed and installed without knowing what additional requirements might be imposed through a BPJ-based BAT determination for BA purge water. While EPA understands that companies would prefer to know all technology-based requirements up-front, nothing about the BPJ-based BAT limitations for BA purge water would materially change the design of, for example, a remote mechanical drag system. And, as mentioned above, the permitting process provides notice and an opportunity to comment prior to the requirement being imposed.

With respect to comments about timing, permits may take longer in some cases if the BPJ analysis is particularly complicated. Nevertheless, the possibility of additional time to perform a thorough BPJ analysis in complicated cases does not warrant the EPA setting BAT limits equal to BPT limits in this case. EPA agrees that while a plant may be able to plan for a range of BPJ technologies prior to completion of a BPJ analysis, it would not be prudent to begin construction of these technologies until the BPJ analysis was completed. This is no different than how BPJ is currently implemented at NPDES covered plants, including steam electric power plants. EPA is not aware of plants being given limitations as a result of a BPJ analysis and then denied the time necessary to implement those limits, and EPA declines to assume this would be the case under the final rule. Finally, EPA agrees that some dry technology options might be precluded for some sites, had the "no later than" date of December 31, 2023, been retained for meeting BAT limitations applicable to BA transport water. EPA has extended the latest compliance dates for

[21] Plants in the electric utility industry have received rate recovery for other site-specific cost such as water quality-based effluent limitations.
[22] EPA also notes that plants in deregulated states may not cost recover at all.

BA transport water to December 31, 2025, and no comments or information provided to EPA indicate a later date than this would be appropriate or necessary.

EPA strongly encourages state and tribal permitting authorities to invest the time and resources necessary to establish BPJ limits for BA purge water and issue permits timely to allow facilities to install the necessary equipment within compliance deadlines in the final rule. EPA can provide technical support to permitting authorities evaluating technologies under BPJ and has provided some general principles in the preamble of the proposed rule to guide permitting authorities (*see* Section XIV.A.2 of the preamble).

With respect to inconsistent treatment, EPA agrees that a BPJ-based approach necessarily means that some plants could receive different limitations than others. Nevertheless, as discussed in the preamble section XIV.B.2, BA purge discharges will vary depending on site-specific issues. After evaluating the record, EPA concluded that the appropriate purge at any given plant may differ in both volume and chemical properties from the purge at another plant, and the EPA does not have nationwide, site-specific data to establish differentiated BAT limits on the various types of BA purge water. Thus, while different limitations and BA purge water requirements will occur across the industry, these differences will reflect the variety of operations at plants across the industry and the variety of purges that EPA projects are necessary.

With respect to some commenters' support for zero discharge of BA purge water, EPA considered and rejected technologies that would achieve zero discharge of bottom ash transport water on a nationwide basis (see preamble section VII); however, one change the Agency made from proposal is to allow permitting authorities to determine not just the treatment for BA purge water, but also the appropriate volume of BA purge water not to exceed 10 percent.

EPA disagrees with commenters who assert that BPJ is not practical to implement. Permitting authorities have been required to undertake, and have completed, BPJ determinations for decades under existing regulations. These BPJ determinations have occurred despite the concerns raised by commenters, including changes to the permitting authorities' resources. To the extent that commenters disagree with particular BPJ determinations, those commenters can participate in the public process and comment on draft permits or appeal final permit decisions.

With respect to EPA's findings in 2015 regarding FGD wastewater, EPA disagrees with commenters' suggestion that for BA purge water "there are sufficient data to set uniform, nationally applicable limitations…" as was the case for FGD wastewater in 2015. First, with the exception of a single EPRI/TVA study on one steam electric power plant, EPA has no data on the constituent concentrations that might be present in BA purge water after it has been recycled through a high recycle rate system. Second, this study performed jar tests, which are a rudimentary way to evaluate physical settling and are not considered bench scale pilots. It did not evaluate a pilot-level or full-scale treatment system. Third, EPA does not have sufficient information to indicate that this one plant's BA purge water is representative of the entire industry. Finally, the fact that different plants will have different needs for BA purge water indicates that not all BA purge water will warrant the same treatment. In some cases, purges may be primarily composed of stormwater and discharged infrequently. Such dilute, infrequent purges could warrant a much different treatment than, for example, a continuous purge that is necessary to eliminate chemical imbalances. The final rule takes a common-sense approach of allowing the permitting authority to consider the volume, frequency and nature of the BA purge at a particular plant and impose technology-based limitations based on the site-specific characteristics.

With respect to comments about documentation and process, EPA has updated the reporting and recordkeeping requirements of section 423.19(c) to better assist plants and permitting authorities as they work to implement the BPJ provisions for BA purge water. First, the final rule requires information that will assist permitting authorities in determining the volume of purge. The final rule requires plants to provide the primary active wetted BA system volume, including material assumptions, so that the permitting authority can determine the total system volume against which purge volumes are evaluated. The final rule also requires plants to provide a list of the discharges that a plant estimates will be necessary to purge during the operation of that system, including material assumptions, so that the permitting authority can determine the percentage of the total volume that must be purged at a facility (provided this is less than 10 percent). Second, the final rule requires plants to provide a list of wastewater treatment systems that are, or will be, installed to treat other wastewaters, as well as a narrative discussion of each system, which will assist the permitting authority in determining whether such a system might be able to accept and treat the BA purge water at that plant. Some commenters requested that EPA allow BA transport water to be sent to FGD wastewater treatment systems. Another commenter suggested that, for many plants, the only other wastewater treatment system would be surface impoundments. EPA agrees with both comments and notes that under the final rule, where a plant provides information demonstrating that diverting BA purge water to these treatment systems is feasible, permitting authorities could find these FGD wastewater treatment systems are an appropriate technology basis for BPJ limits. Although some plants may only have surface impoundments, that is unlikely to be the case going forward, as this final rule requires additional treatment technologies for FGD and BA transport water.

Some commenters argued that BPJ-based decisions should not be applied for BA transport water contained in equipment at the end of its useful life. EPA disagrees and the final rule establishes that BAT for BA purge (volume and effluent limitations) is established by the permitting authority based on BPJ. As discussed in responses to Code 21a (Bottom Ash Transport Water – High Recycle Rate – Purge Basis, Provisions, & Regulatory Language), EPA has updated the maintenance water condition for discharging BA transport water to be defined as maintenance not otherwise covered by other provisions. This more inclusive definition captures water remaining in high recycle rate equipment at the end of its useful life. This wastewater, like other BA purge, can be discharged (or drawn down), up to 10% on a rolling 30-day average, subject to the BPJ limitations determined by the permitting authority.23 Thus, these end of life draw down

[23]To the extent that precipitation or other water flows naturally flow into the BA system and mix with BA transport water, such treatment ensures that these waters may continue to be discharged pursuant to the permitting authority-determined purge requirements.

discharges should be included by the permittee in the reporting required under 423.19(d). These provisions apply to the BA purge from high recycle rate systems and do not apply to end of life discharges from plants that opt into the subcategories in the final rule.

EPA agrees with commenters who pointed out that the volumes of BA transport water (and therefore pollutants) remaining in a system after a plant ceases coal combustion would be small.24 Nevertheless, using the small size of pollutant loadings to set BAT limitations equal to BPT limitations has been rejected for other wastestreams in this industrial sector. *See Southwestern Elec. Power Co. v. EPA*, 920 F.3d at 1026 (rejecting EPA's reliance on the relatively small size of combustion residual leachate as a reason to set BAT limitations equal to BPT limitations).

5 Regulatory Options – Compliance Cost Methodology

Leasing

EPA disagrees with the commenter who asserted that cost evaluations "should more appropriately compare technologies based on their cost per gallon of wastewater treated." EPA chose not to rely on cost per gallon estimates to meet its statutory requirement to ensure that the final rule is economically achievable to the industry as a whole because a cost per gallon analysis would not make use of plant-specific factors that can have major impacts on economic achievability. The BAT caselaw establishes that economic achievability is determined based on whether the costs of the pollution reduction technology can be "reasonably borne" by the industry." *See, e.g.*, *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 262 (5th Cir. 1988). As described in Section 5 of the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001) (Supplemental TDD), EPA estimates compliance costs for individual plants based on their FGD wastewater flows. Because individual plants can have varying levels of existing treatment or other characteristics that may impact costs at that specific plant (e.g., onsite or offsite landfills), this approach is a better approximation of costs to the industry as it exists by including relevant plant-specific details. EPA's analysis is a reasonable estimate of the costs that will actually be incurred by the final rule summed across all plants, whereas cost per gallon estimates do not account for plant-specific factors and cannot accurately be readily summed to provide a useful industry-wide estimate of total costs of the rule. As described in the Supplemental TDD, EPA's compliance cost estimates account for both capital costs (including engineering and construction management) and operation and maintenance (O&M) costs, including any costs that may occur on a frequency other than annually. In addition, EPA's analysis does consider the timing at which costs are incurred and the life of the equipment. The compliance cost estimates and the social cost analysis is described in the *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA Report) (EPA-821-R-20-003).

[24] A typical high recycle rate system has a volume of half a million gallons.

One commenter asserted that EPA should have used its build own operate maintain (BOOM) business model to evaluate costs of the rule and that "EPA's technology discussion and economics model overlook the BOOM business model and result in a conclusion that power plants with unknown remaining lives cannot afford wastewater treatment." BOOM is a vendor-specific marketing model. Under this business model industrial plants enter into contract with Purestream for the treatment of wastewater. Purestream owns, operates, and maintains the treatment system and charges clients a fee per gallon of wastewater treated (see *Final Purestream Meeting Notes* (document control number (DCN) SE08590)). Purestream markets thermal treatment technologies, including its AVARA system (a distillation and brine concentration technology) and its FLASH system (an evaporation system).

EPA is aware of other vendors offering leasing opportunities for flue gas desulfurization wastewater (FGD) wastewater treatment and management of bottom ash transport water. One commenter (EPA-HQ-OW-2009-0819-8295, Comment Excerpt 2) stated that that, "Further innovation has resulted in the development of the first mobile bioreactor platform for final rule compliance of FGD blowdown. Our mobile systems are offered as a lease or purchase which provides additional operational and budgetary flexibility to the end-users." United Conveyor Corporation (UCC) offers mobile and/or leased systems for the management of bottom ash transport water (DCN SE08972).

EPA understands from commenters that the use of third-party owned and operated treatment equipment is not uncommon to power plants. Some commenters stated that some companies have made use of temporary equipment that is owned and operated by third parties. For example, situations requiring short-term treatment to meet effluent limitations prior to discharge (e.g., pond dewatering) have seen companies make use of temporary equipment that is owned and operated by a third party (see DCN SE08633). Furthermore, electric utilities have commented that EPA should consider their use of such temporary equipment (EPA-HQ-OW-2009-0819-8458-A1). EPA acknowledges that leasing services for FGD wastewater and bottom ash transport water equipment are available; however, EPA is not aware of any plants that have leased equipment for treatment of FGD or BA transport water. Additionally, commenters did not provide sufficient background information on the components included in its cost estimates or performance data (such as those used by EPA to conduct its cost estimates described in Section 5 of the Supplemental TDD) on the leased treatment that would enable EPA to conduct necessary cost estimate analyses and to evaluate whether or not the system is equivalent to the technology basis evaluated for the final rule.

Thermal Treatment

Some commenters asserted that the steam electric power generating industry has gained experience with thermal treatment and encapsulation for FGD wastewater since the 2015 rule. EPA agrees; however, based on the information in the rulemaking record EPA still estimates that thermal technology will cost 1.04 times more than CP+LRTR. (see the *Flue Gas Desulfurization Thermal Evaporation Cost Methodology* memorandum (DCN SE08631)). The cost values provided by the commenter for their thermal systems do not include specific details on cost components included or not included and, therefore, could not be incorporated in the EPA's analyses for the final rule. As stated in the preamble, EPA is not establishing BAT limitations for FGD wastewater under the final rule based on evaporation or other thermal treatment technology. See Section VII.B.1 of the preamble for rationale for the final BAT for FGD wastewater.

One commenter asserted that "EPA analyses has misplaced confidence in technology advancements and price reductions for advanced membrane and paste technologies and failed to consider current and future technology advancements for thermal technologies, so the BAT analyses are biased against thermal processes." While EPA acknowledges that thermal treatment technologies are used to treat FGD wastewater, both at full-scale and pilot-scale (see Section 4 of the *Supplemental Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental TDD) (EPA-821-R-20-001), the commenter has not provided data to support their claim that EPA's analyses are biased. EPA's rationale for its selection of BAT for the final rule is described in section VII.B.1 of the preamble.

The commenter also discussed its brine management techniques; however, the cost values provided by the commenter for these alternative brine mixtures do not include specific details on cost components included or not included and, therefore, could not be incorporated in the EPA's analyses for the final rule. Additionally, it is unclear from the commenter's description how the solidification of brine resulting from thermal treatment or membrane filtration systems by the encapsulation technology evaluated by EPA differs from the "high Cement mix" and "grout" mentioned by the commenter. EPA's cost methodology for membrane filtration includes costs for disposal of brine using encapsulation and EPA's cost estimate for thermal treatment includes crystallization to a solid salt that can be disposed of in a landfill. The cost savings cited by commenters for using solidified brine as "crushed fill" or "flowable fill" to beneficially reuse material for impoundments, landfills, or other construction projects is not included in EPA's nationwide cost methodology as these reuse alternatives are site-specific, and EPA lacks data on which plants may be able to reuse this material. EPA estimated costs for all plants to landfill the solidified material. The final rule does not preclude the use of any specific technology(ies) (*e.g.,* encapsulation with grout mixes) or require that specific technology(ies) must be used. EPA's final rule establishes specific technology-based effluent limitations and standards that apply to certain wastestreams. Therefore, as long as they meet the final BAT limitations, plants may choose to encapsulate brine into grout mixtures. See response to comment code 17 for additional discussion on management of brine from membrane filtration systems.

One commenter asserted that EPA should consider the cost-effectiveness on a unit-by-unit basis. EPA disagrees. EPA is required to evaluate BAT based on technological availability and economic achievability for the industry as a whole, in light of the statutory factors listed in CWA section 304(b). While unit-by-unit costs are estimated by EPA, they are only part of the analysis that EPA conducts to support its determination of BAT. See Section VII of the preamble for rationale for BAT for the final rule. Importantly, the cost estimates prepared by EPA for the final rule are not designed to reflect changes to an industry with exact precision. *See BP Exploration*

& Oil, Inc. v. EPA¸66 F.3d 784, 800 (6th Cir. 1995) ("'The CWA does not require a precise calculation of BAT and NSPS costs.'") (quoting *NRDC, Inc. v. EPA,* 863 F.2d 1420, 1426 (9th Cir. 1988)); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 237-38 (5th Cir. 1989) ("The Act requires the EPA to 'take into account' the costs of BAT; it does not require a precise calculation. The EPA 'need make only a reasonable cost estimate in setting BAT'; it is sufficient if the EPA develops 'a rough idea of the costs the industry would incur.'") (internal quotations and citations omitted); *see also Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 936 (5th Cir. 1998) (EPA's effluent reduction estimates were performed "only to satisfy the CWA's unrelated requirement that the EPA 'identify' in its regulations the degree of effluent reduction attainable through the application of BAT . . . As such, even serious flaws in the effluent reduction estimates could not provide grounds for remanding the zero discharge limit.") (citing 33 U.S.C. § 1314(b)(2)(A)).

The commenter also suggested that EPA should "avoid requirements that impose additional burden on these lesser utilized units." The final rule includes a subcategory for units with low cumulative use rates (low utilization). See section VII.C.2 of the preamble for details on this subcategory.

One commenter asserted that the estimated cost to industry to comply with the rule does not take into account the costs to restore polluted rivers and streams that would result from the changes, a potential benefit category. This is correct. EPA's cost estimate analysis is consistent with the CWA and E.O. 12866, and is intended to reflect costs borne by the industry as a whole. While EPA did not make decisions in this final rule based on its benefits analysis, EPA did evaluate all benefit categories to the extent feasible, as described in the BCA.

Cost-Effectiveness

Some commenters focused on the ratios of costs and pollutant removals (i.e., cost-effectiveness) in their support of a specific regulatory option. EPA notes that cost-effectiveness is not a statutory factor in establishing ELGs. EPA explained the bases for the final rule in the preamble. In particular, EPA's decisions followed the requirements in sections 301(b) and 304(b) of the Clean Water Act specifying that Best Available Technology Economically Achievable ("BAT") represents effluent limitations that are technologically available and economically achievable after a consideration of the following factors: the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impacts (including energy requirements), and such other factors the Administrator deems appropriate.

One commenter stated that EPA should base the final rule only on technologies that are cost-effective in terms of how much the technology costs in dollars per toxic-weighted pound equivalent (TWPE) removed, and in particular technologies that cost less than $100/TWPE. EPA interprets this statement about cost-effectiveness to refer to the kind of cost-effectiveness analysis that EPA traditionally performs for ELGs. In its effluent guidelines rulemakings, EPA uses the term "cost effectiveness" as a measure of the cost[25] per pound of pollutant discharge reduction (for BAT, these pollutant discharge reductions are normalized to account for the different toxicity among pollutants[26]). EPA understands that this commenter uses the term cost-effectiveness to mean a measure of cost per pound of toxic-weighted pound of pollutant discharge reduction. While EPA often calculates and presents cost-effectiveness values when conducting ELG rulemakings, it generally does not use cost-effectiveness as a decision criterion in establishing BAT. The Agency did not use the results of its "cost-effectiveness" analysis as the basis for its decisions on the 2015 steam electric ELG rule or for these revisions to the steam electric ELGs.

EPA's decision not to use the results of its cost-effectiveness analysis to establish BAT for the final steam electric ELGs is consistent with the statutory text, structure, and history of the Clean Water Act, and it achieves the goals of the Act. The Act does not direct BAT to reflect a consideration of a weighing of costs in relation to pounds of pollutant discharge reductions, but rather requires BAT to reflect what is technologically and economically achievable after a consideration of, among other things, "the cost of achieving such effluent reduction." Thus, for BAT, instead of comparing costs to pounds of pollutant discharge reductions, EPA typically estimates the costs of compliance and determines whether they are affordable to the industry as a whole, or whether the costs can be "reasonably borne" by the industry.[27] EPA has generally looked at the affordability of the costs on the industry as a whole (or for a subcategory of the industry, as appropriate) by analyzing the effect of the regulation on plant closures and, to a more limited degree, firm failures.[28] In a few past instances, EPA has also considered total industry costs, rather than impacts on plant closures or firms, in establishing BAT.[29] Once EPA has identified technologically available and economically achievable options, some courts have stated that the Agency is allowed to consider whether increasingly more stringent requirements

[25] Costs are the estimated annualized incremental pre-tax costs to comply with alternative regulatory options, which, following conventions, are stated in 1981 constant dollars. The annual costs include the annualized capital outlays for equipment and recurring expenses for operating and maintaining compliance equipment and meeting monitoring requirements.

[26] EPA adjusts the estimated reductions in discharges, or pollutant discharge reductions, associated with a regulatory option by multiplying the estimated reduction quantity for each pollutant by a normalizing toxic weight (toxic-weighting factor, or "TWF"). The use of TWFs allows the reductions of different pollutants to be expressed on a constant toxicity basis. In the case of indirect dischargers, the reduction also accounts for the effectiveness of treatment at Publicly Operated Treatment Works ("POTWs").

[27] *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 262 (5th Cir. 1989); *BP Exploration & Oil, Inc. v. EPA,* 66 F.3d 784, 799-800 (6th Cir.1996). *See also Nat'l Wildlife Fed'n v. EPA*, 286 F.3d 554, 570 (D.C. Cir. 2002); *CPC Int'l Inc. v. Train*, 540 F.2d 1329, 1341-42 (8th Cir. 1976), *cert. denied,* 430 U.S. 966 (1977).

[28] *See Nat'l Wildlife Fed'n*, 286 F.3d at 562-65; *Nat'l Ass'n of Metal Finishers v. EPA*, 719 F.2d 660, 666 (3d Cir. 1983); *Am. Iron & Steel v. EPA*, 526 F.2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pac. Fisheries v. EPA*, 615 F.2d 794, 808 (9th Cir. 1980)..

[29] *See* 48 Fed. Reg. 32462, 32468 (July 15, 1983) (Final Rule establishing ELGs for the Electroplating and Metal Finishing Point Source Categories); 74 Fed. Reg. 62996, 63026 (Dec. 1, 2009) (Final Rule establishing ELGs for the Construction and Development Point Source Category); *BP Exploration & Oil, Inc.,* 66 F.3d at 796-97.

would impose significant costs while achieving only *de minimis* incremental pollutant reductions.[30,31]

Moreover, the Act's structure and history clearly contemplate a two-step, phased-in approach to technology-based effluent limitations, where the first step represents what is "practicable," and the second step is directed toward the complete elimination of discharges if such elimination is "technologically and economically achievable." Thus, EPA views cost-effectiveness as more closely relevant to establishing the first step of technology-based limitations, BPT. Indeed, unlike section 304(b)(2)(B), section 304(b)(1)(B) of the Act expressly directs that BPT reflect a consideration of "the total cost of application of technology in relation to the effluent reduction benefits to be achieved from such application." Interpreting that provision, EPA has traditionally considered cost per pound of pollutant discharge reduction when establishing BPT. Due to the difference in the language used in section 304(b)(1)(B) compared to the language used in section 304(b)(2)(B), EPA does not view as determinative cost per pound (or toxic-weighted pound) of pollutant discharge reduction for establishing controls reflecting BAT.32 This is also consistent with numerous other judicial interpretations.33 EPA's view is that its specific goal in section 301

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30 *Ass'n of Pac. Fisheries*, 615 F.2d at 818 ("So long as the required technology reduces the discharge of pollutants, our inquiry will be limited to whether the Agency considered the cost of the technology, along with the other statutory factors, and whether its conclusion is reasonable. Of course, at some point extremely costly more refined treatment will have a *de minimis* effect on the receiving waters."); *Am. Petroleum Inst. v. EPA*, 787 F.2d 965, 972 (5th Cir. 1986) ("EPA would disserve its mandate were it to tilt at windmills by imposing BAT limitations which removed *de minimis* amounts of pollutant agents from our nation's waters, while imposing possibly disabling costs upon the regulated industry."); *Am. Petroleum Inst. v. EPA*, 858 F.2d 261, 265-66 (5th Cir. 1988), *amended by* 864 F.2d 1156, 1156-57 (5th Cir. 1989) ("BAT limitations properly may require industry, regardless of a discharge's effect on water quality, to employ defined levels of technology to meet effluent limitations; a direct cost/benefit correlation is not required, so even minimal environmental impact can be regulated, so long as the prescribed alternative is 'technologically and economically achievable.' We are mindful, however, that this approach has its limits, as explained by Judge (now Justice) Kennedy in *Ass'n of Pac. Fisheries*.") (citations omitted).

31 EPA also considers non-water quality environmental impacts and has on previous occasion based a decision not to select a technology option due to such impacts. *See* Effluent Limitations Guidelines, Pretreatment Standards, and New Source Performance Standards for the Commercial Hazardous Waste Combustor Subcategory of the Waste Combustors Point Source Category; Final Rule, 65 Fed. Reg. 4360, 4368 (Jan. 27, 2000); *BP Exploration & Oil, Inc.*, 66 F.3d at 796-97.

32 *See Keene Corp. v. United States*, 508 U.S. 200, 208 (1993) ("Where Congress includes particular language in one section of a statute but omits it in another . . . , it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (citation and internal quotations omitted); *See also Dep't of Homeland Security v. MacLean*, 135 S. Ct. 913, 919 (2015) ("Congress generally acts intentionally when it uses particular language in one section of a statute but omits it in another.") (citation omitted). The same can be said in contrasting section 304(b)(2)(B)'s silence regarding costs versus benefits with the BCT provision, section 304(b)(4)(B), which directs EPA to consider "the reasonableness of the relationship between the costs . . . and the effluent reduction benefits derived."

33 *See EPA v. Nat'l Crushed Stone Ass'n*, 449 U.S. 64, 70-71 (1980) ("[I]n assessing BAT[,] total cost is no longer to be considered in comparison to effluent reduction benefits."); *Ass'n of Pac. Fisheries*, 615 F.2d at 818 ("The conspicuous absence of the comparative language contained in section 304(b)(1)(B) leads us to the conclusion that Congress did not intend the Agency or this court to engage in marginal cost-benefit comparison."); *Am. Iron & Steel v. EPA*, 526 F.2d at 1051-52, 1053 n.54 ("there should be no cost-benefit analysis" for BAT); *CPC Int'l, Inc. v. Train*, 540 F.3d 1329, 1341-42 (8th Cir. 1976), *cert. denied*, 430 U.S. 966 (1977) (BAT is "governed by standard of reasonableness without the necessity of a thorough cost-benefit analysis.") (citations omitted); *Reynolds Metals Co. v. EPA*, 760 F.2d 549, 565 (4th Cir. 1985) ("For BPT there must be a 'limited balancing' of costs against benefits, but as regards BAT, NSPS, PSES and PSNS no balancing is required . . . .") (citations omitted); *Rybachek v. EPA*,

that BAT result in the elimination of discharges where technologically and economically achievable,34 is achieved if EPA does not base BAT on a weighing of costs against pounds of pollutant discharge reductions, but rather focuses most importantly on the Act's requirement that BAT limitations reflect what is technologically available and economically achievable for the industry as a whole (while taking into account the express factors in section 304(b)).

EPA's approach for the final steam electric ELGs is consistent with its obligations under the Act. EPA analyzed the effect of the final rule on steam electric generating unit and plant closures and determined that the rule is affordable to the industry as a whole (see preamble Section VII.F). EPA also considered the total industry costs and concluded it would not be appropriate to establish BAT limitations based on certain regulatory options due in part to total industry cost (see Section VII of preamble). The final steam electric ELGs do not impose very high costs in exchange for only *de minimis* pollutant reductions. Finally, EPA concluded that the final rule contains acceptable non-water quality impacts (see preamble Sections VII.G and X).

In addition to the fact that EPA's decision not to use as determinative the results of its cost-effectiveness analysis in establishing BAT is consistent with and implements the Act, EPA notes several limitations with its cost-effectiveness analysis that make the Agency cautious of its value as a decision tool. First, the toxic-weighting factors ("TWFs") used to calculate toxic-weighted pollutant discharge reductions are derived from chronic aquatic life criteria and human health criteria (or toxic effect levels). The TWF only uses the fish consumption component of the human health criteria, where available. In cases where only one of these two criteria is available, TWFs account for only one particular type of harm. In this sense, they could be incomplete.

Second, this analysis does not account for all pollutants. Not all pollutants have TWFs, either because data are not available to set a TWF or toxicity is not the pollutants' primary environmental impact (e.g., ecological impacts of selenium).

In addition, the TWF measurement is not a measure of impacts on the environment or human health because it does not account for the fate or potential risk of a pollutant. Risk is a function

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904 F.2d 1276, 1290-91 (10th Cir. 1990) ("In determining the economic achievability of a technology, the EPA must consider the 'cost' of meeting BAT limitations, but need not compare such cost with the benefits of effluent reduction.") (citations omitted); *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 936 (5th Cir. 1998) ("In applying the BAT standard, the EPA is not obligated to evaluate the reasonableness of the relationship between costs and benefits. . . . Indeed, the EPA may prescribe ELGs whose costs are significantly disproportionate to their benefits, just as long as the BAT determination remains economically feasible for the industry as a whole.") (citations omitted); *Am. Paper Inst. v. Train*, 543 F.2d 328, 338, 354 (D.C. Cir. 1976) ("Section 304(b)(2)(B) mandates no such [cost-benefit] balancing for the 1983 [BAT] limitations, nor does Section 306 require it for the new source performance standards."); *Nat'l Ass'n of Metal Finishers v. EPA*, 719 F.2d 624, 659 (3d Cir. 1983) ("BPT is designed to eliminate inefficient discharges, i.e., where the benefits of pollutant reduction exceed the costs. . . . BAT assumes that inefficient discharges have been eliminated . . . [and] requir[es] the remaining dischargers to eliminate 'efficient' discharges, [including] where the costs outweigh the benefits of pollutant reduction."); *Southwestern Elec. Power Co. v. EPA*, 920 F.3d at 1006 ('Unlike BPT, however, the BAT factors omit a cost/benefit analysis and replace it with a requirement to consider only "the cost of achieving such effluent reduction."') (quoting *Tex. Oil & Gas*, 161 F.3d at 928 and citing *Nat'l Crushed Stone*, 449 U.S. at 71).

[34] *Id*. § 1311.

of toxicity and exposure. Only detailed exposure assessment data, based on an analysis of the fate and transport of pollutant discharge, exposure pathways, and uptake, would provide the information necessary to evaluate the extent to which regulatory options reduce environmental impacts and enhance human and ecological health. Site-specific conditions in the receiving waterbody, such as hydrodynamics and exposed fauna and biota, can result in different environmental effects beyond those that may be suggested by comparing pollutant mass only, even when adjusted for toxicity.

Lastly, cost per pound or toxic-weighted pound of pollutant discharge reductions is not a measure of economic achievability and can be in tension with economic achievability, which is the standard EPA is required to consider in establishing ELGs. A technology may be economically achievable because it is affordable to the industry as a whole, yet have a higher cost per pound or toxic-weighted pound of pollutant discharge reduction value than another technology. Conversely, the aggregate costs of a regulatory option and its associated burden on industry and the economy can cause a regulatory option to not be economically achievable, regardless of its cost per pound or toxic-weighted pound of pollutant discharge reduction. For these reasons, cost effectiveness is not determinative for establishing BAT. Thus, to the extent that commenters on the proposed ELGs raised issues challenging EPA's data or methodology for estimating the "cost-effectiveness" of the rule, even assuming that EPA were to recalculate the cost-effectiveness values and get different results, these different results would not affect EPA's decisions on the final rule.

6 Regulatory Options – Pollutant Loadings Methodology

No comment excerpts were received on this topic.

7 Industry Profile and Plant Operations

As described in Section 3 of the Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental TDD) (EPA-821-R-20-001), EPA updated the industry profile post proposal for the final rule to account for current plant operations and plans for future changes in operation announced and verified by February 2020, including information submitted in public comments. EPA's specific methodology for updating the industry profile is described in the Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule memorandum (document control number (DCN) SE08688).[35]

[35] After February 2020, EPA collected information on additional changes in operation. The Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule memorandum (DCN SE08688) describes EPA's sensitivity analysis to determine the impact these additional changes in operation might have on the compliance cost and pollutant loading estimates.

In public comments received on the proposed rule, industry provided information on retirements and fuel conversions. EPA's analyses for the final rule reflect the following plant-specific retirements and fuel conversions specified in public comments:

Table 1. Retirements and fuel conversions added based on public comments

Plant Name (EPA ICR ID)	Applicable Generating Unit(s) [a]	Change in Operation	Effective Year
Brunner Island (4122)	SE Unit-1; SE Unit-2; SE Unit-3	Fuel Conversion	2028
C D McIntosh Jr. (3200)	SE Unit-3	Retirement	2024
DE Karn (2612)	SE Unit-1; SE Unit-2	Retirement	2023
JH Campbell (5839)	SE Unit-1; SE Unit-2	Retirement	2031
JH Campbell (5839)	SE Unit-3	Retirement	2040
Paradise (16)	SE Unit-3	Retirement	2020
Winyah Generating Station (7411)	SE Unit-1; SE Unit-2	Retirement	2027
Winyah Generating Station (7411)	SE Unit-3; SE Unit-4	Retirement	2023

a – Generating units reflect those defined in the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (DCN SE05924).

As part of public comments, EEI and Xcel Energy provided general information on the number of electric generating units power companies are expected to retire or repower; however, these commenters did not provide sufficient plant-specific information for EPA to fully assess and incorporate into its analyses. EPA agrees with EEI that "[b]ecause some plant closure details and/or plans for replacement generation have not been finalized, it is not possible to determine the exact number of closures, the mix and quantity of generation replacing the retiring coal units, or the exact amount of emissions reductions." Nonetheless, EPA's analyses may account for these changes in operation if information was collected from other publicly available data sources. See the Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule memorandum (DCN SE08688) for a comprehensive list of all changes in operation accounted for since the 2015 rule.

Talen Energy stated that the company is "considering the option of repowering its Montour plant located near Washingtonville, PA" and "has yet to make its final decision because of market and regulatory uncertainties." Lacking definitive information, EPA did not account for possible fuel conversion, and it estimated compliance costs and pollutant loadings for the Montour plant.

UWAG provided information on the management and treatment of FGD wastewater at the co-located Oak Creek Power Plant and Elm Road Generating Station. EPA is aware that FGD wastewater from both plants is treated using an existing chemical precipitation system at Elm Road Generating Station.36 EPA disagrees that it did not account for the FGD wastewater flows or corresponding compliance costs for Oak Creek Power Plant to comply with the FGD wastewater requirements. EPA estimated zero compliance costs and zero pollutant loadings for Oak Creek Power Plant, but estimated compliance costs and pollutant loadings for Elm Road

[36] As described in the Flue Gas Desulfurization Wastewater Treatment in Place at Steam Electric Power Plants memorandum (DCN SE08629), EPA's analyses account for current FGD wastewater treatment using chemical precipitation for Elm Road Generating Station.

Generating Station using the total combined FGD wastewater flow, 300,000 gallons per day, for both plants through the existing chemical precipitation treatment system. See the Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings memorandum (DCN SE08630). This flow accounts for FGD wastewater contributions from both Oak Creek Power Plant and Elm Road Generating Station as identified in NDPES Permit WI0000914-08-0 (DCN SE06859A03 and SE06859A04).

In public comments received on the proposed rule, industry provided information on current FGD wastewater treatment and bottom ash handling operations. As described in the Flue Gas Desulfurization Wastewater Treatment in Place at Steam Electric Power Plants memorandum (DCN SE08629), EPA's analyses for the final rule reflects the operation of a chemical precipitation treatment system at Dallman, a chemical precipitation treatment system at Elm Road Generating Station, and a thermal treatment system at GSP Merrimack Station. UWAG also provided information on bottom ash operations for seven power plants. EPA updated the analyses for the final rule, including compliance cost and pollutant loading estimates, for these plants based on this information. Specifically, EPA's analyses for the final rule reflect the following:

- W.H. Sammis, W.A. Parish, Keystone, Brunner Island, and Montour currently operate a wet bottom ash system with no recycle.
    - EPA estimated compliance costs and pollutant loadings for Keystone based on the installation of a high recycle rate bottom ash system to comply with the bottom ash transport water requirements established by the final rule.
    - EPA assumed W.A. Parish and Montour will install high recycle rate bottom ash systems to replace unlined and clay-lined coal combustion residuals (CCR) surface impoundments impacted by the CCR rule as it did with other plants where the CCR rule is expected to close all impoundments at the plant. EPA estimated compliance costs and pollutant loadings for these plants based on this assumption, that the plants would already be operating a high recycle rate bottom ash system to meet the requirements at the time the final rule becomes effective.37
    - All coal-fired electric generating units at Brunner Island are expected to retire or convert to non-coal fuel sources by December 31, 2028. EPA estimated compliance costs and pollutant loadings for this plant based on it being in the subcategory for units permanently ceasing coal combustion by 2028 subcategory established by the final rule.
    - All coal-fired electric generating units at W.H. Sammis are expected to retire or convert to non-coal fuel sources by December 31, 2023. EPA did not estimate compliance costs or pollutant loadings for this plant.

[37] EPA estimated zero compliance costs for these plants to comply with the bottom ash requirements for the final rule. EPA estimated baseline compliance costs for these plants to install RO systems to meet the no discharge requirements of the 2015 rule. See Supplemental TDD Section 5.3.1.

- UWAG stated in its comments that "H.A. Wagner (Unit 3) has a partial bottom ash (BA) transport water recycle treatment system that would possibly need upgrades to meet the proposed BA transport water requirements. But EPA assumed this unit would not incur any costs." EPA did not estimate costs for H.A. Wagner as part of the 2013 proposed rule and neither UWAG nor the plant submitted comments following the 2013 proposal to state that was incorrect. UWAG did not identify any specific upgrades that the plant would need to meet the BA transport water requirements in its comment on the 2019 proposed rule. However, as a result of UWAG's most recent comment, EPA included a one-time cost associated with consulting an engineer to eliminate the need and the capacity to discharge bottom ash transport water (i.e., bottom ash management costs), apart from the purge allowed under the final rule, to meet the requirements of this final rule.
- UWAG did not specify what recirculation equipment would be needed or installed or identify associated costs for Kingston and Shawnee to recycle the bottom ash transport water from the existing system back to the electric generating unit for reuse. EPA did estimate capital and O&M costs for these plants to install pumps and piping for recirculation of bottom ash transport water for the final rule. See the Methodology for Estimating Bottom Ash Transport Water Compliance Costs for the Final Revisions to the Steam Electric ELGs memorandum (DCN SE08505).
- In their public comment letter, TVA states the Bull Run, Kingston, Cumberland, Shawnee, and Gallatin plants all have or will have systems compliant with the CCR rule (either composite-lined CCR surface impoundments or tank-based system). EPA's analyses for the final rule reflect no predicted changes in operation for Bull Run, Kingston, Cumberland, Shawnee, and Gallatin to comply with Part A of the CCR rule (i.e., EPA did not adjust the compliance costs or pollutant loadings estimates for these plants based on the CCR rule analysis). See the response to Code 8 (Adjustment for CCR, CPP, and ACE rules) for details on how EPA adjusted the analyses for the final rule, including incorporating CCR compliance costs into the baseline, to account for impacts of the CCR rule.

8 Adjustment for the Coal Combustion Residuals (CCR)/Clean Power Plan (CPP)/Affordable Clean Energy (ACE) Rules

EPA's analyses for the final rule account for the potential cumulative impact that multiple environmental regulations might have on the electric power industry and are consistent with EPA's requirements under the Clean Water Act (CWA) and applicable Executive Orders, including Executive Orders 12866 and 13563.

As discussed in Section 1.3 of the Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental TDD) (EPA-821-R-20-001), EPA finalized the Part A Coal Combustion Residuals (CCR Part A) rule in July 2020. Based on CCR Part A, plants with unlined or clay-lined CCR surface impoundments are required to change operations, retrofit, or install a new CCR-compliant impoundment. As explained in the preamble, the EPA Office of Water coordinated the Effluent Limitations Guidelines and Standards (ELGs) analyses with EPA Office of Resource Conservation and Recovery (ORCR) to identify changes potentially affecting the universe of plants to which this final rule apply. EPA analyzed the final rule as well as other ELG regulatory options under scenarios that accounted for the predicted change in plant operations regarding the handling of CCRs under CCR Part A.[38]

Some commenters stated that EPA incorrectly assumed "that costs imposed by virtue of CCR rule requirements that prohibit the use of existing waste treatment facilities are costs of the CCR rule, rather than costs of the ELG rule." While EPA agrees that the CCR rule does not establish treatment requirements for wastewater that can no longer be treated in unlined and clay-lined surface impoundments, the Agency disagrees with commenters who asserted that changes in operation prompted by the CCR rule should be considered ELG costs and that the Agency underestimated impacts of the 2015 rule. As described in Section 3.3 of the Supplemental TDD and in the preamble for CCR Part A, EPA's compliance costs estimates for the CCR rule include all aspects of CCR management, including conversion to dry handling; and, for some affected plants, to close CCR disposal surface impoundments. The dry handling conversion costs developed for the CCR rule are based on average capital and O&M cost data for wet-to-dry conversions (e.g., tank-based and mechanical drag chain systems) collected from the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (document control number (DCN) SE05924) conducted for the ELGs and 2012 U.S Energy Information Administration data for the volume of CCR disposed in onsite surface impoundments – see *EPA's 2015 RCRA Final Rule Regulating CCR Landfills and Surface Impoundments At Coal-Fired Electric Utility Power Plants* (EPA-HQ-RCRA-2009-0640-12034). Therefore, the CCR rule already accounts for costs for affected plants to convert to dry handling systems which can meet the best available technology economically achievable (BAT) standard established in the final rule.[39]

For the final rule, EPA used industry-reported CCR surface impoundment liner designation data to identify plants operating unlined and clay-lined surface impoundments that are required to close or retrofit their impoundments. As described in Section 3.3 of the Supplemental TDD, EPA assumed that plants where all active CCR surface impoundments are unlined or clay-lined will install tank-based flue gas desulfurization (FGD) wastewater treatment or tank-based bottom ash handling to meet the requirements of the CCR rule.40

[38] For a discussion of the potential impacts of the proposed Part B amendments to the CCR rule, see Assessment to the economic impacts of the final revised Steam Electric ELGs relative to an alternative baseline including the CCR Part B Rule (DCN SE09360).

[39] While nothing in the CCR rule prohibits a facility from constructing a new composite-lined surface impoundment or retrofitting an existing impoundment, the Regulatory Impact Analysis (RIA) for the 2015 CCR rule estimated that conversion to dry handling was a less costly alternative than construction and operation of a new composite-lined surface impoundment, which is consistent with statements made by electric utilities in discussions with EPA. See Final Seminole Site Visit Notes (DCN SE03770).

[40] For FGD wastewater, this tank-based treatment is assumed to be equivalent to the chemical precipitation system described in Supplemental TDD Section 5.2.2. For bottom ash, this tank-based handling is assumed to be one of two systems: either a dry bottom ash handling system, consistent with the MDS system, or a high recycle rate bottom ash handling system, consistent with the rMDS system (described in Supplemental TDD Section 5.3).

EPA agrees with one commenter who said that some plants use "CCR-compliant surface impoundments to manage [bottom ash transport water] at some of their facilities." For plants with at least one CCR surface impoundment not impacted by the CCR rule (e.g., plants already operating CCR-compliant surface impoundments), EPA assumed that the plant will continue to operate their CCR-compliant impoundment(s) and that the CCR rule requirements will not lead to any changes in the plant's existing FGD wastewater treatment or bottom ash handling systems. EPA assumed that these plants will incur compliance costs to meet ELG requirements and calculated compliance costs and pollutant loading estimates for these plants.

EPA identified 27 plants in its analyses that were not present in the CCR impoundment dataset. EPA assumed that these 27 plants would incur the full costs of conversion under the final rule. Since these plants do not report any surface impoundments on their CCR compliance website, it is possible that these impoundments have closed and the plants have already converted to tank-based handling. In those cases, the final costs of this rule may be overestimated.

EPA's analyses for the final rule account for plant-specific CCR rule compliance information where it was provided in public comments (e.g., Bull Run, Kingston, Cumberland, Shawnee, Gallatin, and D.E. Karn). Not all commenters provided plant-specific information for the Agency to consider in its assessment of CCR rule impacts.

EPA understands that some plants subject to the final rule may utilize dewatering bins, concrete settling basins, polishing lagoons, or other alternative technologies to meet the requirements of the CCR rule. For plants that discharge bottom ash transport water and do not operate only unlined or clay-lined CCR surface impoundments, which includes plants operating bottom ash transport water treatments systems that do not meet the requirements of the final rule, EPA assumed costs for a full conversion to a high recycle rate bottom ash system. EPA notes that to comply with the final rule, plants may use any technology or process capable of meeting the technology-based effluent limits.

Based on all of the information EPA evaluated for the final rule, including public comments, EPA concludes that the assumptions made for the final rule about the impacts of the CCR rule on the ELG compliance costs are reasonable even though there are different objectives in the two statutes governing the two rules, and different timeframes. EPA notes that, under the CWA, the Agency is not required to make a precise calculation of estimated costs to comply with the final rule. *See, e.g.*, *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 237-38 (5th Cir. 1989); *Kennecott Copper Corp. v. EPA*, 612 F.2d 1232, 1238 (10th Cir. 1979); *BASF Wyandotte Corp. v. Costle*, 598 F.2d 637, 662 (1st Cir. 1979); *BP Exploration & Oil, Inc. v. EPA*, 66 F.3d 784, 799-800 (6th Cir. 1995); *Natural Resources Defense Counsel v. EPA*, 863 F.2d 1420, 1426 (9th Cir. 1988); *Weyerhaeuser v. Costle*, 590 F.2d 1011, 1045 (D.C. Cir. 1978).

See the response to Code 38 (Coordination with Other EPA Rules) for additional information on the coordination between this final rule and other EPA regulations. See Section VII of the preamble for discussion of the implementation dates of the BAT requirements for bottom ash transport water. See the preamble for additional information on the subcategories for units permanently ceasing coal combustion.

9 Subcategorization

General support for proposed subcategorization

Many commenters provided general support for EPA's use of subcategories in the proposed rule. EPA agrees that EPA has authority to establish subcategories and the subcategories in the final rule are supported in the rulemaking record. As described in section VII.C of the preamble, the final rule includes subcategories applicable to FGD wastewater and bottom ash (BA) transport water for electric generating units (EGUs) with low utilization boilers with a capacity utilization rating (CUR) of less than 10 percent, , and EGUs permanently ceasing the combustion of coal by 2028. In addition, the final rule includes a subcategory applicable to FGD wastewater for units with high FGD flows.

For more information on EPA's rationale for finalizing these additional subcategories, see the following sections in the preamble:

- Plants with High FGD Flows (section VII.C.1)
- Low Utilization EGUs (section VII.C.2)
- EGUs Permanently Ceasing Coal Combustion by 2028 (section VII.C.3)

EPA's response to comments on these individual subcategories can be found in comment codes 9.a (Subcategorization - Retirements & Fuel Conversion by 2028), 9.b (Subcategorization - Low Utilization), and 9.c (Subcategorization - High FGD Wastewater Flow).

Opposition to proposed subcategorization

EPA disagrees with the commenters who asserted that EPA created industry subcategories based solely on their disproportionate compliance costs and contrary to the CWA. The subcategories established in the final rule are based on EPA's consideration of a number of different factors listed at section 304(b)(2)(b), 33 U.S.C. § 1314(b)(2)(B)). EPA has the authority to divide a point source category into groupings called "subcategories" to account for variability between point sources within a category. *See Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 939-40 (5th Cir.1998) (upholding a subcategory for Cook Inlet separately from other areas in the coastal subcategory because Cook Inlet is geographically isolated from other areas in the coastal subcategory and because zero discharge of produced water would result in a disproportionately adverse economic impact in Cook Inlet in terms of closures, job losses, and loss in net present value of the facilities; also upholding subcategory for drilling wastes, where EPA rejected zero discharge due to unique characteristics in Cook Inlet making zero discharge not technically achievable).[41] For BAT, in establishing best available technology economically achievable, the CWA specifies factors EPA is required to consider: the age of equipment and power plants involved, the processes employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reductions, non-water quality environmental impacts (including energy requirements), and such other factors the Administrator deems appropriate. As outlined in section VII.C of the preamble, EPA is creating these subcategories based on the statutory factors of cost, non-water quality environmental impacts (including energy requirements), age of equipment, and other factors the Administrator deems appropriate.

With respect to establishing a subcategory based on costs, EPA is required to consider "cost" under the statute, and that includes consideration of costs for a subcategory. See *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 239 (5th Cir. 1989). EPA has broad discretion in deciding how to account for the consideration factors and the weight to be accorded to each factor. *See Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1045 (D.C. Cir. 1978); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 214; *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998). Using these factors, EPA has broad discretion to subcategorize industries in setting effluent limitations guidelines, particularly where a portion of the industry significantly varies with respect to one of the factors considered in setting the limitations or standards. The standard of review of EPA's decisions to subcategorize is the reasonableness for the discretionary determination. *See, e.g., Chem. Mfrs. Ass'n v. NRDC*, 470 U.S. 116, 133 n.24 (1985) (stating that, when establishing ELGs, often the data indicate differences among segments of the industry, and EPA establishes subcategories to reflect those differences in the effluent limitations and standards that are promulgated). *See also Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1028, 1056 (D.C. Cir. 1978) (In a BPT rule, the court said, "Process is only one of several factors relevant to subcategorization. Other factors may be influential or decisive.").

EPA disagrees with commenters who asserted that the Agency's record does not support finalizing these three subcategories. EPA's rationale and data supporting subcategorization is thoroughly documented in section VII.C of the preamble, including its cost analysis. In addition, EPA's *Steam Electric Effluent Guidelines Reconsideration – Evaluation of Final Rule Subcategories* provides further details on EPA's review of the current market, grid reliability, and evaluation of the Energy Information Administration/capacity utilization rate data (DCN SE09071).

EPA disagrees with commenters who asserted that the plants permanently ceasing combustion of coal by 2028 and low utilization subcategories are not needed to ensure grid reliability. EPA also disagrees that finalizing these subcategories would create regulatory loopholes or allow facilities to disregard existing permit requirements. For EPA's response to these topics, see the responses

[41] *See also, e.g., Kennecott Copper Corp. v. EPA*, 612 F.2d 1232, 1241 (10th Cir. 1979) ("The choice of subcategorization methodology lies within EPA's sound discretion.") (citation omitted); *BP Exploration & Oil, Inc. v. U.S. EPA*, 66 F.3d 784, 802 (6th Cir. 1995) (upholding EPA decision that treated Alaska dischargers differently from other offshore dischargers in its Offshore Oil and Gas Effluent Guidelines).

to comment codes 9.a (Subcategorization - Retirements & Fuel Conversion by 2028) and 9.b (Subcategorization - Low Utilization).

EPA disagrees with commenters who stated that "EPA is proposing to allow unlined impoundments to serve as BAT" for low utilization plants and those ceasing combustion of coal by 2028. As described in section VII.C.2 of the preamble, EPA selected chemical precipitation as the technology basis for BAT limitations and PSES for FGD wastewater for low utilization EGUs. While EPA selected composite lined surface impoundments as the BAT technology basis for BA transport water for low utilization EGUs, this was combined with a BMP plan under section 304(e) of the CWA to further reduce the discharge of pollutants. In addition, as described in section VII.C.3 of the preamble, EPA selected surface impoundments as BAT for FGD wastewater and BA transport water for EGUs permanently ceasing coal combustion by 2028.

Subcategorization based on cyclone boilers

EPA disagrees with one commenter's request for a BAT subcategory for cyclone boiler slag transport water. As part of the 2015 rule, EPA revised the definition of bottom ash to specifically include boiler slag (see 423.11(f) - *The term bottom ash means the ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls. Economizer ash is included in this definition when it is collected with bottom ash.*). As explained in EPA's 2015 response to public comment, this update was made based on the specific request of many industry commenters, including the industry trade association, to include boiler slag in the definition of bottom ash (see EPA's response to EPA-HQ-OW-2009-0819-4633-A1 , Excerpt 46, DCN SE05958).

EPA continues to include boiler slag in the definition of bottom ash transport water as part of the final rule and takes the same position made as part of the 2015 response to public comment (see EPA's response to EPA-HQ-OW-2009-0819-4633-A1 , Excerpt 46, DCN SE05958). As such, EPA's BA transport water characterization dataset still includes data from at least two plants with impoundments receiving boiler slag in its loading analyses. Therefore, the data used in the analysis of bottom ash transport water are representative of water transporting both conventional bottom ash and boiler slag. EPA's review of the commenter's data actually shows that the average TSS and TDS concentrations are within the range of the TSS and TDS concentrations included in EPA's dataset supporting the final rule. Because high recycle rate systems still utilize a quench bath to cool bottom ash, these systems are available, and were determined to be economically achievable, for cyclone boilers.

Subcategorization based on plants with existing permits

EPA disagrees with the commenter who suggested EPA create a new subcategory for plants with existing permits that already incorporate the 2015 rule. EPA has made findings that specific technologies are BAT for control of BA transport water and FGD wastewater discharges for the reasons described in the preamble, and those reasons apply equally with respect to the control of discharges from plants that might have a permit already incorporating the 2015 rule. EPA also disagrees with commenters who suggested there may be significant costs with modifying NPDES permits that already contain limits based on the 2015 rule. Just because a permit was issued incorporating the 2015 rule does not mean that the permitting authority's work on that permit is no longer valuable. First, where a permitting authority has imposed more stringent requirements that are necessary to meet water quality standards than the limitations specified in this final rule, the final rule would not require revisions to those portions of the existing permits if the limits are still necessary to meet water quality standards. As described in the final rule, BAT limitations for BA transport water require a site-specific evaluation of purge volume that can be no greater than 10 percent of system volume, and effluent limits based on BPJ. In some cases, a modification of a permit to reflect BPJ limits established pursuant to the final rule may not necessarily result in less stringent BA transport water limits for particular plants.

Finally, EPA has finalized 423.19(h)(5), which allows for prior notice of opting to comply with the 2015 rule VIP to serve as a notice of planned participation in the VIP under the final rule. Given the text of some permits issued based on the 2015 rule, and the expiration date of those permits, it is possible that the permitting authority may not have to make any modifications to the FGD wastewater limitations in these permits prior to the reissuance timeframe. Rather, in some cases permitting authorities could wait to add the new VIP requirements to permits as they come up for reissuance.

9a <u>Subcategorization – Retirements and Fuel Conversion by 2028</u>

As described in section VII.C.3 of the preamble, under the final rule, EPA established a subcategory for electric generating units (EGUs) permanently ceasing the combustion of coal by 2028, based on the statutory factors of cost, the age of the equipment and plants involved, non-water quality environmental impacts (including energy requirements), and other factors as the Administrator deems appropriate. This response expands on the discussion in the preamble in order to address issues raised by public comments categorized as Code 9.a (Subcategorization – Retirements and Fuel Conversions by 2028). The response has been organized into subtopics; identified by subheadings in the response below. The response covers the following subtopics.

- General support for subcategorization.
- Notice of planned participation requirements.
- Timing for subcategorization.
- Support for including units repowering as part of this subcategorization.
- Subcategorization for retirements after 2028.
- Opposition to subcategorization.

For more information on EPA's evaluation of this subcategory, see EPA's *Steam Electric Effluent Guidelines Reconsideration – Evaluation of Final Rule Subcategories* memorandum (subcategorization memo, DCN SE09071).

General support for subcategorization

Many commenters expressed support for a subcategory in the final rule for plants planning to retire or repower in the near term. The final rule establishes a subcategory for EGUs permanently ceasing the combustion of coal by 2028. See section VII.C.3 of the preamble for EPA's rationale for including this subcategory in the final rule and EPA's subcategorization memo (DCN SE09071).

Notice of Planned Participation requirements

The proposed rule included a new subcategory for EGUs that plan to permanently cease combustion of coal no later than December 31, 2028, subject to a certification requirement. Some commenters stated that a more broad and flexible method for certifying commitment to the retirement subcategory is warranted. Other commenters stated that plants and EGUs should demonstrate periodic progress, rather than submit only a single certification statement that then requires permitting authorities to monitor or otherwise track progress until the 2028 compliance deadline. In response to these comments, EPA modified the reporting and recordkeeping requirements in the final rule to be more robust and more flexible than proposed. Specifically, under the final rule, plants are required to provide an initial Notice of Planned Participation, rather than an initial certification, and thereafter are required to submit to the permitting authority annual reports to document progress toward achieving the 2028 compliance deadline. See section XIV.B of the preamble for discussion of the reporting and recordkeeping requirements in the final rule.

Also in response to public comments and as described in Section VII.C.3 of the preamble, EPA revised the subcategory from "retired from service" to be those EGUs that will permanently cease the combustion of coal no later than December 31, 2028. For a complete list of the requirements for this subcategory, see 40 CFR 423.19(f).

Timing for subcategorization

EPA agrees with commenters that an eight-year time period is appropriate to complete generating unit retirement or repowering and disagrees with commenters who assert that a shorter or longer time period would be more appropriate. As described in section VII.C. 3 in the preamble, EPA selected the timeframe in the final rule because it allows time to build replacement capacity and allows for harmonization with the CCR rule. Specifically, the CCR Part A rule finalized alternative closure provisions under 40 CFR 257.103(f) for coal-fired EGUs that permanently cease operation and complete closure of their unlined surface impoundments by 2028. EPA disagrees with the commenters who assert that the intent for this subcategory was to promote the alternative closure provision in the CCR rule. Rather this subcategory is intended to align the CCR rule closure dates with any plants that may qualify for the retirement or repower subcategory under the final rule.

EPA disagrees with commenters who suggested that plants should have an additional two years or longer to opt into this subcategory. As described in section XIV.A.4 of the preamble, EPA is finalizing provisions allowing for a plant with a permit to transfer between subcategories, or between a subcategory and the VIP, without undergoing a permit modification, assuming the permit contemplates and allows this to occur. This includes electric utilities that may file a notice of planned participation (NOPP) in the retirement/repowering subcategory but then several years later determine that it is profitable to remain in operation either as a low utilization boiler or with treatment in place to meet the limits in the VIP. Under the final rule, utilities have options to transfer between applicable permit limitations under certain circumstances as outlined in 423.13(o)(1)(i) and 423.13(o)(1)(ii).

EPA disagrees with commenter's request for a two-year extension to the 2028 date if natural gas infrastructure issues delay the construction of a replacement natural gas combined cycle generating unit. Instead, as described in section 423.19(j), EPA has included a notice of material delay provision. This requires plants to notify the permitting authority within 30 days of a delay of milestones set forth in section 423.19(f) that may preclude compliance with the December 31, 2028 cessation of coal combustion requirement. As described in section XIV.C of the preamble, this does not change the 2028 date, but does provide the permitting authority adequate notice to seek resolution prior to the deadline for compliance.

Support for including units repowering as part of this subcategorization

EPA agrees with commenters who suggested that the subcategory should include all EGUs that would cease the combustion of coal, either through retirement or repowering, not just through retirement. EGUs that repower cease generation of BA transport water and FGD wastewater, just as retiring generating units do. As such, the final rule establishes a subcategory for EGUs permanently ceasing the combustion of coal by 2028. EPA agrees with commenters that revising the definition for this subcategory to include repowering EGUs is consistent with how EPA conducted its rulemaking analyses (i.e., treating both units retiring and repowering by 2028 the same). EPA acknowledges that not treating repowering as equivalent to closure could create an unfavorable incentive for a plant to, instead of repowering, retire and construct a new EGU on a greenfield site, rather than use existing infrastructure. The use of existing transmission and distribution infrastructure, where possible, can limit potential new impacts from greenfield project development.

Inclusion of repowering generating units also enhances harmonization of the rules applicable to this industry and gives greater clarity to the regulated community. As discussed in the CCR Part A final rule, the alternative closure provisions for "permanent cessation of the coal-fired EGU" in 40 CFR § 257.103(f)(2) includes EGUs that convert to natural gas or other fuels. To avoid the confusion, the final ELG subcategory adopts nearly identical terminology, which is slightly modified to avoid confusion, but which is intended to parallel the EGUs that would be able to satisfy 40 CFR § 257.103 of the CCR rule. Adopting the same approach for these ELGs will promote consistency and certainty for the regulated community.

See the response to Code 8 (Adjustment for CCR, CPP, and ACE Rules) for details on how EPA adjusted the analyses for the final rule to account for impacts of the CCR rule, including those plants that may be replacing their existing ponds with new, lined ponds.

Subcategorization for retirements after 2028

EPA disagrees with commenters who suggested that EPA should establish another subcategory for longer-term retirements. As discussed in the timing subsection above, EPA determined that the final 2028 timeframe is appropriate because it allows time to build replacement capacity and allows for harmonization with the CCR rule.

As described in EPA's subcategorization memo (DCN SE09071), EPA further examined the 24 EGUs that have announced retirement or fuel conversion after 2028. Of these 24 EGUs, only four EGUs at two power plants are projected to incur costs under the final rule. These four EGUs are currently expected to continue burning coal until 2033 and 2035, meaning that incremental changes to the closure year are unlikely to lead to significant changes in regulatory costs or pollutant loads. EPA notes that while it is possible additional power plants might choose to retire just after 2028 and have not yet announced their intent to do so, the Agency to predict these future decisions based on its rulemaking record.

Opposition to subcategorization

EPA disagrees with commenters who asserted that the sole basis for establishing this subcategory is cost and "the possible impact of those costs on continued facility operation." These commenters also asserted that the EPA does not have the authority to establish a subcategory for EGUs that are projected to retire because the CWA does not give it authority to establish a subcategory to "avoid premature closures" of plants. Response to comment code 9 provides the basic legal analysis in support of subcategorization under the Act. This subcategory is appropriately based on the factors of cost, the age of the equipment and plants involved, non-water quality environmental impacts (including energy requirements), and other factors as the Administrator deems appropriate.

One commenter stated that "EPA's assertion that the closure of certain units before their currently scheduled retirement date is 'premature' conveys an inappropriate and misinformed judgment about when such units *should* retire." At proposal, EPA reviewed reasons electric utilities cited when announcing plant closures and found that environmental regulations were cited by nearly one-third of these plants. Additionally, some specifically mentioned the ELGs, which suggests that additional flexibility may help to avoid premature closures of some plants and/or EGUs. EPA recognizes that plants need time to retire or repower and develop a plan for replacement generation.

EPA disagrees with the commenter who asserted that this subcategory is "creating a special exemption for the worst-performing plants" and that these generating units would be allowed to discharge highly toxic wastewater for up to eight years longer than otherwise allowed. EPA views this subcategory as inclusive of EGUs which have a limited amount of time to recoup costs but that may still be necessary for reliability until replacement capacity is constructed. It is also the case that some of these plants are planning retirement prior to 2028, therefore, it is not accurate that all plants in this subcategory will discharge wastewater for an additional eight years. As shown in EPA's industry profile, 35 generating units out of 46 that are designated as retire/repower between 2024 and 2028 announced a retirement date prior to 2028.

EPA disagrees with the commenter who asserted that subcategorizing on this basis would "open the Agency up to countless requests for subcategories based on differences in the profitability of various plants" and that this subcategory is not practically enforceable. A subcategory can only be established in an ELG if it is supported by the rulemaking record based on the statutory factors. See *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 214 (5th Cir. 1989) (stating that EPA is required to create a separate subcategory for a group of plants only when they are so fundamentally different from other plants on which the limitations are based that they cannot achieve the effluent limitations). The requirements for this subcategory outlined in 40 CFR § 423.19(f), 423.13(o)(1)(i), and 423.13.(o)(1)(ii) hold electric utilities accountable for retiring/repowering according to their projections or require the plant to comply with applicable limitations, which are as enforceable as any limitations established in these ELGs. EPA notes that, as part of the NOPP, electric utilities will have a requirement to submit an annual report about the progress of the retirement/repower to their permitting or control authority.

EPA disagrees with commenters who suggested that it failed to consider the broader suite of statutory factors when analyzing this subcategory. In developing the final rule, EPA analyzed the impacts of regulatory actions affecting the electric power sector, updating the analysis to include EGUs projected to be in this subcategory. Specifically, EPA evaluated these EGUs in IPM for the final rule (see section VIII.C.2 of the preamble) and reviewed the impacts on energy requirements/electric reliability (NWQEI). EPA carefully considered all of the statutory factors and as described in section X of the final rule preamble, the subcategory is based on cost, the age of the equipment and plants involved, non-water quality environmental impacts (including energy requirements), and other factors as the Administrator deems appropriate.

EPA rejected subcategorization of retiring units in 2015 in part because the 2015 rulemaking record did not demonstrate that age or location of a plant or generating unit by themselves affected the ability of the plant to install and operate treatment technologies established in that rule. (2015 Response to Comments, EPA-HQ-OW-2009-0819-6469) For this final rule, EPA also evaluated age in terms of remaining life of the plant and found that units with a limited remaining life would incur disparate costs and contribute to unacceptable non-water quality environmental impacts if forced to meet the generally applicable BAT limitations. Courts have held that EPA has considerable discretion in how to evaluate the statutory factors and the weight accorded each factor. *See, e.g., Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) ("The EPA nonetheless has considerable discretion in evaluating the relevant factors and determining the weight to be accorded to each in reaching its ultimate BAT determination. Thus, the EPA has significant leeway in determining how the BAT standard will be incorporated into final ELGs.") (citing *Natural Resources Defense Council v. EPA*, 863 F.2d 1420, 1426 (9th Cir.

1988)); *Weyerhaeuser Co. v. Costle*, 599 F.2d 1011, 1028, 1042 (D.C. Cir. 1978) ("[T]he listing of factors seems aimed at noting all of the matters that Congress considered worthy of study before making limitation decisions, without preventing EPA from identifying other factors that it considers worthy of study. So long as EPA pays some attention to the congressionally specified factors, the section on its face lets EPA relate the various factors as it deems necessary."). Given the discretion EPA is afforded to consider the statutory factors, a court may uphold as reasonable more than one policy choice under the statute.

See EPA's response to Code 9 (Subcategorization)for more information on EPA's cost estimates for this subcategory.

EPA carefully considered non-water quality environmental impacts including energy requirements in making its decision to subcategorize units ceasing combustion of coal by 2028. First, EPA evaluated the potential impact on electric grid reliability by reviewing an aggressive stress test scenario recently conducted by North American Electric Reliability Corporation (NERC) identifying the reliability risks associated with early retirements. The report conveyed to EPA that the well-planned construction of new generation capacity and orderly retirement of older power plants are vital to ensuring electricity reliability. See Section VII.C.2 of the final rule preamble. Second, EPA evaluated the most recent summer and winter reserve margins. Finally, EPA evaluated commenter-provided examples of localized electricity upsets. Taken as a whole, these sources of information indicate that EGUs nearing the end of their useful life (either because they will retire or repower) still have an important role to play in ensuring electric reliability (DCN SE09071). See section VII.C of the final rule preamble and section 7 of the TDD for further discussion.

EPA disagrees with commenters who suggested that this subcategory may decrease the appeal of the VIP. Both the subcategory and VIP program are options for electric utilities to consider when determining how to comply with the final rule. Where the costs of membrane filtration (or other VIP-compliant technology) are less than the costs of CP+LRTR, it may allow plants to remain in service longer than were there no VIP, and regardless, both alternatives (VIP and permanently cease coal combustion) will result in significant reductions in pollution post-2028.

See EPA's subcategorization memo for additional information on EPA's evaluation of compliance costs and available treatment technologies (DCN SE09071). EPA agrees with commenters who suggested that EPA should have evaluated the costs and pollutant loadings of EGUs that fall into this subcategory. In response to these comments, EPA incorporated all EGUs retiring and repowering after 2023 (the latest compliance deadlines in the 2015 rule) in baseline and the regulatory options evaluated for the final rule. For those EGUs that would be subcategorized as permanently ceasing coal combustion by 2028, EPA evaluated the changes in costs and pollutant loads under the final rule.

9b Subcategorization – Low Utilization

EPA disagrees with comments suggesting that EPA's use of disparate costs are not a statutorily permissible basis for subcategorization. For further discussion of the CWA and use of disparate costs to subcategorize, see responses to comment Code 1 (Legal Authority). EPA further disagrees with commenters' statements that costs are not disparate for reasons discussed below, for details on EPA's cost methodology see Section VII of the preamble and Section 5 of the Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental TDD) (EPA-821-R-20-001). First, costs are appropriate to consider on an electric generating unit (EGU) basis and it is appropriate to consider these costs across all wastestreams. In the Steam Electric Effluent Guidelines Reconsideration - Evaluation of Final Rule Subcategories memorandum (DCN SE09071) EPA discusses other EPA regulations which apply more flexible regulatory requirements on an EGU basis. More importantly, the final rule applies to generating units, and EPA has differentiated on an EGU basis in this very rule. See 40 CFR § 423.10. In 2015, EPA established a subcategory for EGUs with a nameplate capacity less than 50 MW based, in part, on disparate costs of the entire rule (i.e., costs for all covered wastestreams).42 Second, while EPA agrees that with the revisions made to the final rule, there would have been cost savings to low utilization units without adding subcategorization, EPA's record demonstrates that these lower costs would have still been disproportionate to low utilization electric generating units (LUEGUs). With regards to the commenter that stated EPA ignored the "very real possibility that the relationship between cost and generation is different for the two treatment technologies," as discussed in preamble section VII.C.2, capital costs do not vary with generation of electricity. Therefore, the Agency evaluated the annualized capital costs yet to be incurred. Finally, EPA disagrees with commenters who assert that the disproportionate costs for LUEGUs should be found acceptable because the costs can be reasonably borne by the industry as a whole (LUEGUs and non-LUEGUs). When EPA finds it appropriate to subcategorize, it considers the statutory factors with respect to the particular subcategory. See also EPA's response to comments in Code 1 (Legal Authority). Thus, it is not determinative that the commenters' IPM run shows what they believe to be small impacts to the whole industry. EPA also finds the commenters' IPM run does not account for several important changes which the Agency made to several final rule analyses (e.g., inclusion of the impacts of CCR Part A).

With respect to the evaluation of non-water quality environmental impacts, EPA agrees with factual statements made by commenters on both sides of the issue, but the Agency concludes that these facts support subcategorization. Commenters who believed electric reliability concerns are unwarranted cited to the competitiveness of other fuel sources, the startup times of coal-fired EGUs, minimal incremental retirements in EPA's own IPM results, existing reserve margins, and the integrated resource planning process. However, these comments overlook several additional aspects of electric reliability. First, these comments focus on NERC regions with adequate reserve margins and ignore NERC regions and subregions with lesser reserve margins including one region (ERCOT) that was not anticipated to meet its reference margin. Second, electric utility commenters provided examples of localized grid issues where having coal-fired LUEGUs for load balancing may provide grid resilience, even in locations where required reserve margins

[42] EPA notes that commenters did not challenge this subcategory in *Southwestern Electric Power Company v. EPA,* 920 F.3d 999 (5th Cir. 2019).

are being met. Finally, the integrated resource planning process, which these commenters believe supports their claim that reliability concerns are overstated, in some cases, forecasts the retention of LUEGUs for reliability. For example, Georgia Power's 2019 IRP stated:

> *In this IRP, the Company is proposing to retire an additional 982.5 MW of coal capacity at Plants Hammond and McIntosh. These retirements are also in the best economic interests of customers, and do not impact the Company's ability to maintain a sufficient reserve margin. However, these units have been called into action over the past several years and have aided the resilience and reliability of the System since the 2016 IRP, all while under spending limitations. As future coal retirements remain possible, the Company will need to balance the economic benefits of retirement and the ability to take advantage of low-cost gas commodity prices against the potential risk associated with gas fuel supply. Striking the right balance requires consideration of numerous options such as energy storage, inactive reserve, or fuel storage, which may preserve on-site fuel while minimizing spend. These items could prove to be an important resilience consideration with respect to potential future retirement decisions…*[43]

For further discussion of EPA's consideration of electric reliability, see the Steam Electric Effluent Guidelines Reconsideration - Evaluation of Final Rule Subcategories memorandum (DCN SE09071) and section VII.C.2 of the preamble.

EPA disagrees with commenters who asserted that the Agency erred in the statutory factors that it considered. First, EPA considered all statutory factors, and focuses its preamble discussion on the factors which distinguish LUEGUs in this subcategory from those EGUs to which the generally applicable BAT limitations apply. With respect to comments that EPA did not fully consider non-water quality environmental impacts of changes in air pollution, EPA disagrees. EPA evaluated air pollution changes at proposal, and has further modeled the expected air pollution benefits for the final rule. See section 2.4 of the Benefits and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA) (EPA-821-R-20-003) for benefits analysis. EPA also explicitly considered subcategorization on the statutory factor of "age." While EPA agrees that consideration of age is relevant, and has relied on this factor in establishing BAT in other ELGs, EPA rejected it as a basis for the LUEUG subcategory, as discussed in Section 5.2.1 the 2015 *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-15-007). With respect to the comments citing the need for a megawatt hour threshold to prevent an l increase in probability of retirement, EPA notes that costs imposed by the ELGs have decreased as a result of the continued closure of surface impoundments under the CCR rule. EPA has explicitly modeled these combined impacts in IPM as discussed in Chapter 5 of the Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA) (EPA-821-R-20-004). Thus, EPA considered retirements, though the Agency did not conclude that the impact on premature

[43] Ga. Power Co., 2019 Integrated Resource Plan C-28, Ga. Pub. Serv. Comm'n Docket No. 42310 (2019).

retirements was disparate for this subcategory of plants. With respect to the commenter who encouraged "EPA to consider the potential benefits of the Low Utilization Subcategory to rural communities that cannot easily diversify their economies and are dependent on coal-fired units for substantial revenues," EPA considered the issue of employment impacts in Chapter 6 of the RIA. Since EPA conducted a nationwide analysis, these impacts were not separately analyzed for individual localities, and furthermore commenters did not provide data that would allow EPA to do so. With respect to commenters' argument to not impose limitations on this subcategory asserting relatively lower pollutant discharges of these facilities, EPA does not consider costs in comparison to pollutant reductions (see response to comment Code 1 (Legal Authority)).

EPA agrees with commenters who stated that a CUR-based threshold for this subcategory is the most appropriate for the reasons discussed in section VII.C.2 of the preamble. Thus, EPA disagrees with commenters who suggested alternative production thresholds, including comments that suggested specific approaches for implementing the MWh production threshold.44 The remaining responses below respond to comments on the implementation of a MWh-based production threshold which EPA still finds relevant to the CUR-based threshold.

EPA disagrees with commenters who suggested alternative technologies as BAT for this subcategory. EPA rejects surface impoundments as a BAT basis for FGD wastewater because the selected chemical precipitation technology removes additional dissolved pollutants such as mercury, arsenic, and lead. This technology is available, economically achievable for the subcategory, and imposes acceptable non-water quality environmental impacts. While some commenters suggested that chemical precipitation would still impose disproportionate costs, EPA disagrees. After accounting for the closure of unlined surface impoundments under the CCR rule, the costs estimated for chemical precipitation are substantially less than the costs for CP+LRTR required for the rest of the industrial category.45 In contrast, EPA concludes that lined surface impoundments are BAT for BA transport water for the reasons presented in section VII.C.2 of the preamble. While some commenters argued that the selection of surface impoundments as BAT violates the law, EPA disagrees, and a discussion of this issue is presented in responses to comment Code 1 (Legal Authority). EPA also disagrees that it did not consider alternate technologies. EPA evaluated the costs of several technologies (including those selected in the 2015 rule) in Section 5 of the Supplemental TDD, and has further evaluated the costs, benefits, and economic impacts of other technologies for LUEGUs in Options B and C. Finally, some commenters found EPA's technology selection to be troublesome because they assert that it would not make sense to have multiple EGUs subject to different limitations where a treatment system is shared. EPA agrees that shared treatment systems are likely in certain situations where they result in reduced costs. To the extent that facilities find it cheaper or easier to install a single treatment system that removes more pollutants, nothing in the final rule would prohibit this result. Finally, some commenters dispute the Agency's HRTR cost estimates and limitations for the LUEGU subcategory. For further discussion of EPA's HRTR cost estimates,

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[44] These included alternative MWh thresholds, flexibilities for comparable flows, multi-EGU averaging at a plant, treatment of dual-fired EGUs, and a three-tier approach further dividing the subcategory.

[45] EPA also notes that few LUEGUs have FGD wastewater (DCN SE08638).

see Code 15 (FGD Wastewater – CP+LRTR and CP+HRTR). For further discussion of the calculation of limitations, see Code 43 (Numeric Limitations).

With respect to implementation, EPA finalized the permit conditions of proposed section 423.18. While the low utilization subcategory threshold has changed to a CUR rather than a generation threshold, EPA continues to find that additional utilization from these units may be justified in limited circumstances, including as discussed in preamble section XIV.A.5. Similarly, EPA has finalized the threshold based on at the most recent two years of data to account for fluctuations in year-to-year operations. While some commenters asserted this could lead to abuse, EPA disagrees. At most, the use of a 24 months of data to determine annual CUR would allow an EGU to operate at a 20 percent CUR for one year but then not operate at all for the year prior to or after this increased operation. The 20 percent CUR equates to between two and three months of operation, but is unlikely given the extreme result that the EGU would not be able to operate for a year on either side and still qualify for the subcategory. Furthermore, if an EGU exceeds the CUR limitation over any two-year period, it would be out of compliance with its permit, and potentially subject to enforcement action under the CWA. EPA disagrees with commenters who asserted that additional flexibility is necessary for winter energy demands. EPA did not make exceptions for this type of operation in the other regulations discussed in the Steam Electric Effluent Guidelines Reconsideration - Evaluation of Final Rule Subcategories memorandum (DCN SE09071). While an EGU may have to operate for limited periods to generate heat, operators can plan for this and determine in advance whether an EGU is likely to be low utilization.

A number of additional comments requested changes in the timing and requirements to commit participating in the LUEGU subcategory. EPA agrees with many of these comments. The final rule establishes reporting and recordkeeping requirements that are more flexible than proposed, while still providing sufficient information to the permitting authority for seeking inclusion into the LEUGU subcategory. For instance, power plants are initially required to submit a NOPP due by December 31, 2023. This allows for power plants to consider future utilization where utilization is expected to decrease from current operations, thus addressing some commenters' concerns that the proposed certification was too inflexible, that additional time was needed to certify to low utilization, that changes to section 423.11(t) may be necessary, and that the tight reporting requirements would discourage EGUs from certifying to low utilization. In response to the commenter requesting certification on when annual certification was required, annual certification is required 60 days after submitting data to the Energy Information Administration (see 423.19(e)(3)). Additionally, EPA has finalized section 423.13(o), which allows for transition between subcategories where the permit authorizes it. This addresses commenters' requests that EPA harmonize the timing with the subcategory for EGUs permanently ceasing coal combustion and create suitable off-ramps where utilization circumstances change. This flexibility ultimately expires, but in the short-term will allow facilities to complete their integrated resource planning process before permanently committing to a course of action. For example, a facility considering retirement may later opt into the VIP should the IRP process conclude that continued operation of an EGU is necessary. See section XIV.B of the preamble for further discussion of the reporting and recordkeeping requirements in the final rule.

EPA disagrees with commenters who argued that the submission of information to the control authority is inappropriate. As discussed in section XIV.A.1 of the preamble, the control authority is responsible for the development of the specific discharge limitations for the POTW's industrial users, and information pertaining to any subcategories would necessarily factor into such limitations.

One commenter suggested that the best management practice (BMP) plan inspection frequency be based on a plant's professional engineer's analysis of risk and consequences, but the commenter did not provide examples of any "risk or consequences" to consider, nor why those considerations would suggest that less frequent inspections are appropriate. The BMP plan inspection requirements are being finalized as proposed.

Finally, the comment requesting EPA to modify the 2015 rule subcategorization for EGUs less than 50 MW nameplate capacity are outside the scope of this rulemaking.

9c Subcategorization – High FGD Wastewater Flow

With respect to general comments, EPA agrees with those comments expressing support for the subcategory and disagrees with those opposed to the subcategory. To the extent that these commenters raised specific comments, the Agency responds to these comments below.

EPA disagrees with the comments raised on the legality of the high flow subcategory in the final rule. See comment code 1 for additional response to legal comments. To the extent that commenters asserted that EPA failed to evaluate all of the statutory factors, EPA disagrees. These commenters confuse EPA's evaluation of the statutory factors with the explanation in the final rule preamble of which factors the Agency found are disparate for this subcategory. In evaluating all of the statutory factors, EPA found that, for high flow facilities, compliance with any technology more stringent than chemical precipitation would result in unacceptable disparate costs, and warranted subcategorization as discussed in Section VII.C.1 of the preamble.

While EPA agrees with commenters that it made certain findings in the 2015 rule, the Agency disagrees that it has reversed those findings in the final rule. The recycle rates for the Cumberland plant that were discussed in the 2015 rule record were shown to be slightly higher than what TVA provided in its subsequent FDF variance request. For the final rule, EPA used the recycle rate provided in the FDF variance request. EPA estimated TVA's costs to comply with the regulatory options, based on this small amount of recycling incorporated, as discussed in Section 5 of the Supplemental TDD. Thus, commenters misinterpret the Agency's findings. The 2015 findings on perverse incentives are also misrepresented by commenters. The final rule explicitly requires the four million gallon per day (GPD) flow rate to be determined after accounting for recycling. Thus, a facility increasing its flow to get to four million GPD would fail to satisfy this aspect of the ELG, preventing circumvention of the generally applicable limitations. Because the final rule would not encourage the increase in flow rates at other power plants, there would be no increase in water usage, and thus no unacceptable NWQEIs. Finally, "reasonable further progress" must be analyzed in the context of the statutory factors. EPA has evaluated all of the statutory factors for this subcategory. Based on the disparate costs identified by EPA and discussed in section VII.C.1 of the final rule preamble, EPA found that BAT for FGD wastewater at high FGD flow power plants was chemical precipitation. In light of the current use of surface impoundments at the Cumberland plant and considering the statutory factors, chemical precipitation makes reasonable further progress for at this plant by removing dissolved pollutants such as mercury and arsenic. These pollutant load reductions would occur at any plant eligible for the high flow subcategory that currently operates surface impoundments but would be required to install chemical precipitation under the final rule. Furthermore, EPA disagrees in part with comments that the mercury limitation is 10 times that of the rest of the industrial sector. While the removals from CP+LRTR are lower, the removals of the biological stage are irrelevant here where EPA has determined that CP on its own is BAT. The limitations are based on the same CP system described in the 2015 rule, and thus it has correctly established the same limitations for mercury and arsenic for this subcategory in the final rule.

EPA agrees with commenters that a power plant is not required to install the specific technology that is the basis for BAT. However, as discussed below, EPA finds that alternative technologies do not eliminate the disparate costs that led to the creation of this subcategory in the first place. Finally, EPA agrees that economic achievability for a category or class of point sources is required for selecting a technology as BAT. However, EPA is also statutorily required to consider "cost," and EPA has previously considered disparate costs to subcategorize a BAT regulation which is otherwise economically achievable to the industrial sector. Specifically, in the 2015 rule, EPA subcategorized EGUs with a nameplate capacity below 50 MW based on disparate costs and the same commenters did not challenge this provision of the 2015 rule. See *Southwestern Electric Power Co. v. EPA,* 920 F.3d 999 (5th Cir. 2019).

With respect to comments on additional statements made in TVA's FDF variance request and 2019 Environmental Assessment which were not discussed above,[46] EPA did not rely on these additional statements from TVA in establishing the high FGD flow subcategory. Instead, EPA has established this subcategory for the reasons discussed in Section VII.C.1 of the preamble.

EPA disagrees with commenters who asserted that it made errors in its analysis. As far as the flow assumptions and their effect on cost, EPA notes that it accounted for TVA Cumberland's ability to recycle in the Agency's O&M cost estimates. Commenters are further incorrect in asserting that the flows used for capital costs are incorrect. While Cumberland may generate an average flow lower than the four MGD set as the threshold, even the commenters' analysis shows that the facility, at times, produces at or near its nameplate capacity, and thus has these high flows. To assume that a facility could simply install an equalization tank and ignore these maximum flows is an oversimplified assumption. While this might be possible for a single day of higher flows, any multi-day utilization resulting in these high flows would quickly overwhelm

[46] Tennessee. Valley Authority. 2019. Cumberland Fossil Plant (CUF) Wastewater Treatment Facility Final Environmental Assessment. July.

any extra equalization tank volumes. Instead, EPA chose to use this flow rate for capital costs to ensure that installed treatment technologies would be able to accommodate the maximum possible FGD purge flow, and to estimate O&M costs, EPA used optimized FGD flow rates, recognizing that well-operated plants would take steps to optimize the volume of water to be treated and normalize the flow where possible, which will allow for more realistic annual cost estimates. As far as competitiveness and reliability, EPA agrees in part with commenters that Cumberland has seen a decreasing utilization over time and may not be needed for future reliability; however, this was not a basis for EPA creating this subcategory and thus does not cause EPA to change its conclusion that subcategorization is warranted on the basis of disparate costs.[47]

Some commenters asserted that EPA failed to consider alternative technology options for this subcategory. EPA disagrees and notes that the Agency evaluated more alternatives for the Cumberland plant in the final rule. At proposal, in addition to CP, EPA explicitly estimated costs for CP+LRTR, CP+HRTR, membrane filtration, and thermal technologies (see section 5.2 of the 2019 Supplemental TDD). While EPA did not include these alternative subcategory costs in its proposed regulatory options where it had focused additional analysis, they were fully considered. For the final rule, EPA has continued to evaluate these same technologies. In the analysis supporting the final rule, the subcategories only apply to Option A, and not under options B or C. Thus, where EPA has focused additional analysis on these regulatory options, it now includes some of these alternative technologies as commenters have requested.

Two alternatives explicitly listed by commenters also warrant discussion: changes to Cumberland's air pollution controls and coal switching. EPA disagrees with commenters that either alternative has been demonstrated to be feasible at the Cumberland plant. With respect to changes to the FGD system itself, EPA notes that the commenters provided no data supporting their assertions that the FGD system can be either replaced or upgraded at a lower cost than EPA's current wastewater treatment estimates. FGD systems can cost hundreds of millions of dollars, and EPA declines to speculate that TVA can reduce its compliance costs by making changes to such an expensive system based solely on commenters' unsupported statement. Commenter suggestions that EPA should evaluate coal switching are also overstated. While commenters suggest that simply switching to powder river basin (PRB) coal would result in reduced air pollution and allow for additional recycling of FGD wastewater, they fail to acknowledge that the use of a different coal may prevent the facility from meeting its requirements under Mercury Air Toxics Standards (MATS). In meetings with EPA, electric utilities stated that there may be sufficient halogens in bituminous coals to meet MATS; however, at least a couple of plants burning PRB coal represented the opposite, that additional halogen addition was required to maintain compliance with MATS. Thus, if TVA were to simply

[47] Furthermore, this does not indicate that the plant is not competitive, merely that it is no longer among the most competitive sources of electricity during periods of base load demand. And while the commenters are correct that this facility may not be necessary per se for reliability in its NERC region (which has sufficient reserve margins), that does not mean that it cannot serve useful load balancing in its sub-region or fill needs during situations where other power plants have to go offline unexpectedly (see e.g., discussion in Section VII.C.2 of the preamble).

switch coals at the Cumberland facility, not only would its cost increase for the coal, but it may incur additional costs to comply with MATS, costs which may also require the addition of halogens which these same commenters find problematic elsewhere. EPA disagrees that switching coals has been shown to be a less costly alternative, and without further evidence from the commenters or data in the rulemaking record, declines to change its findings that the costs on high FGD flow facilities are disproportionate.

EPA disagrees with one commenter's suggestion to include an additional high recycle rate subcategory. FGD systems which are able to recycle most or all of their wastewater would have much lower costs under the final rule as they would be able to design treatment systems that manage much smaller average and maximum volumes. Since EPA has already considered these recycle rates in its analysis of the statutory factors, the Agency confirms its conclusion that consideration of the statutory factors result in CP+LRTR being BAT for FGD wastewater at such facilities.

10 Surface Impoundments

Surface Impoundments as a Control Technology

Some commenters asserted that surface impoundments cannot be BAT because EPA largely rejected surface impoundments as BAT in the 2015 rule. One commenter pointed out that the 2015 rule preamble stated that surface impoundments "are largely ineffective at controlling discharges of toxic pollutants and nutrients" (80 FR 67,840). EPA clarifies that this statement from the 2015 rule refers predominantly to the soluble (dissolved) form of pollutants. EPA finds that surface impoundments are capable of reliably and consistently achieving limitations on Total Suspended Solids (TSS), have been installed to treat most of the different steam electric power plant wastestreams, and have been meeting TSS limits at plants for decades. TSS can include many constituents, including particulate forms of metals such as mercury or selenium. In this final rule, after consideration of the statutory factors, in the limited instances where EPA is identifying surface impoundments as the BAT technology, EPA is establishing limitations on TSS. These limitations are expected to reduce the amount of particulates, including particulate forms of metals and any pollutants adsorbed to particulates, that will be discharged to surface waters. The removal of particulate pollutants is expected to occur even in surface impoundments that may experience conditions that could convert particulate forms of metals to soluble forms (e.g., low pH), surface impoundments that receive FGD wastewater, or during seasonal turnover.

Moreover, while it is true that more advanced wastewater control technologies than surface impoundments are available and achievable as defined by the CWA for discharges of pollutants from many electric generating units, that does not hold true for all such units. What is considered Best Available Technology Economically Achievable is determined only after consideration of a list of statutory factors, which includes cost, age of equipment and facilities employed, non-water quality environmental impacts (including energy requirements), as well as other factors the Administrator deems appropriate. *See* 33 U.S.C. §§ 1311(b)(2)(A), 1314(b)(2)(B).

It is important to note that, just because EPA in 2015 rejected surface impoundments in favor of other technologies for certain wastestreams stating that surface impoundments "would not result in reasonable further progress toward eliminating the discharge of all pollutants, particularly toxic pollutants," does not mean that surface impoundments can never constitute BAT (see, e.g., FN 4, below). Those statements were made in a context where technologies other than surface impoundments were found to be available and achievable in light of the requisite statutory consideration factors. In this case, for certain subcategories of units, EPA finds that other technologies are not available and achievable within the meaning of the Act, and surface impoundments are the technology that reflects BAT. *See* 33 U.S.C. § 1311(b)(2)(A).

Commenters' statements that BAT must be "based on the best-performing plant for that subcategory" do not conflict with EPA's decision to select surface impoundments as the BAT technology basis for discharges from certain subcategories because "best" is not limited to one meaning, and in fact is defined by the statute with reference to statutorily required factors, which include those considered by EPA in establishing these subcategories. In other words, in this case, EPA determines that the "best" performing plant for the relevant subcategories is the one using a surface impoundment to control discharges of FGD wastewater and BA transport water for the reasons explained here and in the preamble. *See Entergy Corp. v. Riverkeeper, Inc*., 556 U.S. 208, 218 (2009) (stating that the term "best" in section 316(b) does not necessarily refer to the one that produces the most of some good (e.g., reduction in adverse environmental impact)). *See also BP Exploration, et al v. EPA*, 66 F.3d 784, 796, 800 (6th Cir. 1995) (In upholding EPA's rejection of reinjection based on total industry cost, the court said, "[t]he CWA's requirement that EPA choose the 'best' technology does not mean that the chosen technology must be the absolute best. Obviously, BAT and NSPS must be acceptable on the basis of numerous factors, only one of which is pollution control.").

In the final rule, EPA finds that, for discharges of pollutants found in FGD wastewater or BA transport water from EGUs permanently ceasing combustion of coal by 2028 and in BA transport water from low-utilization EGUs, technologies other than surface impoundments (such as high recycle rate systems or chemical precipitation and/or biological treatment) would result in unreasonably high costs[48], unacceptable non-water quality environmental impacts (including energy requirements), and/or inconsistency with regulation of the steam electric power generating industry under the CCR rule. For these reasons, EPA determines that surface impoundments – which are technologically available and economically achievable, do not result in disproportionate costs or unacceptable non-water quality environmental impacts (including energy requirements), and allow for alignment with other applicable regulations – represent Best Available Technology Economically Achievable for discharges of pollutants found in FGD

[48] With respect to comments concerning EPA's use of cost as a basis to subcategorize plants or units, please refer to the comment response to comments in code 1 (Legal).

wastewater or BA transport water from EGUs permanently ceasing combustion of coal by 2028 and in BA transport water from low utilization EGUs.[49]

Subcategory for Units Permanently Ceasing Coal Combustion by 2028

As described in Section VII.C.3 of the preamble, EPA is establishing a new subcategory for EGUs that plan to permanently cease combustion of coal no later than December 31, 2028, subject to a Notice of Planned Participation (NOPP) submission requirement (see section XIV.A.3 of the preamble). For this subcategory, EPA is establishing BAT limitations on TSS for both FGD wastewater and BA transport water based on surface impoundments as the selected technology basis. EPA has authority to establish different limits for such EGUs to help avoid unacceptable impacts, after considering the statutory factors of cost, the age of equipment and facilities involved, non-water quality environmental impacts (including energy requirements), and other factors that the Administrator deems appropriate (see Section VII.C.3 of the preamble for more details).

EPA disagrees with the commenter who asserted that the Agency has "deem[ed] surface impoundments to be BAT without any discussion of what treatment technologies are already in use among the plants in this subcategory, what the best-performing plant is able to achieve, or any of the other standard methods that EPA uses to implement its statutory duty." EPA evaluated treatment technologies employed at plants that have EGUs that qualify specifically for this subcategory. See the details of EPA's evaluation in Section VII.C.3 of the preamble. While some plants that have EGUs scheduled to retire between 2024 and 2028 operate chemical precipitation or chemical precipitation followed by biological treatment to treat FGD wastewater or high recycle rate systems for bottom ash transport water, the fact that more advanced treatment technology already operates at these few plants does not demonstrate that all plants scheduled to retire would not incur disproportionate costs. In fact, the shortened amortization time at plants scheduled to retire increases the costs incurred to comply with the final rule relative to plants that are not scheduled to retire. *See Chemical Mfrs. Ass'n v. NRDC,* 470 U.S. 116, 120 (1985) (subcategories are necessarily rough-hewn); *Kennecott Copper Corp. v. EPA,* 612 F.2d 1232, 1241 (10th 1979) (rough basis for subcategorization suffices); *BASF Wyandotte Corp. v. Costle,* 598 F.2d 637, 655 (1st Cir. 1979) (plants within subcategories need not be identical and in fact may have production outputs that differ by a factor of fifty).

Another commenter asserted that EPA "has not even evaluated what other technologies would cost for units in this subcategory; it has instead summarily determined that any technology, other

[49] Here, EPA has explained its decision to select surface impoundments as BAT, as well as its decision that other technologies could not serve as BAT. See section VII of the preamble to the final rule for more detailed explanation for EPA's selection of surface impoundments for these subcategories. Thus, this rule is distinguishable from the 2015 rule, in which the Fifth Circuit faulted EPA for failing to explain why surface impoundments were BAT for discharges of legacy wastewater, as well as why other technologies were rejected based on the statutory factors. *Southwestern Electric Power Co. v. EPA*, 920 F.3d 999, 1018 n.20 (5th Cir. 2019) ("The record fails to explain why impoundments are BAT, if that term is to have any meaning. Furthermore, if chemical precipitation or biological treatment are technically feasible but simply too costly for treating legacy wastewater, the EPA could have said so. It did not.").

than the most primitive, imposes disproportionate costs." EPA disagrees with this comment. While EPA had general information about the costs of various technologies (e.g., chemical precipitation, LRTR, membrane) at proposal, EPA did not present unit-level costs for those in this subcategory. To address this, Section 5 of the Final Supplemental TDD includes evaluation of costs of the technology options evaluated for the final rule for this subcategory of facilities. Furthermore, EPA now specifically evaluates costs for these units under Options B and C; with plants installing CP+LRTR (with no subcategories) or membrane filtration for FGD wastewater and high recycle rate system for bottom ash transport water. A list of units permanently known by EPA to be ceasing combustion of coal between 2024 and 2028 is presented in *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule* memorandum (DCN SE08688). Twenty-two units at 11 facilities would be projected to incur costs under the final rule absent a subcategory for units permanently ceasing coal combustion by 2028.[50] Under Option B, these units combined have estimated capital costs of $209 million and estimated O&M costs of $21 million per year, leading to combined annualized compliance costs as high as $63 million per year.[51] When compared to the costs/MWh for EGUs not ceasing coal combustion by 2028, the shorter amortizations periods for these low utilization EGUs lead to disproportionate costs/MWh in some cases. Estimated costs for these facilities to comply under Option C are much higher than under Option B.

EPA reviewed options for this subcategory to lease treatment systems instead of incurring capital costs with a short amortization period; however, the Agency received only limited information regarding costs of leasing FGD wastewater treatment systems. EPA had conversations with several vendors and plants regarding leasing treatment equipment, but only obtained specific costing data for a single Duke Energy facility. EPA used the information provided in follow-up correspondence with Duke Energy to evaluate leasing in *Costs to Lease Flue Gas Desulfurization Wastewater Treatment memorandum* (DCN SE08633). EPA is aware of some vendors that offer their systems for lease. Comments from vendors including Purestream and Frontier Water Systems mention leasing FGD treatment systems but neither comments provide cost data associated with leasing the system. EPA followed up with Purestream more specifically related to their comments on the proposed rule, and discussed their business model in detail, which is based on leasing treatment systems (DCN SE08590). Purestream declined to provide details on costs associated with its thermal treatment system; therefore, without costing data with which to fully analyze the costs of leasing membrane or thermal treatment systems, EPA is unable to use this option in its compliance cost estimates.

With respect to consistency with the U.S. Court of Appeals for the Fifth Circuit's decision in *Southwestern Electric Power Company v. EPA*, please refer to the first paragraph, above, as well as the response to comments in code 1. Some facilities may be required to cease the use of existing surface impoundments under the CCR rule, but others could continue to operate until the

[50] Three boilers at two plants are expected to retire or cease burning coal between permit renewal and the no later than compliance date (December 31, 2028).

[51] This upper bound assumes costs are all incurred between 2021 and the announced year of closure or conversion to a different fuel source.

plant ceases combustion of coal, and the Subcategory for Units Permanently Ceasing Coal Combustion by 2028 in the ELG is intended to match extension flexibilities included in the CCR Part A Rule. The CCR Part A rule addresses unlined surface impoundments for the steam electric industry, establishing a new deadline of April 11, 2021, for all unlined surface impoundments to stop receiving waste and begin closure or retrofit. However, the CCR Part A rule also includes two flexibilities in sections 257.103(f)(1) and (f)(2). One flexibility is a site-specific extension provision that allows a facility to get extensions as late as 2023 or 2024 depending on whether the facility was already required to close prior to the *USWAG* court mandate. The other flexibility allows a facility to continue using its unlined surface impoundments until the boiler ceases coal combustion and the surface impoundment closes, which must both occur by 2028. See Sections VII.C.3 and VII.D in the preamble for more information.

Subcategory for Low Utilization EGUs

EPA disagrees with the commenter who asserted that this "proposal would allow numerous facilities in the Southeast to avoid more protective pollution limits and continue using their unlined lagoons for bottom ash." In fact, as described in Section VII.A.2 of the preamble, for this low utilization subcategory, EPA selected composite-lined surface impoundments in combination with a BMP plan as the BAT technology basis for BA transport water and established limitations on TSS. Under the CCR Part A rule, plants will have to close any unlined impoundments and use another technology to meet these limits (which could include retrofitting an impoundment or constructing a new one). In either case, no plants will be allowed to "continue using their unlined lagoons for bottom ash," as asserted by the same commenter. Furthermore, to the extent that a plant used composite-lined surface impoundments to meet the final limitations applicable to discharges from low utilization EGUs, the plant would also be required to implement a BMP plan to further recycle BA transport water and reduce the discharge of pollutants. See section VII.C.2 of the preamble for additional rationale regarding BA transport water for the low utilization subcategory.

NPDES Permits

EPA agrees with the commenter who stated that it might be necessary for impoundments at plants where the plant or some of the units have retired "to continue to operate to manage storm water and other non-coal combustion residuals contact water waste streams until such time that closure activities have been terminated." The ELGs do not require "termination of a facility's NPDES permit immediately after the unit ceases to generate electricity." In fact, any person who discharges or proposes to discharge pollutants must apply for an NPDES permit (or reapply before expiration of an existing permit), regardless of the status of their generating unit(s). *See* 40 C.F.R. 122.21(a) & (d).

11 FGD Wastewater – General

The final rule establishes Best Available Technology Economically Achievable (BAT) based on chemical precipitation with low residence time reduction (CP+LRTR) biological treatment for flue gas desulfurization (FGD) wastewater as detailed in Section VII.A.1 of the preamble (see Section VII.B.1 of the preamble for an explanation of the Environmental Protection Agency's (EPA's) rationale). This response expands on the rationale discussed in the preamble in order to address issues raised by public comments categorized as Code 11 (FGD Wastewater – General). See Part 1 of this document for a list of Code 11 excerpts. The response has been organized into subtopics; identified by subheadings below. This response covers the following subtopics.

- Requirements for Existing Sources (PSES)
- Flow Estimates
- Water Quality Monitors
- Cost Estimates and Cost-Effectiveness
- Limitations
- Inhibited Oxidation
- High Flow Subcategory Costs
- Zero Discharge Technologies

See responses to Code 43 (Numeric Limits) and the S*upplemental Statistical Support Document for Effluent Limitations for Steam Electric Power Generating Effluent Limitations Guidelines and Standards* (DCN SE09462)for details on the revisions to the set of sampling data used to establish effluent limitations for the final rule.

- See response to Code 5 (Regulatory Options – Compliance Cost Methodology) for more information on the BOOM approach and EPA's evaluation of leasing FGD wastewater treatment technologies.

Requirements for PSES

EPA disagrees with commenters requests for no PSES requirements in the final rule or for a delayed effective date for FGD PSES. See Section VII.E of the preamble for a further discussion on EPA's rationale for establishing PSES limitations. The Act requires compliance with pretreatment standards no later than three years after promulgation. See Section XIV.A.1 of the preamble for details on the timing for PSES requirements.

EPA is establishing PSES limitations based on CP+LRTR technology. See Section VII of the preamble for a description of the regulatory options evaluated for the final rule. While EPA acknowledges that City Water Light and Power (CWLP) Dallman may be the only plant currently discharging FGD wastewater to a publicly owned treatment works (POTW), this does not preclude existing plants from becoming indirect dischargers, and needing to have requirements under PSES, in the future.

While this rule does not revise the new source performance standards (NSPS) or pretreatment standards for new sources (PSNS) established in the 2015 rule, EPA disagrees with the commenter's statements suggesting that any facility becoming a new indirect discharger after November 3, 2015 would be subject to the PSNS rather than the PSES. For purposes of determining whether PSNS/NSPS or PSES/BAT limitations apply, the relevant question is whether the generating unit is a new *source* or existing *source*, not whether the plant discharges indirectly for the first time after a certain date. Any existing generating unit that chooses to indirectly discharge their FGD wastewater would be subject to PSES. As a result, the PSES requirements set equal to BAT limitations prevent existing power plants discharging FGD wastewater from circumventing more stringent requirements by simply relocating their wastewater discharge point from a surface water to a POTW.

EPA also disagrees that the final PSES incentivizes facilities to switch from being an indirect discharger to a direct discharger of FGD wastewater. In addition to the capital and O&M costs associated with implementing additional treatment to meet the BAT/PSES limitations, there are additional costs associated with direct discharge of FGD wastewater. First, the permit writer must establish more stringent limits where necessary to meet water quality standards of the receiving water (See CWA section 301(b)(1)(C)). Second, the costs associated with collecting information for and completing a National Pollutant Discharge Elimination System (NPDES) permit application and on-going monitoring of effluent and reporting to the NPDES program may exceed the costs associated with indirect discharge to the POTW. EPA expects that the prospect of additional responsibility and cost associated with becoming a direct discharger would not motivate plants to change their current POTW discharge.

One commenter stated that footnote 80 in the proposed rule preamble is inaccurate. In response to this comment EPA removed this statement in the final rule preamble.

One commenter asserted that their plant "as an indirect discharger subject to the pretreatment standards for existing sources (PSES), is disproportionately impacted by the ELG rule." EPA disagrees that their plant is disproportionately affected. The chemical precipitation pretreatment system cited at the commenter's plant should meet PSES limitations for arsenic and mercury, when well operated. Data provided by CWLP from 2014 and 2015 show some but not all results below the monthly limitations for mercury and arsenic (EPA-HQ-OW-2009-0819-8331-A2). However, as demonstrated by the average concentrations included in Table 6-1 in the Supplemental TDD, this system is unlikely to achieve the PSES limitations for nitrate/nitrite and selenium. EPA acknowledged this in its evaluation of the cost to meet the requirements of the final rule, and found the cost to install the LRTR system (or equivalent) to be economically achievable. Through EPA's subcategorization analysis, the Agency specifically examined the cost of the final PSES on the basis of capacity utilization, taking credit for the plants existing chemical precipitation system treatment in place, and determined that this plant is not disproportionately impacted (see "Steam Electric Effluent Guidelines Reconsideration – Evaluation of Final Rule Subcategories" memorandum (DCN SE09071)). Please note that EPA incorporated the commenter's information on the industrial user rates charged by the POTW that it discharges to and updated that cost savings reflected in the membrane filtration cost methodology (see "FGD Membrane Filtration with Encapsulation Cost Methodology" memorandum (DCN SE08625)). EPA also incorporated the commenter's information on the plant's receiving water for FGD wastewater discharge (see "Receiving Waters Characteristics Analysis and Supporting Documentation for the 2020 Steam Electric Supplemental Environmental Assessment" (DCN SE08753)).

The commenter asserts that SCWRD provides sufficient treatment, in combination with Dallman's system, to meet the BAT limitations set forth in this rule. Where certain POTWs may provide additional treatment of pollutants in steam electric power plant wastewater, dischargers can benefit by using the removal credit regulations, a regulatory mechanism by which industrial users can discharge a pollutant in quantities that exceed what would otherwise be allowed under an applicable categorical pretreatment standard because it has been determined that the POTW to which the industrial user discharges consistently treats the pollutant. See 40 Code of Federal Regulations (CFR) § 403.7.

As described in the Supplemental TDD, EPA's pass-through analysis relies on data from the 2015 rule (see Section 11 of the *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-15-007) (2015 TDD)). EPA continues to use these POTW removal percentages to characterize average treatment at POTWs (see *Fate of Priority Pollutants in Publicly Owned Treatment Works* (EPA-440-1-82-303) and the National Risk Management Research Laboratory (NRMRL) Treatability Database, Version 5.0 for the removal percentages EPA used in its pass-through analyses). EPA applies the same removals to all POTWs nationwide. As described in Section 11.2 of the 2015 TDD, pollutants are determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by the BAT technology basis. EPA determined that all four regulated pollutants for FGD wastewater passed through POTWs and required limitations under PSES.

EPA disagrees that it should decline to adopt a PSES for FGD wastewater because PSES is not necessary to achieve environmental benefit as applied to CWLP and its POTW. First, as described above, PSES applies to any existing facility that currently or in the future begins indirectly discharging FGD wastewater, not just to CWLP and its POTW. Second, Section 301 of the Act and its legislative history indicate that pretreatment is intended to be analogous to BAT as this means the indirect discharger, rather than the POTW or other treatment plant, pays to control discharges. *See also CMA v. EPA*, 870 F.2d 177, 244 (5th Cir. 1989) (rejecting a challenge to an effluent guidelines rule based on the argument that EPA must take into account the performance of actual POTWs) ("In 1977, when Congress amended the CWA to strengthen the provisions for controlling toxic pollutants, Congress provided that 'an indirect discharger . . . had to 'pretreat' its waste waters so as to achieve, together with the [POTW] that treated the waste before final discharge . . . the same level of toxics removal as was required of a direct discharger.") (citing *NRDC v. EPA*, 790 F.2d 289, 292 (3d Cir. 1986)). "Categorical pretreatment standards are technology-based and analogous to the BAT effluent-limitation guidelines for the removal of toxic pollutants – that is, they are intended to represent the best available technology that is economically achievable by indirect dischargers." *CMA v. EPA*, 870 F.2d at 243 (citing H.R. Rep. No. 830, U.S. Code Cong. & Admin. News 1977, reprinted in 1977 Leg Hist at 271, 342, 403)). Moreover, where certain POTWs may provide additional treatment of pollutants in steam electric power plant wastewater, dischargers can benefit by using the removal credit regulations, a regulatory mechanism by which industrial users can discharge a pollutant in quantities that exceed what would otherwise be allowed under an applicable categorical pretreatment standard because it has been determined that the POTW to which the industrial user discharges consistently treats the pollutant. See 40 CFR § 403.7. See response to a similar comment (EPA-HQ-OW-2009-0819-4379-A1, Excerpt Number 144) in EPA's response to public comments from the 2015 rule (see DCN EPA-HQ-OW-2009-0819-6469).

The comment mentions that the SCWRD's wastewater treatment capabilities include biological nutrient removal and other treatment in place that may remove pollutants to concentrations below the final rule's limitations. However, as described above, EPA is not obligated to evaluate PSES for FGD wastewater based on one POTW's performance. Table 1 lists the 2019 local arsenic, mercury, and selenium limits imposed on dischargers to SCWRD, provided by the commenter in Exhibit B (EPA-HQ-OW-2009-0819-8331-A3). These concentrations are higher for all pollutants than those specified by this final rule for PSES discharges. EPA notes that if in fact SCWRD has treatment that removes the final rule regulated pollutants, CWLP could work with EPA Region V and SCWRD to explore the potential of removal credits for these pollutants through categorical pretreatment standards. Removal credits are also mentioned in material provided by the commenter, see Section 7.1 of Exhibit B (EPA-HQ-OW-2009-0819-8331-A3).

Table 1. 2019 Pretreatment Ordinance Local Limits for SCWRD

Pollutant	Limit (mg/L)
Arsenic	0.4
Mercury	0.0005
Selenium	0.5
Nitrate/nitrite as N	No Limit

Source: EPA-HQ-OW-2009-0819-8331-A3

As described in Section VII.B.3, EPA did not finalize a voluntary incentives program (VIP) for PSES. The CWA states that PSES shall specify a time for compliance not to exceed three years from the date of promulgation (33 U.S.C. §1317(b)(1)). While this facility cannot take part in the VIP, Dallman is not precluded from installing an alternative treatment technology, and EPA notes that there is record information that Dallman has purchased a thermal wastewater treatment system (see Appendix A Section 2.3 of the "Technologies for the Treatment of FGD Wastewater" memorandum (DCN SE09213) for details on the thermal system) to meet the final PSES.

Flow Estimates

Public commenters asserted that EPA both underestimated and overestimated the FGD wastewater flows used to size treatment equipment and estimate compliance costs. EPA has made reasonable assumptions based on information provided by plants, industry trade associations, and information that is publicly available. Neither the costs, nor the pollutant loading estimates prepared by EPA, for the purpose of evaluating various regulatory options, are designed to reflect changes to an industry with exact precision. *See BP Exploration & Oil, Inc. v. EPA*¸66 F.3d 784, 800 (6th Cir. 1995) ("'The CWA does not require a precise calculation of BAT and NSPS costs.'") (quoting *NRDC, Inc. v. EPA,* 863 F.2d 1420, 1426 (9th Cir. 1988)); *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 237-38 (5th Cir. 1989) ("The Act requires the EPA to 'take into account' the costs of BAT; it does not require a precise calculation. The EPA 'need make only a reasonable cost estimate in setting BAT'; it is sufficient if the EPA develops 'a rough idea of the costs the industry would incur.'") (internal quotations and citations omitted); *see also Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 936 (5th Cir. 1998) (EPA's effluent reduction estimates were performed "only to satisfy the CWA's unrelated requirement that the EPA 'identify' in its regulations the degree of effluent reduction attainable through the application of BAT . . . As such, even serious flaws in the effluent reduction estimates could not provide grounds for remanding the zero discharge limit.") (citing 33 U.S.C. § 1314(b)(2)(A)). EPA's cost estimates provide a reasonable estimate of costs incurred to plants industry-wide. See Section 5 of the supplemental TDD for an explanation of EPA's cost methodology.

Several comments asserted that EPA should not have used optimized FGD purge flow rates in its cost estimates. However, EPA confirmed that flow optimization is a reasonable step plants can take to minimize compliance costs using data collected during site visits, meetings with industry representatives, and other sources. EPA is aware that at least two plants anticipate implementing flow optimization approaches as they upgrade their FGD wastewater treatment (see "Trimble County Generating Station Site Visit Notes" (DCN SE07143) and "Southern Plant Scherer Meeting Notes" (DCN SE08619)). As described in the Supplemental TDD, EPA estimates capital costs using average FGD flow rates that do not account for flow optimization. Thus, the size of the treatment system EPA is costing for some plants may reflect more capacity than is necessary and as a result overestimate costs. EPA estimated annual costs for operations and maintenance using the optimized flow (see the "FGD Flow Methodology" memorandum (DCN SE08630)) in an effort to reflect likely operating conditions. While the flow used for estimating capital costs may overestimate the size and cost of the treatment system, EPA chose to use this flow rate to ensure that installed treatment technologies would be able to accommodate the maximum possible FGD flow.

EPA disagrees with commenters who asserted that the Agency's approach of assuming facilities can reduce flow rates through optimization results in underestimating size and cost of treatment systems. As described previously in this response, EPA only used optimized flow to estimate O&M costs, not capital costs (including size of the treatment system). O&M costs include items related to annual operation and maintenance of the system, including treatment chemicals, energy requirements, and labor. As described in Section 5.2.1 of the Supplemental TDD, EPA estimated optimized flows based on chloride concentrations, including design chloride and operating chloride levels. EPA agrees with commenters that chloride concentration and materials of construction may not be the only basis plants use to determine the amount of recycle to implement. However, the comments do not demonstrate that EPA's estimates are unreasonable. Furthermore, the commenters did not provide specific data on the FGD systems at plants (such as fines concentration, gypsum quality, and oxidation reduction potential (ORP)) that could have allowed EPA to incorporate these other factors into its estimates of flow rates.

EPA also disagrees with commenters who suggested using peak flows as the basis for estimating costs. Using peak flows to estimate O&M costs would likely overestimate the annual costs incurred by plants. Instead, EPA used optimized flow rates to calculate a reasonable estimate of the O&M costs incurred by plants under the final rule. For capital costs, EPA used flow rates that have not been reduced to ensure that well-operated treatment systems would have enough capacity (including equalization) to handle peak flow events. Estimating capital costs based on peak flows would result in a system that is unnecessarily oversized. LRTR costs provided by the vendor include N+1 redundancy for capital costs associated with each unit process (DCN SE07120). Costs for other capital elements not included in the vendor cost estimate are calculated as factors (or additional percentages) added to vendor costs.

As described in the Supplemental TDD and various cost methodology memoranda, EPA developed cost methodologies that allow for transparency in both the flows used to estimate costs and the cost factors and equations used to estimate costs "FGD Flow Methodology" (DCN SE08630) and "FGD Cost Database" (DCN SE08628)). Where a commenter felt costs were not accurately estimated or flows were not reflective of the actual system operation, the opportunity to provide comment and correct EPA's estimates was available through the public comment process. For comments providing flow rates that differed from EPA's FGD purge flow rates, the Agency revised those flow rates as provided in comments. Plant-specific updates to flows based on public comments are listed in Table 2. For all plants listed in Table 2, EPA revised the FGD flow for purposes of estimating capital costs and continued to apply the optimized flow methodology described in "FGD Flow Methodology" (DCN SE08630) to estimate O&M costs. In response to comments, EPA also added Plant Scherer SE Unit-1 to the population serviced by FGD systems and discharging FGD wastewater (see "Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule" memorandum (DCN SE08688)).

Table 2. Plant-Level FGD Purge Flow Updates from Public Comments

Plant ID	Plant Name	Average Flow Rate (GPM)	FGD Purge Flow (GPD)
928	Plant E C Gaston	300	432,000
1493	Plant James H Miller Jr	300	432,000
2244	Plant Bowen	1,425	2,052,000
5043	Plant Wansley	600	864,000
7651	Plant Barry	200	288,000
8179	Plant Scherer	100	144,000

Source: EPA-HQ-OW-2009-0819-8457-A1

EPA disagrees that its methodology is based entirely on maximum FGD purge flow rates. As described in the "FGD Flow Methodology" (DCN SE08630), the primary source of data for plant-specific FGD flows is the 2010 *Questionnaire for the Steam Electric Power Generating*

Effluent Guidelines (Steam Electric Questionnaire) (EPA-HQ-OW-2009-0819-8115). EPA's methodology utilizes this robust data set to the extent possible with regard to reported purge flows and design capabilities of individual FGD scrubber systems. Lacking plant-specific details on where an individual plant could further reduce its flow or operate with an FGD purge smaller than what is included in EPA's estimate, the Agency continues to estimate flows using the data available in the record.

Commenters suggested several methods for flow reduction. While EPA recognizes that purge flow rates may vary depending on the type of coal burned, many plants may not have access to other coal sources; however, factors other than FGD purge are impacted by the type of coal burned and EPA is not requiring plants to alter fuel sources. In addition, one commenter suggested that most FGD wastewater treatment systems should be designed for sufficient equalization capacity to handle peak flows for short duration, assuming that most coal units do not operate as base load units. Data available through the Energy Information Administration (EIA) demonstrate that electricity generation can change year to year. As such, EPA's cost estimates size the system for an average flow because the extent to which FGD purge will vary is unknown.

EPA disagrees that all FGD flows are based on 2015 coal usage. To clarify EPA's flow methodology, the Agency uses flow rates reported through the 2010Steam Electric Questionnaire as the primary data source. Where data gaps exist, such as where a new FGD system was installed since the Steam Electric Questionnaire and EPA could not obtain the flow rate from a National Pollutant Discharge Elimination System (NPDES) permit, the Agency uses EIA data to estimate flows. To address data gaps for the final rule analysis, EPA used 2018 EIA coal usage and applied a relationship based on the median FGD flow per ton of coal burned (see Section 5 of the Supplemental TDD).

EPA's cost estimates reflect costs for plants to upgrade current treatment in place to the BAT technology basis. The specific technology costs vary based on which regulatory option is being evaluated, see the preamble for a discussion of the various regulatory options. As described in the "FGD Wastewater Treatment in Place at Steam Electric Power Plants" memorandum (DCN SE08629), EPA has compiled a list of FGD wastewater treatment systems installed at each plant discharging FGD wastewater. This listing is updated as new treatment systems are installed. EPA does not have data on what types of technology individual plants may be working to design or in the planning stages of developing. As such, the cost estimates do not account for costs associated with any redesign. The amount of incremental costs EPA estimated varies by technology. As described in Section 5 of the Supplemental TDD, EPA assessed partial costs based on the upgrades needed for each technology option evaluated as part of the final rule.

EPA disagrees that the proposed text at 40 CFR 423.13(g)(3) requires updating. EPA is finalizing the definition of high FGD flow as proposed, based on EPA's subcategorization analyses supporting high flow plants. See responses to Code 9c (Subcategorization – High FGD Wastewater Flow) for additional discussion of EPA's subcategorization for high flow plants.

Water Quality Monitors

EPA agrees with commenters who stated that water quality monitors for real-time measurements of selenium and mercury are not yet proven for FGD wastewater. As such, EPA has not included such real-time monitors as part of the technology basis of the final rule. These monitors are not required for system operation, nor were they used to collect the measurements with which the effluent limitations are based. EPA welcomes future research on available technology and field-testing potential solutions to making further forward progress with the technology, but these monitors are not a requirement for compliance with the final rule. EPA did include costs for a mercury analyzer that can be used to optimize operation of the CP system even though it analyzes samples and cannot operate in real time. See response to Code 35 (Regulatory Implementation – Compliance Monitoring) for additional discussion on water quality monitors.

Cost Estimates and Cost-Effectiveness

The CWA does not require EPA to evaluate toxic-weighted pounds equivalent (TWPE) in order to establish BAT/PSES. See response to Code 5 (Regulatory Options - Compliance Costs Methodology). EPA disagrees that "toxicity" is a better measurement of pollutant reductions than pollutants loadings expressed in pounds per year. EPA instead used the sum of total suspended solids (TSS) and total dissolved solids (TDS) to better represent the quantity of pollutants present in FGD wastewater. This method prevents double counting of pollutants for which EPA has concentration data while also accounting for pollutants that do not have a toxic weighting factor (TWF), such as nitrate. Refer to the "Analyte Level Loadings and Removals for Each Wastestream and Regulatory Option" memorandum (DCN SE08644) for estimates of individual constituents for each regulatory option. Cost-effectiveness is calculated and is presented as part of the *Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA) (EPA-821-R-20-004); however, this cost-effectiveness analysis was not used as a decision factor for the final rule.

EPA reviewed the commenter's methodology for calculating pollutant reductions using TWPE. EPA disagrees with how J-values were handled (using J-flagged analytical data at the reported concentration). As described in Section 10.2.2 of the 2015 TDD, for calculating FGD wastewater loadings, EPA uses half the quantitation limit to estimate concentrations flagged as J-values because J-values are measurements made below the lowest point on the initial calibration curve and have greater uncertainty associated with their quantitation. In addition, EPA disagrees with the commenter evaluating chemical precipitation separately from biological treatment and from membrane filtration. The BAT technology basis for the final rule is CP+LRTR, and the VIP technology basis is membrane filtration with chemical precipitation pretreatment. EPA's loadings analyses evaluate each of these combined systems because it is the combination of the systems that results in the established effluent limitations. The treatment being characterized by the commenters as associated with the biological treatment portion of the system may not be the same if the system was preceded with treatment other than chemical precipitation. As such, EPA disagrees with the commenter's suggestion that treatment capability be characterized as two distinct pieces rather than one combined system. Finally, because EPA did not gather new data on pollutant concentrations for all pollutants included in its loadings analyses for the CP+LRTR technology, concentration values presented in the Supplemental TDD remain unchanged from proposal.

EPA disagrees with this commenter's approach of calculating pollutant removals differentiated by coal type and does not believe such analysis is warranted or necessary. This topic was addressed in EPA's response to comments in the 2015 rule (DCN EPA-HQ-OW-2009-0819-6469), specifically see EPA-HQ-OW-2009-0819-4655 Excerpt Number 107 in comment Code 10.a (FGD Bio – Demonstration/Performance). For the pollutants regulated by the final rule's BAT of CP+LRTR (which remain the same in this final rule as they were in the 2015 rule for the CP+HRTR technology basis), concentrations can range in FGD wastewater from plants burning subbituminous coal (or lignite), but the type of coal burned is not the sole determining factor of the concentrations found in FGD wastewater. Air emissions from the combustion of coal contain byproducts of combustion (e.g., SO_2, NOx, particulate, and trace quantities of other pollutants), and these byproducts can then be transferred to FGD wastewater when flue gas is wet scrubbed. While the coal is the source of pollution in FGD wastewater, trace elements of interest, such as selenium, mercury, arsenic, and nitrogen, as well as sulfate, are found at a range of concentrations in all types of coal. Therefore, the specific coal type, or rank, does not definitively specify the concentration of these and other elements present in the coal, nor in resulting FGD wastewater. In addition, this range of constituents present does not limit the effectiveness of the BAT treatment system. The commenter has not provided data to demonstrate the limitations cannot be achieved at all plants or at plants that burn a specific type of coal. Chemical precipitation systems have demonstrated the ability to handle the FGD wastewater variability prior to biological treatment.

Commenters have also suggested that bromide concentrations in coal may vary and impact a plant's ability to meet a potential limitation on bromide discharges. EPA agrees that naturally-occurring bromide concentrations may vary and recognizes that some plants apply halogen or halogenated compounds that may contain bromide to coal in order to meet the requirements of the Mercury and Air Toxics Standards (MATS). See Section 6 of the Supplemental TDD for details on how EPA accounts for both of these components in its estimates of bromide loadings. Other than plants that will opt into the VIP, EPA has elected not to set a bromide limitation for BAT. As described in Section XIV.C of the preamble, the EPA agrees with the wide variety of commenters that the selection of BAT based on the statutory factors, combined with the imposition of water quality-based effluent limitations on a permit by permit basis, where necessary, is the proper way to address impacts from bromides at this time.

EPA disagrees with commenters who asserted that costs per toxic-weighted pound equivalent (TWPE) is "the more appropriate basis with which to calculate treatment cost-effectiveness" and that EPA should incorporate this factor into its economic achievability determination. As discussed previously in this response, cost-effectiveness is estimated and presented in the RIA but not used as the basis for selecting BAT or PSES requirements for the final rule. See section VII.E of the preamble for a discussion of the rationale for setting PSES. See response to Code 5

(Regulatory Options – Compliance Costs Methodology) for more discussion of cost-effectiveness.

One commenter used cost factors in its own cost estimates that differ from those used in EPA's methodology. EPA disagrees with the commenter's assertion that the cost factors the Agency used to supplement vendor-provided costs resulted in underestimated industry-level compliance costs. The commenter did not provide data to demonstrate that cost factors used by EPA were not typical of industry standard engineering estimates or that they are otherwise unreasonable. See also response to comment Code 15 (FGD Wastewater – CP+LRTR).

EPA reviewed the commenter's methodology for estimating FGD wastewater treatment followed by brine solidification, specifically the commenter provided cost estimates for a model plant using the following treatment technologies:

- Chemical precipitation followed by evaporation and brine solidification.
- Chemical softening followed by seawater reverse osmosis and brine solidification.
- Chemical precipitation followed by membrane filtration and brine solidification.

EPA includes solidification, also referred to as encapsulation, as a method of disposal following both membrane filtration and some thermal evaporation technologies in its analysis. See the response to comment Code 17 (FGD Wastewater – Membrane Filtration) for EPA's responses specific to membrane filtration. For the final rule, EPA estimated costs associated with thermal evaporation. See the "FGD Thermal Evaporation Cost Methodology" memorandum (DCN SE08631) for a description of the costs estimated for thermal evaporation. EPA aggregated cost data for the following treatment technologies: brine concentrator with encapsulation, crystallization, direct contact evaporation system, and spray dryer evaporator in order to protect vendor-specific claims of confidential business information. As described in the memorandum, EPA estimates costs for thermal evaporation using cost factors and assumptions similar to both CP+LRTR and membrane filtration cost methodologies. EPA See response to comment code 15 (FGD Wastewater – CP+LRTR) and code 17 (FGD Wastewater – Membrane Filtration) regarding details on the cost factors, assumptions about fly ash available for encapsulation, and transportation and disposal.

Similar to this commenter's methodology, EPA estimated costs for a non-pumpable mixture following brine encapsulation that would be hauled to a landfill. EPA's cost methodology includes costs associated with landfill expansion needed to dispose of the additional brine solids. This element appears to not be included in the commenter's methodology. In EPA's analysis, brine from the membrane will be encapsulated by mixing with fly ash and lime. EPA acknowledges that plants may divert fly ash for beneficial reuse, however, EPA has evaluated EIA data for fly ash sales, and, based on that data, the commenter's assumption that 60 percent of a plant's fly ash generation is sold is an overestimate. The commenter's value is being sold or reused at an average plant industry-wide. See the "Final Revisions to the Steam Electric ELGs: Fly Ash Availability" memorandum (DCN SE09070) for information on EPA's evaluation of fly ash disposition required for brine encapsulation. EPA expects that plants could conduct bench-scale testing to optimize brine management. EPA includes costs associated with planning and engineering the system and contingency costs, which when considered in aggregate as a reasonable estimate of the costs borne by the industry are sufficient to account for case-by-case pilot testing for the plants where it may be necessary.

EPA agrees that costs for encapsulation of FGD wastewater may vary; however, the commenter has not provided data to demonstrate that EPA's overall industry estimates are unreasonable. See responses to Code 17 (FGD Wastewater – Membrane Filtration) for a discussion of membrane filtration costs and details related to encapsulation. EPA has reasonably estimated costs for BAT as described in the caselaw. *See, e.g., Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 237-38 (5th Cir. 1989) (The Act requires the EPA to "take into account" the costs of BAT; it does not require a precise calculation. The EPA "need make only a reasonable cost estimate in setting BAT"; it is sufficient if the EPA develops "'a rough idea of the costs the industry would incur'" (citation omitted).

Another commenter included a case study cost estimate for "Chemical softening (CS) followed by seawater reverse osmosis and brine solidification" in its comments. EPA did not evaluate seawater reverse osmosis as a potential FGD wastewater treatment technology basis and thus cannot provide a direct comparison to the commenter's case study evaluation. In addition, the final rule does not establish any effluent limitations or guidelines based on this technology as EPA did not have sufficient data in its record to evaluate its performance.

Some commenters suggested that, in estimating compliance costs, EPA take into account site-specific factors other than flow rate and capacity. EPA did review EPA-HQ-OW-2009-0819-7310.35 for available cost information submitted by one commenter; however, none of the treatment trains are equivalent to the technology bases for which EPA estimated costs for in support of the final rule (i.e. do not include all of the same components). In addition, these commenters have not provided data to demonstrate that EPA's methodology yields unreasonable estimates. EPA disagrees that it should include additional factors in its cost estimates. EPA's methodology estimates treatment costs for each plant discharging FGD wastewater using plant-specific flows and general relationships between capital or O&M costs and wastewater flow and is intended to provide reasonable industry-wide cost estimates. As described in the Supplemental TDD, these costs include aspects of direct and indirect capital components. Specific estimates for individual plants may be over or underestimates, but EPA maintains that estimates at the industry level are a reasonable estimate of what it would cost the steam electric power generating industry to meet the requirements of the final rule. While commenters have cited plant-specific cost estimates or plant-specific details, without these same details for all plants discharging FGD wastewater, it is difficult to determine how these same factors would be incorporated into estimates for other plants in the industry. The commenter cites a methodology developed by EPRI, who uses a similar industry-wide cost curve approach, and mentions specific cost factors to reflect available space and commingled systems. As discussed in the 2015 rule, based on data from the Steam Electric Questionnaire, EPA determined that plants had sufficient space to install the CP+HRTR treatment systems, and subsequently, the Agency did not account for an additional cost. As mentioned previously in this response, EPA's costs do include a contingency cost that the Agency expects would be used for these plant-specific considerations resulting in increased costs. EPA includes a factor of 10 percent of direct and indirect capital costs (or 38 percent of equipment costs) as referenced in the Peters and Timmerhaus' *Plant Design and Economics for Chemical Engineers* if a contingency cost was not already included in the vendor estimate. See responses to comment Code 15 (FGD Wastewater – CP+LRTR) and Code 17 (FGD Wastewater – Membrane Filtration) for a further discussion on EPA's cost methodologies for technologies evaluated as part of this final rule.

Limitations

Some commenters asserted that by using pilot study data in establishing limitations for FGD wastewater, EPA's estimates neglected to account for variability. EPA disagrees. The set of data EPA used to establish limitations for BAT includes data from six pilots of the CP+LRTR technology. As described in Section 8 of the Supplemental TDD, the calculation of limitations does account for variability within each set of data used to establish limitations. As discussed in Section 8.2.6 of the Supplemental TDD, "Variability factors provide an additional assurance that normal fluctuations in a plant's treatment process are appropriately accounted for in the limitations. By accounting for these reasonable excursions above the long-term average, EPA's use of variability factors results in effluent limitations that are above the long-term averages." Commenters do not provide details to support claims that EPA's analysis did not reflect the variety of unit operations. See section X of the preamble and response to comment Code 43 (Numeric Limits) and Code 15 (FGD Wastewater – CP+LRTR) for further discussion on EPA's use of pilot study data in developing limitations for the final rule and estimated costs for the final rule.

Inhibited Oxidation

A commenter asserted that it "is not clear that the Agency can rationally assume, as it eventually did in the 2015 TDD, that purge water from inhibited oxidation is identical to that from forced oxidation. It cannot therefore assume that chemical precipitation and biological treatment for purges from inhibited oxidation will accrue the same benefits. Given the large costs of compliance, any corresponding benefits are presumptively inadequate." The final rule does not establish a subcategory with different standards for inhibited oxidation FGD systems. Therefore, EPA disagrees with the commenter's assertion that "any corresponding benefits are presumptively inadequate." EPA has no new information on inhibited oxidation, or so-called "high recycle rate" FGD systems since the 2015 rule. Information on FGD systems was originally collected from the 2010 Steam Electric Questionnaire. Updates to plant-specific FGD wastewater flows and the population of plants generating FGD wastewater are described in the "FGD Flow Methodology" memorandum (DCN SE08630). However, no additional information on inhibited oxidation systems has been obtained since 2010. See EPA's response to DCN EPA-HQ-OW-2009-0819-4448-A1 Comment Excerpt Number 24 in comment Code 9.a (FGD CP – Demonstration/Performance) for the Agency's discussion of inhibited oxidation systems and their ability to meet the 2015 effluent limitations. Commenters provided no data to supplement data from the Steam Electric Questionnaire on the characterization of FGD wastewater from inhibited oxidation systems, nor have commenters provided data to demonstrate that the wastewater generated by these systems cannot be treated by the BAT technology in the final rule. Consistent with its analysis for the 2015 rule and the 2019 proposal, EPA again determined for the final rule that subcategorization for inhibited oxidation system is not warranted. Commenters have not provided any data to demonstrate that the constituents and concentrations within FGD wastewater generated by inhibited oxidation systems are substantially different from those constituents and concentrations in FGD wastewater generated by forced oxidation systems such that the treatment technologies would perform differently.

In 2010, based on data collected as part of the Steam Electric Questionnaire, there were approximately 20 plants that operated inhibited oxidation systems, roughly 75 percent of which do not discharge FGD wastewater. For the final 2020 rule, EPA identified only two plants that operate inhibited oxidation systems and discharge FGD wastewater with requirements under the final rule. Of these two plants, one treats FGD wastewater with evaporation and one treats FGD wastewater with an existing chemical precipitation system. Both systems demonstrate that the FGD wastewater can be treated with technologies similar to those used to treat FGD wastewater generated by other types of scrubbers. For these two plants, EPA estimates the costs necessary to meet the requirements of the final rule as described in the Supplemental TDD. Dolet Hills, the specific plant referenced in comments, is not included in EPA's population of plants discharging FGD wastewater (see "FGD Flow Methodology" memorandum (DCN SE08630)). Based on data reported in the Steam Electric Questionnaire, all FGD wastewater generated by this plant is reused. EPA expects that because the plant is able to operate without an FGD wastewater discharge that it would continue to do so. In addition to not discharging FGD wastewater, Dolet Hills has announced plans to retire as of 2026 (DCN SE08719) and is thus eligible to be subcategorized for the final rule. EPA estimates that Dolet Hills will incur no costs under the final rule as they are expected to fulfill the requirements for the ceasing coal combustion by 2028 subcategory (see section VII.C of the preamble).

High Flow Subcategory Costs

Some commenters asserted that EPA over estimated compliance costs for plants in the high flow subcategory. EPA disagrees and, consistent with proposal, established in the final rule a subcategory for plants with high FGD purge flows due to disproportionate costs. See Section VII.C.1 of the preamble for more information on EPA's determination of this subcategory. EPA's cost estimates are based on FGD wastewater flow rate as described in the "FGD Flow Methodology" memorandum (DCN SE08630), rather than capacity or annual electricity generation. EPA uses both capacity and 2017 and 2018 generation data from EIA to assess capacity utilization in determining which generating units meet other subcategory thresholds. In response to commenters' assertions that flows should be adjusted based on current generation, EPA notes that electricity generation may change year-to-year, and for some generating units, this has changed from the generation reported in the 2010 Steam Electric Questionnaire, which is the basis for the majority of FGD wastewater flows; however, there are no consistent trends in electricity generation for the industry. As such, EPA has not adjusted flows based on trends in electricity generation. Lacking specific information on the current FGD wastewater flow rate at Cumberland or other steam electric plants, EPA continues to estimate FGD wastewater flow using the methodology described in the Supplemental TDD. Where individual plants reported different flows than those used to estimate costs, EPA updated those values, as previously discussed in this response essay.

EPA disagrees with commenters' suggestions regarding a requirement for plants to change coals in order to reduce FGD wastewater flows. Commenters suggested that plants in the high flow subcategory change coal type in order to reduce FGD purge and compliance costs. EPA cannot require plants to change fuel sources under the CWA. Plants can choose to change fuel sources as part of a compliance strategy for the requirements codified in the CFR, but such changes cannot be required. See response to Code 9 (Subcategorization) for more information on the high FGD wastewater flow subcategory.

Zero Discharge Technologies

Some commenters asserted that BAT for FGD wastewater should be based on zero discharge technology. As described throughout the proposed rule preamble and the final rule preamble, EPA disagrees and has declined to establish BAT for FGD wastewater as zero discharge. See Section VII.B.1 of the preamble for EPA's rationale regarding not selecting zero discharge for FGD wastewater. Also see response to comment Code 17 (FGD Wastewater – Membrane Filtration) for additional discussion on membrane filtration technologies.

12 <u>FGD Wastewater – Data</u>

No comment excerpts were received on this topic.

13 <u>FGD Wastewater – Halogens</u>

Some commenters asserted that "[w]et FGD discharges can contribute . . . to bromide concentrations in downstream drinking water sources" and "this issue is not isolated to a single geographic location." One commenter also asserted that "a lack of adequate effluent monitoring data makes it challenging to assess potential impacts of these bromide discharges on downstream drinking water sources." EPA does not disagree with these comments; however, as discussed in section XIV(C) of the final rule preamble, EPA's rulemaking record demonstrates that estimated changes in downstream bromide concentrations associated with changes in bromide discharges show that these impacts are concentrated at a small number of sites. This supports EPA's determination that potential discharges are best addressed using site-specific, water quality-based effluent limitations established by NPDES permitting authorities for the small number of steam electric power plants that may impact downstream drinking water treatment plants. See Section XIV(C) of the preamble to the final rule for discussion of EPA's reasoning. See also the response to Comment Code 36 (Regulatory Implementation – Halogens).

Use of Mass-Balance Approach to Estimate Bromide Loadings

One commenter stated that "[t]he best way to assess bromide loads from power plants remains the use of flow-weighted bromide concentration measurements for the flue gas desulfurization wastewater prior to mixing with other waste streams." EPA does not disagree with this comment; however, unlike other FGD pollutants, the impact of the type of coal in combination with the type of pollution controls have on the bromide level discharged is significantly more pronounced. To calculate loadings more specific to individual steam electric power plant operations, EPA performed a mass balance assessment of bromide loadings for the proposed rule. Another commenter stated that "[a]ny assessment of a potential regulatory approach to iodine must take into account the small quantities typically used by power plants for mercury reduction purposes as compared to naturally occurring iodine and non-coal sources of iodine" and that available information on iodine is limited. For the final rule, in response to comments, EPA revised the bromide loadings assessment methodology and also developed an iodine loadings assessment methodology using the more limited data available for iodine. EPA used the mass balance approach outlined in peer-reviewed, published studies (see the memoranda *Mass-Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants* (DCN SE07260; DCN SE08957) and *Mass-Balance Approach to Estimate Iodine Loadings from FGD Wastewater* (DCN SE08960) and Section 6 of the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001) (Supplemental TDD)).

The peer-reviewed studies used, in part, to develop the Agency's mass-balance approach to estimate bromide and iodine loadings in FGD wastewater discharges (DCNs SE06685 and SE07263) provide a reasonable estimate of national-scale bromide loadings from FGD wastewater.

Revisions to the Mass-Balance Approach

In response to comments suggesting the studies EPA relied on to conduct its mass-balance analysis were inaccurate, EPA reassessed the studies' underlying data and methodology. EPA determined that a mass-balance approach provided a valid methodology to estimate halogen (bromine and iodine) loadings from FGD wastewater discharges which would also account for variability among plants, as described above. See the memoranda *Mass-Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants* (DCN SE07260) for a discussion of how EPA's methodology differed from the methodology used in the 2016/2017 studies.

For the final rule, EPA further revised the mass-balance approach methodology based on feedback received in public comments. EPA adopted some commenter recommendations to revise the mass-balance approach to estimate bromide loadings in FGD wastewater. The Agency made the following revisions to its mass-balance approach:

- Revised the equation to convert wet coal consumption to dry coal consumption to as follows:

$$C_{dry} = C_{wet} \text{ X } (1 - \text{moisture content})$$

Where: Cdry = Coal Consumption, dry (tons/yr)

Cwet = Coal Consumption, wet (tons/yr)

Thus, EPA agrees, in part, with the commenter who asserted that the "bromide mass loading and transport model appears to have overestimated the amount of bromide reaching downstream drinking water treatment systems from current coal-fired power plant discharges." See also the response to Comment Code 41 (Benefits) regarding the transport model and downstream drinking water treatment systems.

- Converted wet coal consumption to dry coal consumption on a generating unit- and coal rank-specific basis, rather than only a generating-unit-specific basis, to account for differences in the coal types fired between units at the same plant.
- Calculated the weighted coal bromide (native concentration) for plants that burned multiple coals using dry coal tonnage rather than wet coal tonnage (see the MS Excel file *County-Specific Average Br Calculations* (DCN SE08906)).
- Determined the moisture content and bromine content on a plant- *and* coal-rank-specific basis to account for differences in the coal types fired between units at the same plant and kept the values separate rather than estimating weighted plant averages for use in the loadings calculations.
- Applied bromine content in coal and equivalent bromine in coal on a generating unit- and coal-rank specific basis, rather than only a generating-unit basis (with weighted plant averages).

One commenter noted that there can be differences in the coal types fired between units at the same plant and recommended that EPA revise its loadings methodology to account for variation in coal types between units. EPA agrees and revised its methodology. See the MS Excel file *County-Specific Average Moisture Calculations* (DCN SE08907) for further details.

The commenter also noted that some units within a plant were excluded from the analysis and that the plant-wide moisture did not yield an accurate estimation of the dry coal consumption for the plant. EPA used unit-specific data, where available, in its analysis; however, EPA did not have the data needed to develop unit-specific moisture content. In its analysis, EPA used coal purchases reported to EIA to identify the counties where the plant purchases coal and used USGS coal sampling data (by county) to determine the moisture content in the coal by coal type. The purchasing data are not reported on a generating unit-specific basis, and the commenter did not provide an alternative data source for unit-specific moisture content. Therefore, EPA calculated the moisture content in coal on a plant-specific and coal type-specific basis. The Agency disagrees with the commenter's assertion that using the plant-wide moisture does not yield an accurate estimation of the dry coal consumption for the bromide loadings analysis. EPA did not have the data to determine the county of origin for the coal purchased and burned at specific generating units. Therefore, EPA reasonably assumed that the moisture content by coal type burned at the plant is the same for all generating units, regardless of whether the unit is included in the halogen loadings analysis. See the MS Excel file *County-Specific Average Moisture Calculations* (DCN SE08907) for further details.

One commenter asserted that EPA "did not provide the information needed to accurately quantify" the loadings "associated with incorrect weighting of the coal moisture" or "bromide content calculated from the wet tonnage of each coal type" (see DCNs SE07260 and SE07267 for discussion of this approach presented at proposal). EPA disagrees because as discussed above for the first item, EPA cannot provide information that is not available, and because, for the second item, all necessary input data and calculation spreadsheets are included in the public docket.

Input Data for Mass-Balance Approach

Coal data. One commenter noted that the mass-balance approach presented in the peer-reviewed studies relies on historic coal consumption and coal quality data and may not represent current or future conditions. EPA's approach for the final rule used 2018 data reported by the industry to the Energy Information Administration (EIA) to determine coal consumption on a generating unit basis, which does reflect current conditions to the greatest extent possible given the available data. Regarding the use of older coal quality data, specifically the USGS COALQUAL version 3.0 data (DCNs SE07259A1, SE07259A2, and SE07259A3), the commenter did not provide details on why the use of the USGS coal quality data may not reflect current conditions and did not provide an alternative source of coal quality property data (i.e., moisture content and native bromine content). EPA's approach used COALQUAL data for the final rule analysis.

EPA acknowledges that future conditions may change as coal purchases (e.g., coal type), coal consumption rates, and halogen sources at steam electric power plants (i.e., use of refined coal and application of halogen compounds to control mercury emissions) may vary from one year to another. The Agency's analysis provides a reasonable estimate of current conditions, including coal consumption and halogen use, on an industry-wide basis using the most recently available generating-unit-specific data reported by the industry.

Bromide Addition at the Boiler. One commenter asserted that EPA "overestimated pre-combustion and post-combustion bromide addition" by using data reported in EPRI (2015) (DCN SE06958) that included generating-unit-specific values to represent equivalent bromine in coal (parts per million (ppm), dry) for generating units operating with boiler bromide addition systems. In response, for the final rule analysis, EPA reviewed and incorporated into the analysis more recent reports written by Electric Power Research Institute (EPRI) (DCNs SE08925 and SE08926). EPA calculated revised bromide loadings in FGD wastewater for the final rule based on the most recent EPRI report that provides generating-unit-specific data documented (see EPRI (2016) (DCN SE08925)). EPA acknowledges commenter's statement that the "median addition rates reported in the 2017 [EPRI] survey [and submitted with comments] were significantly lower than the values reported by EPA" in the proposal; however, the commenter did not provide adequate documentation of the data to allow EPA to duplicate the commenter's analysis nor incorporate the information into EPA's loadings analysis. In addition, EPA disagrees with the reasoning provided by the commenter for excluding data points documented in the reports from the bromide loadings analysis:

- The commenter's analysis is based on data from 35 generating units rather than the 89 generating units documented in the 2016 report (DCN SE08925).The reports cited by the commenter did not have sufficient data to determine which data points were excluded from its analysis and why. Therefore, EPA could not duplicate the analysis to confirm the stated results and explain it transparently.
- The commenter's analysis found that some "power companies participating in the [EPRI] surveys concluded that high bromide addition rates were problematic due to air heater corrosion, as well as unnecessary to meet the flue gas mercury emission standard … [and] obtained Section 45 certifications with lower amounts of bromide added to the coal in subsequent years." The commenter does not provide specific data on the reduction of bromide addition rates at some power companies (e.g., how much they are reduced) nor does it note whether any power companies increased bromide addition rates during the same time period. The data provided in the surveys still represent generating-unit-specific operations at the time of the survey (2016). In addition, the EPRI (2016) report likely incorporates, at least in part, bromide addition reductions that have occurred since the initial survey (2014). In addition, EPRI only had responses from power companies operating 63 of the 108 generating units in its 2017 survey on whether bromide addition rates decreased and just over half of those (35 units) decreased the bromide addition rate.
- The commenter limited its calculation of median equivalent bromine in coal for bromide addition to a subset of generating units, excluding those that were no longer operating as of December 31, 2018 and those that ceased bromide addition between 2014 and 2017. Given that the commenter did not provide information on why the omitted data were not reflective of industry-wide bromide addition practices, EPA disagrees with limiting the data set for an analysis of bromide addition rates. Regardless of the operation status of a generating unit included in EPRI's survey and documented in EPRI (2016) (DCN SE08925), the bromide addition rates still represent the most recently available generating-unit-specific bromide addition rates. In addition, steam electric power plants may alter their halogen use from one year to another; ceasing halogen addition at one point in time does not mean the plant will not resume halogen addition in the future and vice versa. Also, as noted above, EPRI (2016) likely incorporates, at least in part, the reduction in bromide addition by steam electric power plants since 2014.

Brominated Activated Carbon (Br-AC). One commenter stated that "where Br-PAC is injected downstream of an air heater [generating units] are likely to see less volatilization than EGUs [electric generating units] where Br-PAC is injected upstream of an air heater." EPA reviewed the data provided in the reference (DCN SE06951) and subsequent EPRI reports and revised its methodology to incorporate results that showed "bromide volatilization at a temperature of 300°F (typical of downstream air heater temperature) was half the value measured at 700°F (typical temperature just upstream of the heater).” See the MS Excel file *Bromine Equivalents in Coal for Br-AC* (DCN SE08913).

Other Comments

EPA disagrees, in part, with the commenter who asserted that the “journal articles … [that] describe the threat of bromides from power plants contain significant errors. Due to recent retirements of coal-fired power plants, changes in industry practices, the use of conservative estimates in the articles’ calculations, and an explicit error in an equation that likely permeates throughout the research, the articles overestimate the quantity and potential impact of bromide discharges.” One commenter noted that the “Fort Martin and Harrison facilities were improperly represented in the analysis” as documented in Good and VanBriesen (2016 and 2017)[52] (DCNs SE06685 and SE07263). EPA agrees, in part, that these articles and other literature sources (e.g., Cornwell, 2018 (DCN SE07937)) did not use plant-specific data as part of their analysis (e.g., current operations at plants); however, Good and VanBriesen (2016) (DCN SE06685) clearly specify that bromide loadings estimations include potential future uses of bromide additives at steam electric power plants and do not necessarily represent the current plant-specific operations. EPA disagrees with one commenter’s suggestion that the literature sources are not useful to inform EPA’s review of the methods to estimate halogen discharge loadings from steam electric power plants. EPA’s bromide loading analysis includes one of the plants cited by the commenter (Fort Martin) and uses plant-specific data gathered in support of this rulemaking to estimate plant-specific halogen loadings rather than assumptions from Good and VanBriesen; as such, EPA classified this plant as not adding halogens for enhanced mercury removal (see MS Excel file *Halogen Use Determination* (DCN SE08910)).

EPA disagrees with one commenter who asserted that literature sources such as the Good and VanBriesen articles should not be used to supplement the docket’s supporting information on bromide discharges and trihalomethane formation at drinking water treatment plants. Good and VanBriesen (2016 and 2017) (DCNs SE06685 and SE07263) did not have operation-specific data on the Fort Martin and Harrison plants and instead used best professional judgment and available data sources. The peer-reviewed studies clearly documented the analysis, the assumptions, and what the results represented. Comments regarding the equation to convert wet coal consumption to dry coal consumption are addressed above, and EPA conducted its own bromide loadings calculations to support the final rule.

Commenters noted that Cornwell (2018) (DCN SE07937) modeled bromide concentrations in the Ohio River that were higher than concentrations measured at a nearby monitoring station. Cornwell explicitly states that bromine inputs (e.g., native content in coal and bromide added to coal) were selected to represent a worst-case scenario. EPA disagrees with one commenter who

[52] Good, K.D. and J.M. VanBriesen. 2016. Current and potential future bromide loads from coal-fired power plants in the Allegheny River Basin and their effects on downstream concentrations. *Environmental Science & Technology* 50:9078-9088. DCN SE06685; Good, K.D. and J.M. VanBriesen. 2017. Power plant bromide discharges and downstream drinking water systems in Pennsylvania. *Environmental Science & Technology* 51:11829-11838. DCN SE07263.

asserted that "the use of conservative estimates" should preclude the Agency from using this peer-reviewed article to supplement the docket's supporting information on bromide discharges and trihalomethane formation at drinking water treatment plants. EPA conducted its own bromide loadings calculations to support the final rule using available data to estimate likely operating conditions rather than the worst-case estimates in the article that is of concern to the commenter.

Comments regarding the validation of results from modeling conducted by entities other than EPA using differing data inputs and assumptions and published in the literature are outside the scope of EPA's bromide loadings analysis for the final rule. As noted earlier, EPA used the framework of the mass-balance approach documented in Good and VanBriesen (2016 and 2017) (DCNs SE06685 and SE07263) to inform the development of its own analysis and calculation of halogen (bromide and iodine) loadings, and has incorporated changes to the methodology as recommended by commenters.

Regarding comments on the number of coal-fired power plants that have the potential to discharge to waters used by drinking water treatment plants, EPA incorporated known retirements and fuel conversions into its final rule analyses (see Sections 5 and 6 of the preamble to the final rule). EPA estimated bromide and iodine loadings for the final rule for the steam electric power plants that generate and discharge FGD wastewater (see DCN SE08688). EPA estimated halogen loadings for 61 plants, including five plants expected to retire or undergo fuel conversion before December 31, 2028. EPA did not analyze the same population of 407 plants noted in one public comment . EPA included 147 generating units in its halogen loadings analysis, including 5 units that are indirect dischargers. The commenter did not provide a list or citation for EPA to confirm their assertion that "only 87 electric generating units with at least one operable wet FGD system discharging to surface water." The commenter disagreed with the Good and VanBriesen (2019) (DCN SE08117) article that included 116 coal-fired power plants. However, EPA notes that Good and VanBriesen used publicly available data, including EPA data, to identify plants operating FGD scrubbers. Industry data is often proprietary and best professional judgment is used when evaluating incomplete data sets. In addition, EPA disagrees with the commenter's concern that data collected or modeled based on plants no longer in operation (as included in the Cornwell analysis) is not relevant or valid. These data are still useful for informing EPA's review of how steam electric power plants use or have used halogens in their operation.

One commenter stated that the peer-reviewed literature "does not rely on data from direct monitoring of the wastewater discharges; rather, the calculation is based on the facility's estimated coal consumption, the potential chloride in coal, and an assumed 0.02 bromide to chloride ratio in all coals." EPA disagrees with the suggestion that a mass-balance approach is not appropriate to use in the absence of monitoring data. In addition, the commenter did not provide any monitoring data to demonstrate their assertions. EPA agrees with one commenter who stated that "bromide content varies considerably among the various types of coal burned by power plants." Accordingly, EPA used coal type-specific and county-specific coal sample data to determine the best available estimate of bromine and moisture content in coal to use for each plant and coal type in the analysis. EPA's halogen loadings calculations are based on actual coal usage, which the commenter also recommends.

See the response to Comment Code 41 (Benefits) regarding the BCA, models for trihalomethane formation, and exposure to baseline TTHM levels.

EPA agrees with one commenter who stated that "[a]ny assessment of a potential regulatory approach to iodine must take into account the small quantities typically used by power plants for mercury reduction purposes as compared to naturally occurring iodine and non-coal sources of iodine." See the response to Comment Code 28 (EA – Halogens – Drinking Water Impacts) regarding "non-coal sources of iodine." As part of the final rule analysis, EPA estimated potential iodine loadings from steam electric power plants based on native iodine content in coal and addition of iodine for enhanced mercury emission control at plants likely to add halogens (see Section 6 of the Supplemental TDD).

Based on the data in the literature, EPA agrees, in part, with the commenter who asserted that "using iodine requires significantly less volume of added reagent than bromine[-]based approaches." Based on EPA's review of the literature, the addition rate of iodine at the boiler ranges between 1 to <30 ppm (DCNs SE06887A1, SE08148, SE08150, and SE08961); and EPA used 5 ppm in its loadings analysis (see the MS Excel file *Iodine Loadings for FGD Wastewater by Regulatory Option* (DCN SE08804)). In comparison, EPA used the average addition rate of bromine at the boiler of 90 ppm for subbituminous and lignite coal and 255 ppm for bituminous coal, based on data in EPRI (2016) (DCN SE08925) (see the MS Excel file *Bromide Loadings for FGD Wastewater by Regulatory Option* (DCN SE08802)). Based on this information in the rulemaking record, EPA disagrees with the commenter who states that the bromine addition rate is "more than 100 times" the iodine addition rate.

EPA agrees with the commenter who stated that "[a]ll coals contain some level of native halogen" and that "[l]imited data is available on native levels of iodine in all coal sources and ranks across the U.S." For its iodine loadings analysis, the Agency used a government document (Gluskoter, 1997 (DCN SE08958)) reporting iodine concentration in coal samples from 12 states and applied native coal content based on coal rank (see DCNs SE08956A1 and SE08956A2). This data set was significantly smaller and therefore more uncertain than the data set for native bromide concentrations in coal from the USGS' COALQUAL database described above. Iodine concentration in the collected bituminous coal samples ranged from 0.20 to 14 ppm. Without specific data on the Tinuum application rate, EPA cannot respond to the comment that "native levels of iodine in Eastern bituminous coal range to levels several times the Tinuum application rate."

One commenter stated that "[a]ny proposed regulation of the use of iodine – or halogens broadly – by coal-burning power plants must take into account the purpose for which such plants would apply supplemental halogens." EPA has taken into consideration compliance with other applicable regulations, including EPA's Mercury and Air Toxics Standards (MATS), as appropriate in this rule, including for the VIP requirements, which address halogens based on the performance of the model BAT treatment technology of membrane filtration. EPA is not regulating the use of halogens in the final rule. For additional discussion of regulatory approaches to bromide, see EPA's response to Code 36 (Regulatory Implementation - Bromide).

See the response to Comment Code 28 (EA – Halogens/Drinking Water Impacts) regarding impacts from wastewater discharge of bromides and impacts to downstream drinking water intakes.

14 FGD Wastewater – Chemical Precipitation

EPA received public comments on its methodology and the assumptions incorporated into the Agency's cost estimates for chemical precipitation (CP) systems for treatment of flue gas desulfurization (FGD) wastewater. The response has been organized into subtopics; identified by subheadings in the response below. The response covers the following subtopics.

- Chemical Precipitation Cost Estimates
- Chemical Precipitation as a Technology Basis

Chemical Precipitation Cost Estimates

As described in Section VII.B of the preamble, the EPA evaluated chemical precipitation as a technology option for flue gas desulfurization (FGD) wastewater. The EPA's rationale for selecting chemical precipitation as the technology basis for certain subcategories (discharges of pollutants in FGD wastewater from high FGD flow plants or low utilization electric generating units (EGUs)) is described in Section VII.C of the preamble. Chemical precipitation is also included as pretreatment in the technology selected for generally applicable BAT (low residence time reduction (LRTR)) and the technology selected for the Voluntary Incentive Program (membrane filtration).

Some commenters provided detailed cost methodologies and calculations that EPA reviewed when updating its cost estimates for the final rule. One commenter's chemical precipitation treatment overview and design basis are generally comparable to EPA's design, and EPA agrees with the commenter's statement that "costs were generally comparable."

EPA disagrees in part with one commenter who asserted that EPA should have used peak flows to estimate the cost to comply with the final rule. Estimating capital costs based on peak flows would result in a system that is unnecessarily oversized and using peak flows to estimate O&M costs would likely overestimate the annual costs incurred by plants. EPA used plant-specific average FGD flow rates to estimate capital costs and plant-specific optimized flows to estimate operations and maintenance (O&M) costs (see response to Code 11 (FGD Wastewater – General) and Section 5 of the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001) (Supplemental TDD)) for rationale and additional details on FGD flow rates including EPA's rational for using flow.

EPA agrees with some commenters that a well-designed chemical precipitation system should have some redundancy, however EPA disagrees with the commenters who asserted that two by 100 percent redundancy is necessary for every facility(see response to a similar comment in EPA's response to public comments from the 2015 Rule: DCN EPA-HQ-OW-2009-0819-6469). EPA included redundancy in its cost estimates for chemical precipitation, which EPA judged to be both appropriate and good engineering practice. As discussed in the 2015 response to comment document, on average across the industry, the redundancy for CP treatment systems is approximately two by 60 percent (*Incremental Costs and Pollutant Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report (DCN SE05831/SE05832)). While EPA understands that some companies may choose to install two by 100 percent redundancy and agrees with some commenters that the level of redundancy for a particular plant will vary, based on different utility operational strategies and capacity utilization,, public comments did not demonstrate that 100 percent redundancy is required for a typical system that is well designed and well operated. EPA's cost estimates are intended to represent reasonable average costs across the industry and therefore do not include the cost to install 100 percent redundancy. Commenters suggest that 100 percent redundancy is needed for plants with a capacity factor greater than 60 percent; however, the commenters did not submit data to demonstrate why additional redundancy is required, nor did commenters provide examples of where fully redundant FGD wastewater treatment systems have been installed to meet the 2015 BAT requirements, 2019 proposed BAT requirements, or other permit requirements on discharges of pollutants in FGD wastewater.

EPA notes that the population of 70 plants discharging FGD wastewater that EPA used for proposal and cited in one commenter's chemical precipitation cost methodology has been updated for the final rule. See EPA's *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule* memo (DCN SE08688) for more information on EPA's current FGD population, including information on known retirements and repowerings.

Chemical Precipitation as a Technology Basis

EPA received a public comment suggesting it should have selected CP as BAT. See Section VII of the preamble for a description of the regulatory options evaluated for the final rule. As part of the analyses for the final rule, the EPA did not update the 2019 proposed rule's estimated costs and loads for proposed option 1 (a regulatory option that reflects chemical precipitation alone as the BAT technology basis for all plants discharging FGD wastewater). See Section VII.B of the preamble for the rationale for not selecting chemical precipitation as BAT industry wide. EPA continued to evaluate chemical precipitation as pretreatment for two other wastewater technologies, low residence time reduction and membrane filtration, and as the technology basis for specific subcategories. As described in Section VII.C of the preamble, the EPA established BAT requirements for FGD wastewater based on chemical precipitation for two subcategories: high flow facilities and low utilization EGUs. See Section VII.C of the preamble and responses to code 9b (Subcategorization – Low Utilization EGUs) and code 9c (Subcategorization – Plants with High FGD Flows) for further details on these subcategories.

EPA agrees with one commenter who asserted that, without proper operation, it is possible that "delicate water chemistry characteristics" may lead to "reemission" events of mercury in flue gas. This commenter also asserted that chemical precipitation causes reemission events of mercury in flue gas, but did not provide data to support this claim. Lacking data to show otherwise, EPA maintains that the chemical precipitation data included in the record is representative of the treatment capability of a well-operated, chemical precipitation system that includes hydroxide precipitation, iron coprecipitation, and sulfide precipitation. EPA notes that organosulfide polymer, included in the Agency's technology basis for chemical precipitation, is well-suited for mercury removal. While mercury reemission could occur in the scrubber tower when mercury is in elemental state (not its ionic oxidized state) the record demonstrates that both elemental and ionic mercury will be removed either by the chemical precipitation system via the organosulfide, or by adsorption to particulates that settle out in the chemical precipitation system or that will be filtered out by downstream wastewater processing units (low residence time reduction and ultrafiltration in the case of the general BAT technology basis).

EPA disagrees in part with one commenter who asserted that chemical precipitation systems are "slow in their response times and often take hours or longer for their effects to be witnessed." EPA acknowledges that a period of time is required to optimize treatment efficacy following installation of any wastewater treatment technology; however, once optimization has been attained, a properly-operated and well-maintained system is sufficiently robust to address variability in FGD blowdown , and thus is capable of meeting the final effluent limits. EPA agrees with commenters who asserted that chemical reactions and settling within the chemical precipitation system require time to occur and that the design basis of EPA's cost estimate includes sufficient tank size to achieve the necessary residence time for chemical precipitation reactions and settling to occur. EPA also included costs for chemicals for pollutant monitors that plant operators could use to optimize the system if necessary. EPA included equalization tanks in its cost estimates which will mitigate or dampen the effects of variability in FGD blowdown.

EPA disagrees with one commenter who asserted that "systems using chemical precipitation, may also require the use of halogens" to achieve sufficient mercury removal. As described in the 2015 Technical Development Document (EPA-821-R-15-007), chemical precipitation achieves removal of mercury and other heavy metals through pH adjustments and the addition of lime, ferric chloride, and organosulfide, to precipitate out these dissolved and suspended solids. As described in section XIV.C of the final rule preamble, EPA concludes that implementation of BAT along with water quality-based effluent limitations where necessary is the proper way to address impacts from bromides and iodides at this time. As described in Section 6 of the Supplemental TDD, EPA does estimate the amount of bromide and iodide in FGD wastewater. See the *Mass Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants - Final Rule* and *Mass Balance Approach to Estimating Iodine Loadings from FGD Wastewater* memoranda (DCNs SE08957 and SE08960) for more information on current discharges in the industry.

15 <u>FGD Wastewater – CP + LRTR and CP + HRTR</u>

As described in section VII.B.1 of the preamble, the final rule establishes Best Available Technology Economically Achievable (BAT) for flue gas desulfurization (FGD) wastewater based on chemical precipitation followed by low residence time reduction (CP+LRTR) biological treatment. This response expands on the rationale discussed in the preamble in order to address issues raised by public comments categorized as Code 15 (FGD Wastewater – CP+LRTR). See Part 1 of this document for a list of Code 15 excerpts. The response has been organized into subtopics, identified by subheadings in the response below. This response covers the following subtopics:

- Cost Estimates.
- Pollutant Loadings and Removal Estimates.
- Support for CP+LRTR as BAT Technology Basis.
- Limitations/Site-specific Factors Including Coal Type.
- Technology Basis.

See responses to Code 43 (Numeric Limits) and *Supplemental Technical Development Document for the Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental TDD)* (EPA-821-R-20-001)for details on the revisions to the set of sampling data used to establish effluent limitations for BAT based on CP+LRTR.

Cost Estimates

For the final rule, Environmental Protection Agency (EPA) established BAT limitations for FGD wastewater based on CP+LRTR. EPA's estimates of plant-specific and industry total costs compared to the 2015 rule are presented in section VIII.A of the preamble and Section 5 of the Supplemental TDD.

Some commenters asserted that EPA's estimated capital costs necessary to comply with the final rule are underestimated. EPA disagrees and notes that its methodology, described in the Supplemental TDD and "*FGD CP+LRTR Cost Methodology" memorandum* (document control number (DCN) SE08594), uses plant-specific information from sources such as the (2010 Steam Electric Questionnaire) and other public sources. Based on data in the record, EPA assessed whether each plant would likely incur costs in order to comply with the final limitations and estimated what those costs would be. EPA agrees that specific plant-level costs may be higher or lower than the Agency's estimates due to additional plant-specific factors that may differ from EPA's assumptions such as those mentioned by a commenter ("distance from the installation to the unit, overall space limitations, redundancy requirements, terrain and associated infrastructure"). However, EPA's approach is consistent with the approach EPA has historically used to estimate plant-specific costs for effluent guidelines. Although some commenters assert that this approach likely underestimates costs for a particular plant, it is equally likely that EPA has overestimated costs for a particular plant because a plant may never need a system large enough to treat their maximum design FGD purge flow or the plant could save on costs by operating their treatment system more efficiently than EPA estimated. Industry innovation can also lead to lower costs than EPA estimated. These cost estimates are not precise enough to be used by an individual plant to select a technology to install at a particular facility, but rather are intended to provide a reasonable estimate of the industry-level impact of the rule. As such, EPA's estimated compliance costs may, in some cases, under or overestimate costs at any specific plant, but they still provide a reasonable estimate of the cost to a plant, and thus a reasonable basis for determining that the rule is economically achievable. EPA notes that the Clean Water Act (CWA) does not require EPA to make a precise calculation of costs. *See, e.g., CMA v. EPA*, 870 F.2d 177, 237-38 (5th Cir. 1989) ("The Act requires the EPA to 'take into account' the costs of BAT; it does not require a precise calculation. The EPA 'need make only a reasonable cost estimate in setting BAT'; it is sufficient if the EPA develops 'a rough idea of the costs the industry would incur'" (citation omitted).); *Kennecott Copper v. EPA,* 612 F.2d 1232, 1238 (10th Cir. 1979) (EPA has "wide leeway in its analysis of costs"); *BP Exploration & Oil Inc. v. EPA*, 66 F.3d 784, 799-800 (6th Cir. 1995) ("The CWA does not require a precise calculation of BAT and [New Source Performance Standards] NSPS costs" (citation omitted).); *NRDC v. EPA*, 863 F.2d 1420, 1426 (9th Cir. 1988) ("[T]he Act does not require a precise calculation of BAT costs").

Cost Factors. Commenters also asserted that EPA underestimated the cost factors used to calculate total installed costs from vendor estimates. EPA disagrees. For the final rule, EPA used revised cost curves submitted by an LRTR vendor that are similar to the proposed rule cost curves but take into account the costs for an ultrafiltration membrane polishing unit following the bioreactors. EPA derived its overall capital cost factor to supplement the vendor's costs from standard engineering factors presented in Peters and Timmerhaus' *Plant Design and Economics for Chemical Engineers.* One commenter stated directly that the supplemental cost factors presented in its comments are both based on "industry experience and standard engineering practice for all industrial sectors," but this commenter has not demonstrated that EPA's cost factors are unreasonable. EPA's cost factors are the average of those that are standard for a solid plant (e.g., coal briquetting), a solid-fluid plant (e.g., shale oil plant), and a fluid plant (e.g., distillation unit) presented in the table "Ratio Factors for Estimating Capital-Investment Items Based on Delivered Equipment Cost" (Peters and Timmerhaus Table 17, page 183). Similar to development of its indirect cost factor for the 2015 rule, EPA determined that averaging these factors is a reasonable approximation for a coal-fired power plant cost estimation.

These cost factors are a function of purchased equipment cost. To compare to the commenter's methodology, EPA put each cost factor in terms of the purchased equipment cost. After accounting for extra components already included in the vendor costs (e.g., contingency, electrical, instrumentation/controls), EPA determined that 44 percent of the vendor-provided costs are comprised of purchased equipment. EPA then applied the following list of capital cost factors from the Peters and Timmerhaus text to the purchased equipment costs (44 percent of the vendor-provided costs). Where EPA does not explicitly state a direct or indirect capital cost element, EPA estimated zero additional costs:

- For yard improvements (site work), EPA used a cost factor of 4.84 percent compared with 3 percent used by the commenter.
- For piping, including field-installed piping, EPA used a cost factor of 4.4 percent compared with 5 percent used by the commenter. While EPA's cost factor is slightly less than the commenter's factor, EPA notes that some of the piping-associated costs are included in the supplemental building cost (see below).
- For installation (tie-in/integration), including integrating the EPA used a cost factor of 19.8 percent compared with the commenter's value of 10 percent.
- EPA did not explicitly use a cost factor to supplement electrical costs because EPA judged that the installation cost factor includes all necessary electrical components to control the system, e.g., motor control center, as well as field wiring and connection to the plant air supply. The commenter used 5 percent.
- For construction ("general contractor general conditions"), EPA used a cost factor of 17.16 percent compared with the commenter's estimate of 5 percent. While the LRTR system is delivered to a site mostly equipped, EPA assumes this larger factor includes contingency, or "miscellaneous unidentified cost."
- For contractor's fee, the commenter used a factor of 12 percent. EPA estimated a lower contractor's fee (8.3 percent of the vendor costs, which equates to 19 percent of the purchased equipment only[53]) than is typical in the industry (10 to 20 percent). EPA judged this as reasonable and appropriate because the equipment is modular and will not require many additional materials and supplies for installation.
- The commenter supplemented a cost factor for contingency, or "miscellaneous unidentified cost" of 20 percent. EPA did not explicitly use a cost factor to supplement contingency as this is noted as being included in the vendor-supplied costs as "project contingency" (see the 2019 vendor cost information included in the "Updated LRTR Cost Memorandum" (DCN SE07120)). As described in Section 4.1.1 of the Supplemental TDD, much of the LRTR system is fabricated off-site as modular components resulting in a shorter, less complex installation process. In addition to the vendor-included contingency costs, EPA also included a factor to account for extra construction costs of 17.1 percent which provides additional contingency.
- For "client administrative and overhead" costs, the commenter included a cost factor of 7 percent. However, in the 2015 rule (EPA-HQ-OW-2009-0819-4499), the same commenter included no additional costs for these same components in the ABMet technology cost methodology. The need for this cost now, or for the LRTR system and not the 2015 estimate is not described in the commenter's arguments. EPA did not factor in "client administrative and overhead" additional costs for these expenses. Instead, EPA

[53] See the "FGD CP+LRTR Cost Methodology" memorandum (DCN SE08594) for a description of the vendor provided costs.

judged that these minimal costs would be covered by other factors, such as contractor's fees or contingency.

EPA further supplemented the vendor's costs by estimating costs for a building that includes HVAC (with a plant air supply connection), insulation, footings, a foundation, and doors. EPA notes that the commenter did not account for building costs, which is a crucial factor for operating in cold climates.

Overall, EPA supplemented the vendor costs with a factor of 57 percent to account for elements not already included in vendor estimates, including the supplemental building costs, compared with the commenter's factor of 67 percent. For the reasons stated above, EPA determined that this supplemental percentage appropriately contributes to a reasonable industry-level cost estimate. These factors are further explained in the "*FGD CP+LRTR Cost Methodology" memorandum* (DCN SE08594).

Equipment Installation. Commenters argue that EPA neglected to include additional costs for more robust foundation. EPA disagrees that this additional foundation is necessary for the LRTR system. In GE's (now SUEZ's) cost submittal to the commenter supporting the 2015 rule (EPA-HQ-OW-2009-0819-4499), the vendor assumed that the installation site for ABMet equipment would have soil bearing capacity of greater than or equal to 3,000 pounds per square foot with one inch or less of settlement. The commenter did not supplement GE's cost submittal or comment on whether this was an appropriate assumption at the time of the 2015 rule. For the proposed rule, EPRI did not provide data to demonstrate the average soil bearing capacity at plants nor were data provided to support the assumption that 88 percent of plants will require a deep foundation to increase the soil bearing capacity. Like the approach used for the 2015 rule, EPA did not supplement costs to account for a deep foundation that would require pilings and caissons. Costs provided by the LRTR technology vendor did not indicate supplemental foundation support would be required or were missing from their costs.

FGD Peak Flows. Some commenters assert that EPA underestimated the FGD wastewater flows used to size treatment equipment and estimate compliance costs. As described elsewhere in the response to comment document, EPA disagrees with these commenters. See response to code 11 (FGD Wastewater – General) for more information on the flows used to estimate compliance costs.

Equipment Redundancy. Some commenters assert that EPA underestimated chemical precipitation equipment redundancy. As described elsewhere in the response to comment document, EPA disagrees with these commenters. See response to code 14 (FGD Wastewater – Chemical Precipitation).

In the commenter's cost estimates for the LRTR technology, redundancy at "n+1" is accounted for. EPA agrees with this assumption and included a similar level of redundancy in its LRTR cost estimate based on input from the LRTR technology vendor (DCN

SE07120). The additional redundancy is already included in costs provided by the vendor; EPA did not include any extra cost factors to account for equipment redundancy.

Additional Costs. Some commenters assert that an inline selenium monitor is necessary for compliance with the final rule. As described elsewhere in this response to comment document, EPA disagrees with these commenters. See response to code 11 (FGD Wastewater – General) and code 35 (Regulatory Implementation – Compliance Monitoring).

EPA notes that this commenter supplemented the LRTR vendor's costs with a sodium bisulfite feed system; however, this reducing agent feed system for oxidation reduction potential (ORP) control is explicitly included in the vendor's cost submittal (see the 2019 vendor cost information included in the "Updated LRTR Cost Memorandum" (DCN SE07120)). EPA used the same cost factors described above to supplement the vendor-provided costs for this chemical feed system.

High Salinity FGD Wastewater. Several commenters remarked that biological treatment will experience adverse effects when the influent wastewater has a high concentration of total dissolved solids (TDS), specifically wastewaters that exceed 20,000 mg/L TDS. EPA disagrees that dilution will be needed for "high-TDS" or "high-ionic strength" FGD wastewater. As one commenter stated, "SUEZ had determined that biological treatment can function in FGD wastewater with TDS up to 35,000 milligrams per liter (mg/L)." Similarly, from operational data from its four full-scale systems and 14 pilot studies, Frontier has found that the maximum influent TDS to the SeHAWK is 36,000 mg/L (DCN SE07120). EPA's cost request to Frontier specified an influent to LRTR treatment TDS concentration of 24,100 mg/L (after chemical precipitation pretreatment). As such, the costs provided by the vendor for the LRTR technology account for TDS at this concentration on average, which is based on the average chemical precipitation effluent for all plants included in EPA's analytical database (EPA-HQ-OW-2009-0819-5640). EPA did not size larger systems for plants with higher TDS concentrations as one commenter suggested because the CP+LRTR cost methodology already accounts for a degree of overdesign. For each plant in EPA's FGD population, EPA estimated costs for a treatment system that can accommodate the full FGD purge flow, even though EPA expects that most plants will optimize their flow rates through increased recycle rates through the FGD scrubber. See more information on FGD flow optimization and EPA's cost estimation approach in Section 5 of the Supplemental TDD and [insert reference to relevant RTC]. In addition, as explained above, EPA's cost estimates are intended to provide a reasonable estimate of the industry-level impact of the rule.

Biotreatment Costs. Some commenters asserted that bioreactor costs for the LRTR technology are underestimated and do not represent performance consistent with the final selenium limitations. For the reasons provided below, EPA disagrees with these commenters. The proposed and final BAT limitations are based on pilot study data where the residence time, one to four hours, is similar to the bioreactors described in EPA's cost request to the LRTR vendors. The effluent selenium value that one commenter references, 50 micrograms per liter (µg/L), was provided in EPA's cost request as a daily maximum: "Assume that all measurements for selenium in the treated effluent should be below 50 micrograms per liter (µg/L)" (DCN

SE07823). EPA's final daily maximum is higher than this value (see section XIII.A.4 of the preamble for the final BAT limitations) and thus the estimated costs are appropriate.

Ultrafiltration Costs. Some commenters argue that "the cost of ultrafiltration is considerably higher than EPA has estimated." As described in the vendor cost estimate (DCN SE07120), LRTR system costs include costs associated with the ultrafiltration polishing system (filter and associated equipment including pump skids and an effluent tank (SE08587)). EPA does not estimate costs for an ultrafilter as a separate cost element; as a result, costs for just this component cannot be compared. In addition, because the ultrafilter is included in the vendor estimate, all cost factors are also applied to the cost of the ultrafilter as a function of being included in the vendor cost estimate. See the discussion of cost factors for the LRTR system earlier in this section. Commenters specifically mention one example, where a system is being designed and built at the Tennessee Valley Authority (TVA) Kingston plant to meet 75 percent of the 2015 monthly average limitations. Efforts made by plants to design a facility based on their prediction of what the final effluent limitations would be are not accounted for in EPA's analysis. Where plants have purchased, installed and are operating FGD wastewater treatment systems, EPA takes those existing FGD wastewater treatment systems into account in its estimates of costs and pollutant loadings (see the "FGD Treatment in Place Methodology" memorandum (DCN SE08629)). EPA did not take any cost credit for wastewater treatment systems still in the design phase, nor for plants that have not yet implemented or begun operating their treatment systems. As a result, EPA estimated costs for a full CP+LRTR system, accounting for no treatment in place, for Kingston. EPA's analysis for Kingston reflects current treatment with surface impoundments, and under the final rule, includes costs for a full chemical precipitation and LRTR system, including an ultrafiltration system.

EPA disagrees that operation and maintenance (O&M) costs for ultrafiltration are underestimated based on ultrafiltration membrane replacement and cleaning. EPA's O&M estimates are based on vendor costs for full-scale installations rather than limited pilot run times as commenters suggest. Costs provided by the LRTR vendor include two types of chemical cleaning for the ultrafiltration membrane: chemically-enhanced backwashes (CEB) that are run once per week on each ultrafiltration treatment train, and clean-in-place (CIP) procedures that typically occur once every 60 days (DCN SE08587). While the initial cost submittal provided by the LRTR vendor stated that the ultrafiltration membrane would require replacement every 12 years (DCN SE07120), more recent communication from the vendor clarified that membrane replacement is needed on an eight to 12 year schedule and that their cost proposal accounts for an 8.3 year replacement schedule (DCN SE08587). This replacement estimate accounts for the two cleaning procedures described above (CEB and CIP). Because LRTR systems have not been in operation for this period of time (eight to 12 years), the exact life of the ultrafiltration membranes is unknown, but based on available data this is a reasonable estimate and is similar to the estimate that SUEZ provided the commenter: eight to 10 years, depending on the characteristics of the wastewater being treated.

Pollutant Loadings and Removal Estimates

While EPA estimated toxic weighted pound equivalents (TWPEs) for all regulatory options, the CWA does not require EPA to evaluate TWPE to establish BAT limitations, and EPA does not use an analysis of dollars per TWPE (cost-effectiveness) as a decision criterion in establishing BAT, see response to code 5 (Regulatory Options - Compliance Costs Methodology.) See response to code 11 (FGD Wastewater – General) for more information on EPA's pollutant reduction methodology and evaluation of TWPE. In any case, setting BAT based on the CP+LRTR technology will produce the same order of magnitude of TWPE removal as chemical precipitation followed by high residence time reduction (CP+HRTR). Although the limitations for selenium are increased from the 2015 BAT limitations, it is by less than one order of magnitude. This still results in more than 75 percent removal of selenium from the current industry loadings and a 99 percent reduction of the selenium initially present in FGD wastewater (in the scrubber purge or blowdown). The limitations for mercury decreased by over one order of magnitude as compared to the 2015 limitations. Because mercury has a greater potential for toxicity than selenium (toxic weighting factor (TWF) of 110 for mercury compared to 1.12 for selenium), changes in the BAT limitations result in a reduction of discharges based on TWPE. See Table 1 for a comparison of the 2015 total TWPE to the 2020 total TWPE for mercury and selenium, based on discharging the industry-wide FGD flow at both the long term average and the monthly average limitation. EPA notes that some plants may be below these concentrations, as these limitations are an upper bound.

Table 1. 2015 TWPE vs. 2020 TWPE for Mercury and Selenium

Pollutant	TWF	FGD Industry Flow (MGD)	2015 Rule		2020 Rule	
			Limitation	TWPE	Limitation	TWPE
Long-Term Average						
Mercury	110	32.8	159 ng/L	1,748	13.48 ng/L	148
Selenium	1.12	32.8	7.5 µg/L	839	15.87 µg/L	1,776
Monthly Average Limitation						
Mercury	110	32.8	356 ng/L	3,913	34 ng/L	374
Selenium	1.12	32.8	12 µg/L	1,343	29 µg/L	3,246

EPA's cost-effectiveness analysis compares estimated compliance costs to the pollutant removals calculated using analytical discharge concentration data, as described in Section 6.2 of the Supplemental TDD. For CP+LRTR, estimated pollutant loadings and removals are based on effluent concentration data from CP+HRTR systems, as data for CP+LRTR data is limited. As described in Section 6.2.1 of the Supplemental TDD, the overall average effluent quality of the two treatment technologies is comparable. Pollutant limitations, on the other hand, are based on a statistical analysis of analytical data over time and are comprised of a long-term average effluent concentration coupled with a variability factor. For the CP+LRTR limitations, EPA uses data from six pilots to assess performance over time and variability. See section 8 of the Supplemental TDD. Also see responses to code 11 (FGD Wastewater – General) and code 43 (Numeric Limits) for further discussion of EPA's use of pilot studies as the basis for limitations.

Support for CP+LRTR as BAT Technology Basis

EPA acknowledges the support from commenters for selecting CP+LRTR (including ultrafiltration) as the BAT technology basis. EPA agrees with these commenters that LRTR is available, requires fewer facility footprint modifications, and is less expensive than the 2015 BAT technology basis for a similar level of treatment.

EPA further acknowledges the commenter's statement that leasing treatment systems is possible and has heard from other vendors offering treatment systems for lease. Costs associated with leasing treatment of either LRTR or membrane systems were not available for EPA to incorporate estimates of leasing costs as part of its cost estimation approach. However, EPA did evaluate the limited information it did receive on leasing see the Cost to Lease Flue Gas Desulfurization Wastewater Treatment memorandum (DCN SE08633).

Limitations/Site-specific Factors Including Coal Type

EPA disagrees with other commenters who asserted that the Agency should not establish BAT based on CP+LRTR because plants burn different coal types or switch coal type throughout their operation. Multiple commenters stated that varying the type of coal burned in a generating unit will impact a plant's ability to meet the BAT limitations using CP+LRTR due to differing flow rates, different constituents, and the timeframe in which coal blends can change. While FGD wastewater will vary from plant-to-plant, the concentration of each pollutant in FGD wastewater is not determined exclusively by the coal type burned, and more importantly, EPA has concluded that the constituent concentration ranges will not prevent biological treatment systems from meeting the BAT limitations. In addition, commenters have not provided data to support claims that burning different coals, coal blends, or the timing of changes in fuels result in concentrations of pollutants that cannot be treated by the CP+LRTR system. See response to comment code 11 (FGD Wastewater – General) for more information on the relationship between coal type and FGD wastewater treatment efficacy.

Other commenters questioned the limitations proposed for mercury and selenium. EPA disagrees with commenters who assert that mercury limitations have been set too low and do not account for full-scale operating variability. EPA used data from five pilot studies to develop the proposed limitations. As described in Section 8 of the Supplemental TDD, the final mercury limitations are also based on data from five pilots, but EPA has adjusted the data set based on comments on the proposed rule (removing mercury data from pilot ID 2027) and added data from one additional pilot study. See section X of the final rule preamble for discussion on data used to establish the limitations. EPA has judged that the pilot-scale CP+LRTR data in the rulemaking record is representative enough of full-scale CP+LRTR operations to establish limitations for the final rule. See response to code 43 (Numeric Limits) for EPA's rationale for using pilot study data and the methodology for calculating numeric limitations.

With regard to some commenters' claims that the daily maximum limitations for mercury and selenium are too stringent, EPA has revised the data set used to calculate limitations (see Section 8 of the Supplemental TDD for more details), and as a result, limitations in the final rule are not identical to proposal. See section XIII.A.4 of the preamble for the long-term averages and effluent limitations for FGD wastewater. The final mercury daily maximum limitation is increased from proposal. EPA disagrees with commenters who asserted that a higher selenium limitation is needed due to coal types, frequent load cycling, and other operational factors. As described previously in this section, these commenters have not provided data to demonstrate that these factors result in wastewater that cannot be effectively treated by the CP+LRTR system.

Technology Basis

As described in section VII.B.1 of the preamble, EPA chose CP+LRTR as the BAT technology basis for FGD wastewater and is rejecting CP+HRTR. As described in Section 5 of the Supplemental TDD, the technology basis includes an ultrafilter following the LRTR bioreactor that acts as a polishing step to remove suspended solids. Some commenters argued that the comparable CP+HRTR technology, the technology basis from the 2015 rule and evaluated in this rule as baseline, should be maintained as BAT for FGD wastewater because it is technologically available and economically achievable, and results in more pollutant reduction and therefore more reasonable progress toward the CWA goals than CP+LRTR. While EPA agrees that CP+HRTR is both available and economically achievable, the final rule preamble provides detailed explanation for why EPA has selected CP+LRTR as BAT and rejected CP+HRTR.

EPA agrees with commenters that the ABMet system is available, economically achievable, and being utilized by some plants to treat FGD wastewater. As described in Section 4 of the Supplemental TDD, the ABMet system is considered an HRTR system. The ABMet system, previously marketed by General Electric (GE), now marketed by SUEZ, is currently utilized by four plants to treat FGD wastewater (see the "FGD Treatment in Place Memorandum" (DCN SE08629). All HRTR systems are in combination with chemical precipitation as pretreatment and three utilize ultrafiltration for final polishing.

<u>Pollutant Discharge</u>. Several commenters argued that by EPA raising the limitations on selenium that this would "triple" the amount of pollution compared to setting CP+HRTR as BAT. While EPA is increasing the selenium limitations to values in the final rule (see section XIII.A.4 of the preamble), EPA disagrees with the commenter's assertion that setting BAT limitations based on the LRTR technology will triple the amount of pollution. Both the CP+LRTR and CP+HRTR treatment systems remove more than 99 percent of selenium present in untreated FGD wastewater. This is demonstrated by the analytical data used to develop CP+LRTR limitations

(see response to code 43 – numeric limits and section 8 of the Supplemental TDD). As explained in section XIII of the preamble, the long-term averages forming the basis of the selenium limitations for LRTR and HRTR are similar, and the higher selenium limitations for the LRTR systems are largely driven by increased short-term variability around that average, rather than a meaningful difference in long-term pollutant effluent concentrations. EPA disagrees that the LRTR technology will result in "significantly higher selenium levels" than the HRTR technology. Rather, EPA is considering new data that is available in the public record, compared the technology with 2015 baseline, and found that LRTR achieves comparable pollutant reductions and costs less.

CP+LRTR Performance. EPA recognizes that CP+LRTR may indeed be able to meet the 2015 BAT long-term averages, as one commenter states is true of Duke Energy's Marshall Steam Plant. As stated elsewhere, there is no meaningful difference in the long-term pollutant effluent concentrations between the two technologies, as they are comparable. EPA recognizes the CP+LRTR system may have short-term variability in performance, which the CP+LRTR data underlying the 2020 final limitations demonstrate. EPA set higher daily maximum and monthly average limitations for selenium not to encourage discharge of higher levels of selenium, but to recognize the inherent variability in the performance of the system. While EPA sets daily maximum limitations, these should not be used as the design basis for LRTR treatment systems and in practice they are not used because doing so would result in the facility being out of compliance with the monthly average limitations, which are lower than daily maximums. The objective of the daily maximum limitation is to allow for unexpected variability within the system. Instead, EPA expects facilities to design to meet the long-term average effluent concentrations. See section XIII.A of the preamble to the final rule regarding EPA's objective in establishing daily maximum and monthly average limitations. While plants may discharge at the daily maximum concentration, they are also required to achieve the monthly average limitation established in the final rule. See Section 8 of the Supplemental TDD.

Commenters noted the reference to 20 mg/L in footnote 19 of the proposed rule preamble (84 Fed. Reg. at 64,631), and commented that they believe the value was a typo and intended to be 20 ug/L. They also questioned EPA's use of this value as an arbitrary threshold with which to conclude that CP+HRTR and CP+LRTR have comparable performance. First, EPA agrees there is a units error: the footnote should have referenced 20 ug/L instead of mg/L. The purpose of the footnote is that both HRTR and LRTR achieve significant (>99 percent) removal of selenium. Long-term average effluent concentrations of selenium from both systems are well below the average selenium concentration achieved by technologies that do not target the removal of selenium (e.g., chemical precipitation). HRTR and LRTR achieve selenium effluent concentrations on the order of 10 to 20 ug/L, while chemical precipitation alone is in the thousands of ug/L, and untreated FGD wastewater can be several thousands of ug/L (see Section 6 of the 2015 TDD).

Operation. With the shorter residence time characteristic of the LRTR system, EPA expects that, in comparison to HRTR systems, wastewater treatment system operators may need to be more vigilant in monitoring and communicating with other process operators at the plant to proactively manage potential system upsets. In addition, EPA agrees with commenters who asserted that fine-tuning will be required for the LRTR system as it was discussed in the 2015 rule for the HRTR system. EPA expects that individual plants will still need to design and optimize these treatment systems to achieve performance necessary to meet the effluent limits established by the final rule.

Pollutant Reduction. EPA disagrees with commenters who asserted that there is insufficient data in the public record to allow for a meaningful comparison of LRTR with HRTR pollutant reduction. For the four full-scale LRTR systems used in the steam electric power generating industry to treat FGD wastewater, plant names, locations, applicable generating units, and a reference to utility documentation can be found in the "Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule" memorandum (DCN SE08688) as well as the "FGD Wastewater Treatment in Place at Steam Electric Power Plants" memorandum (DCN SE08629). The names and locations of plants conducting pilot studies of the LRTR technology have been held as confidential business information (CBI) at the request of utilities and/or vendors; however, the influent and effluent concentrations, which commenters refer to as "effluent monitoring data" are non-CBI and are available in the section 8 of the Supplemental TDD. EPA chose to mask the plant names and locations so that the actual concentration data used to calculate limitations could be made public. The record also includes other documentation from vendors and industry trade groups describing the performance of the treatment technology (DCN SE06616; DCN SE08566).

Short-term Pollution Impacts. EPA agrees that discharges of selenium, mercury, and other pollutants in FGD wastewater can have negative effects on the environment and human health, as documented in extensive scientific literature and case studies. See the *Supplemental Environmental Assessment for Final Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2020 Supplemental EA) (EPA-821-R-20-002), which included a focused literature review and quantitative modeling of potential impacts resulting from discharges of the evaluated wastestreams. See also the *Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2015 Final EA) (EPA-821-R-15-006) and the *Supplemental Environmental Assessment for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2019 Supplemental EA) (EPA-821-R-19-010) for further discussion of the environmental and human health effects of these pollutants, including a literature review. While the CP+LRTR technology could result in potential daily spikes, EPA expects these spikes to be infrequent. Based on one commenter's statement that "three to eight micrograms per liter (µg/L) [of selenium] can kill fish," EPA notes that the 2015 BAT limitations, based on the CP+HRTR technology, had monthly average and daily maximum limitations in excess of these concentrations. The final rule establishes effluent limits based on the performance the technology can achieve. Apart from this rule and ELGs generally, water quality-based effluent limits required by the CWA to be included in NPDES permits where necessary to meet applicable water quality standards, are designed to protect environmental endpoints, such as aquatic life. Again, EPA expects plants to discharge pollutants at a concentration at or near the daily maximum limitation only on an occasional basis, if ever. As discussed in Section 8.2.5 of the Supplemental TDD, "variability around the long-term average occurs during normal operations, which means that plants might, at times, discharge at a level that is higher (or lower) than the long-term average." The objective of the daily limitation is to allow for this variability within even the well-operated system.

EPA identified no documented cases of acute human health impacts resulting from short-term exposure to pollutants in the evaluated wastestreams under historical or current discharge practices. Peak short-term FGD wastewater pollutant loadings under the final rule will be significantly less than under current discharge practices (see *Pollutant Loadings Associated with Current Discharges of FGD Wastewater and Bottom Ash Transport Water* (DCN SE08690) and Section 6 of the Supplemental TDD for more information on EPA's pollutant loadings analysis). As stated above, this is a technology-based rule looking at what the treatment technology can achieve, not the water quality impacts, which are addressed under a different, separate authority for water quality-based effluent limitations. See CWA section 301(b)(1)(C).

<u>Reasonable Forward Progress</u>. In response to one commenter's assertion that choosing CP+LRTR as the BAT technology basis is not making "reasonable forward progress", EPA disagrees. In any event, EPA's legal obligation under the CWA is to establish BAT after consideration of the factors specified in section 304(b) of the Act. As described in the "FGD Wastewater Treatment in Place at Steam Electric Power Plants" memorandum (DCN SE08629), only eight of the 61 plants currently discharging FGD wastewater have either LRTR or HRTR technology. Despite changes to the effluent limitations established by the 2015 rule, these requirements still achieve reasonable forward progress over BPT and what is currently implemented on an industry-wide basis. See response to code 1 (Legal) regarding this final rule's compliance with Clean Water Act section 301, 33 U.S.C. §1311. Also see section VII.B.1 of the preamble for more details on the rationale for selecting CP+LRTR as the BAT technology basis.

<u>LRTR and HRTR Distinction</u>. A commenter stated that HRTR and LRTR "are not separate technologies." While EPA agrees that both systems operate using the same treatment mechanism (anaerobic biological reduction specifically designed to remove selenium, nitrate/nitrite, and other pollutants), EPA disagrees with the commenter that there is "no industry standard that defines the demarcation between HRTR and LRTR in terms of hydraulic retention time." EPA has observed that biological treatment systems installed at plants or available on the market fall into one of two categories: those designed with longer residence times (i.e., the biological treatment systems evaluated for the 2015 rule) and those designed with shorter residence times (which have become available on the market more recently). Therefore, EPA differentiates biological treatment systems based on residence time in order to reflect the reality that these two categories of systems are different in practical terms, especially in terms of costs and space requirements. While EPA's differentiation might not meet the commenter's definition of an "industry standard," the commenter has not demonstrated that EPA cannot draw a reasonable distinction between these two categories of biological treatment systems that is relevant when evaluating BAT technology bases.

16 FGD Wastewater – CP + HRTR

No comment excerpts were received on this topic.

17 FGD Wastewater – Membrane Filtration

As described in section VII.B.3 of the preamble, the final rule establishes a Voluntary Incentives Program (VIP) for plants to implement new BAT limitations if they adopt additional process changes and controls that achieve limitations on mercury, arsenic, selenium, nitrate-nitrite, bromide, and TDS in FGD wastewater, based on membrane plus pretreatment technology. This response expands on the rationale discussed in the preamble to address specific issues raised by public comments concerning the VIP, categorized in Code 17 (FGD Wastewater – Membrane Filtration). See Part 1 of this document for a list of Code 17 excerpts. The response has been organized into subtopics, identified by subheadings in the response below. This response covers the following subtopics:

- Current level of development of membrane filtration for FGD wastewater.
- Technological availability of membrane filtration for FGD wastewater.
- Cost estimate methodology for membrane filtration.
- Management of brine resulting from use of membrane filtration.
- Pollutant loadings and removals estimated for membrane filtration.

See responses to Code 43 (Numeric Limits) and section 8 the *Supplemental Technical Development Document for Final Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental TDD) (EPA-821-R-20-001) for details on the sampling data used to establish BAT effluent limitations for the VIP.

Current level of development of membrane filtration for FGD wastewater

As described in both the preamble and the Supplemental TDD, EPA is aware of full-scale membrane filtration systems being used for the treatment of FGD wastewater at locations in China, South Korea, and Finland. However, as explained in the preamble, EPA was unable to obtain operation, maintenance, or performance information from these foreign plants, either directly from the facility, from the vendors, or from site visits. Thus, EPA does have information on how these systems are configured or operated, what levels of reductions they achieve, or whether there are any particular performance difficulties that result from continuous operation, and importantly, how applicable these operations would be to plants across the United States. See Section VII.B.1 of the preamble for discussion on the technological availability of membrane filtration for FGD wastewater.

EPA used vendor-provided cost estimates and pilot testing data for advanced membrane filtration technologies designed to treat high total dissolved solids (TDS) and total suspended solids (TSS) as described in Section 4.1.3 of the Supplemental TDD in its analyses for the final rule. Some commenters agreed with EPA's proposed conclusion that there are no domestic applications of membrane technology to treat FGD wastewater. One commenter suggested that there is a full-scale membrane system operating at a U.S. steam electric power plant. EPA investigated this commenter's claim and found it to be incorrect. See DCN SE08619.

Technological availability of membrane filtration for FGD wastewater

As described in Section VII of the preamble, EPA is establishing BAT effluent limitations in the VIP for discharges of pollutants found in FGD wastewater based on membrane filtration with encapsulation for brine management as the technology basis. The VIP is, as the name suggests, a voluntary program. As such, these VIP requirements are not national standards that all coal-fired steam electric plants are required to achieve. Instead the VIP option provides an incentive for plants to comply with more stringent effluent limitations in exchange for additional time to evaluate, pilot, and install a technology more advanced than the technology that serves as the basis for the generally applicable BAT requirements. Plants may elect to meet these VIP limitations with any treatment technology they choose. Plants may select treatment technologies other than membrane filtration (e.g., thermal systems), may elect not to participate in the program, or in certain circumstances may elect to transfer out of the VIP.[54]

EPA agrees with commenters who asserted that membrane filtration is not BAT industry wide. In the final rule concludes only that membrane technology will likely be available by 2028 on a site-specific basis. Although EPA has continued to investigate the availability and economic achievability of this technology, as well as any associated non-water quality environmental impacts, EPA cannot predict with certainty that the technology will be nationally available in 2028.

The final rule establishes generally applicable BAT limitations based on CP+LRTR. See Section VII.B.1 of the preamble for EPA's rationale for selecting CP+LRTR as the generally applicable BAT technology basis instead of chemical precipitation followed by high residence time reduction (CP+HRTR) or membrane filtration. See the *Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA) (EPA-821-R-20-004) regarding EPA's evaluation of economic achievability of each of the regulatory options evaluated as part of the final rule.

Some commenters have indicated that site-specific concerns related to encapsulation may pose technical challenges with requiring membrane filtration industry-wide now (discussed in further detail below). Another commenter asserted that membrane systems can easily be started and shut down and operated as needed, suggesting this technology could be used for peaking or low-utilization plants; however the commenter did not provide any data to support this claim. As described in section VII.B.1 of the final rule preamble, EPA agrees that, for the majority of domestic plants, membrane technology is not feasible due to cost or operational limitations.

[54] See 40 CFR 423.13(o).

However, for those facilities that choose to pursue this technology, the VIP program offers additional flexibility and more time to pilot, plan, install and operate a membrane treatment system to treat FGD wastewater.

Cost estimate methodology for membrane filtration

Some commenters asserted that technologies or combinations of technologies other than the VIP BAT technology basis may result in lower overall capital and operating and maintenance costs depending on plant configurations, wastewater characteristics, treatment available, and other circumstances including geographic location and relative climate conditions. Other commenters correctly note that EPA assumes for purposes of its loadings analysis for the VIP that facilities employing membrane filtration would achieve zero discharge; however, given the lack of data on long term performance of membrane treatment systems for FGD wastewater, there may be some plants where zero discharge is not feasible, and others may require discharges from time to time even when primarily operating to zero discharge.[55] Thus, the VIP limitations do not require zero discharge of FGD wastewater. See section VII.B.1 of the preamble for further discussion on zero discharge.

Some commenters asserted that EPA underestimated costs because treatment support systems were not included. As described in the Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology memorandum (DCN SE08625), EPA's cost estimates for membranes account for treatment support systems including all tanks and pumps, chemical addition costs and addition equipment, and clean-in-place systems. In response to comment, EPA supplemented its proposed cost estimates for the final rule to account for any missing cost elements from individual vendors. For at least one vendor, previous estimates were not accounting for sufficient energy and included an error in membrane cleaning costs (DCN SE08563). EPA's cost estimates for the final rule also include costs for solidification and disposal of solids generated by the membrane system. See the Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology memorandum (DCN SE08625) for a description of how vendor data were used to estimate treatment system costs.

EPA agrees with the commenter who stated that "pretreatment is critical for attaining/maintaining reliable operation of membrane-based filtration treatment systems." Several commenters expressed concern that EPA underestimated costs associated with pretreatment of FGD wastewater prior to membrane filtration. As described in section VII.A.1 of the final rule preamble, EPA updated its cost estimates to include the costs of chemical precipitation as pretreatment for the membrane filtration technology. The chemical precipitation system used for EPA's cost estimates is described in detail in Section 5 of the Supplemental TDD. (See also the Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology memorandum (DCN SE08625) and the CP cost methodology memorandum (DCN

[55] While EPA's assumption of zero discharge for the VIP is a reasonable assumption for estimating costs and loads, this analytical step does not represent a finding that zero discharge technologies are BAT, and thus does not obviate the need to analyze treatment efficacy and variability.

SE08593).) The chemical precipitation pretreatment system includes costs for equalization, hydroxide precipitation, iron coprecipitation, and sulfide precipitation for treatment of heavy metals, pH adjustment, and antiscalant. Solids removal is achieved through clarification and solids dewatering via a filter press. EPA's cost estimates also account for pretreatment solids handling and transportation and disposal. Chemical precipitation costs are estimated with separate cost curves from the membrane filtration cost curves as the membrane filtration cost curve does not include costs for pretreatment.

As described in section VII.A.1 of the final rule preamble, in response to public comments, EPA updated its cost estimates for the VIP to include chemical pretreatment. This results in a higher cost estimate than proposed, but also in a costed technology basis that matches the treatment systems installed in the pilot tests that generated the data used to develop limitations. See Code 43 (Numeric Limits) and the Supplemental TDD for discussion of the data used to calculate effluent limits. In addition, chemical precipitation pretreatment provides a more robust pretreatment system to achieve removal of suspended solids (or particles) and scaling and foulants prior to the membrane treatment system. Some membrane filtration vendors stated that the only pretreatment necessary for operation of a membrane system to treat FGD wastewater is TSS removal (DCN SE08589, DCN SE08563, DCN SE08579). Despite these vendors' claims EPA still concluded the full chemical precipitation system, with hydroxide precipitation, iron coprecipitation, and sulfide precipitation is the most appropriate pretreatment for membrane filtration treatment systems based on the information available in the record. Moreover, based on conversations with these vendors, EPA expects that the estimated cost of a chemical precipitation pretreatment system should cover any level of pretreatment required by an individual plant.

As described in the Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology memorandum (DCN SE08625), EPA developed a membrane filtration cost curve using vendor-specific costs from three vendors, and then averaged the three values together across a variety of FGD wastewater flows to generate one average membrane filtration cost curve. Membrane filtration costs account for only the membrane filtration and brine management components of the system; pretreatment costs are estimated separately as discussed earlier in this response. The provided costs are based on treatment of an average untreated FGD purge stream with an average chloride concentration of 7,180 mg/L and an average TDS concentration of 33,300 mg/L. These average concentrations are based on FGD wastewater purge data from the Steam Electric Analytical Database for the 2015 ELG (DCN SE05359). The combined vendor costs assume an average percent recovery of over 70 percent, based on data from three different membrane filtration vendors. Some vendors assumed closer to the 80 percent recovery value referenced by commenters, but other vendors assumed a lower recovery. At least one vendor also included a capacity buffer, oversizing the system to account for decreased membrane performance over time between membrane replacements. None of the vendor estimates account for chemical precipitation pretreatment. Because EPA included a more advanced pretreatment system in its cost estimates than what was used in the vendor cost estimates, EPA expects that the recovery rates provided by the vendors may overestimate costs should plants be able to operate at or above these estimated recovery rates. After considering the various scenarios presented by vendors, EPA expects that plants should be able to mitigate excess scaling/fouling and pretreatment upsets such that EPA's estimates are a reasonable approximation of costs. EPA's cost estimates are based on data from three separate vendors, one of these vendors reported that there will be a decline in the membrane recovery over time, likely 10 percent per year (DCN SE08563). This decline in recovery over the life of the membranes is accounted for in vendor cost estimates by factoring in oversized membranes at the time of installation, and include costs for membrane replacement every 2 to 2.5 years.

Some commenters argue that EPA overestimated membrane filtration costs by failing to consider lower FGD purge rates, using maximum purge rates, or by using outdated coal usage data. As described in Section 5 of the Supplemental TDD, EPA does factor in lowering FGD purge rates by accounting for expected recycle within the FGD system. Where data were available on design and operating chlorides concentration, EPA estimated that plants would recycle FGD purge within the scrubber to decrease the size of the treatment system required. Second, EPA's methodology uses average flows to estimate O&M costs but sizes equipment for capital costs that incorporate a design capacity. See the response to Code 14 (FGD Wastewater – Chemical Precipitation) for how design capacities are factored into costs. Finally, EPA uses plant-specific FGD purge flow data to the extent that information is available in the rulemaking record. The methodology used to identify FGD purge flows and calculate optimized FGD flows is described in the Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings (DCN SE08630). Only where FGD purge flow data were not available through other sources, such as the Steam Electric Survey or permits, does EPA use EIA coal usage data to estimate a purge flow. As described in the Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings (DCN SE08630), EPA has updated its methodology for the final rule to use 2018 EIA data to estimate these FGD flows where appropriate.[56] EPA does not adjust FGD purge flows based on EIA coal usage or electricity generation data because the data do not show specific trends over time. At the generating unit-level, data from EIA show both increases and decreases in amount of coal burned and electricity generation year to year. As discussed in the Final Revisions to the Steam Electric ELGs: Fly Ash Availability memorandum (DCN SE09070), EPA's analysis of EIA data on coal consumption and ash generation shows that the plant operation can vary from year to year.

One commenter submitted their own cost estimate for membrane treatment and stated that EPA underestimated costs by 10 times and EPA underestimated waste solidification and disposal costs by $20 to $40 million per year. This commenter did not provide sufficient detail to explain why EPA's cost estimation methodology does not produce a reasonable estimate of costs expected to borne by the industry, which is the level of detail the Agency considers necessary for cost estimates to support a BAT decision in an ELG. For example, the commenter does not provide support as to why it chose different cost factors than EPA, why their cost factors are more appropriate than the factors EPA relied upon, or why EPA's factors are unreasonable. EPA's costing methodology is described in Section 5 of the Supplemental TDD, and in the supporting

[56] The 2018 EIA data is the most recent year for which final data has been released.

Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology memorandum (DCN SE08625). See also response to code 5 (regulatory options – compliance costs methodology) for further discussion of the statutory basis for EPA estimates. EPA updated its methodology description to include further detail on the specific components included for direct and indirect capital costs, transportation and disposal, and solidification components, to address commenters' incorrect assumptions that these costs were missing. EPA's cost methodology is intended to reasonably estimate costs at the industry-level. As much as possible, plant-specific data were used to estimate plant-specific costs; however, some plant-level estimates may be under or overestimates based on the data available. For example, EPA's estimate of chemical costs at one plant or distance of piping required at another may be over or underestimates of actual costs. EPA expects that at the industry-level, these over and underestimates average out to a reasonable estimate of the costs to the industry as a whole.

As mentioned by same commenter, the underlying cost data provided by membrane filtration vendors, used as the basis for EPA's cost methodology, is claimed as CBI. However, because data from three vendors was used to develop the methodology, and all three vendors claimed the individual data as CBI, EPA was able to aggregate the data into the non-CBI cost curve presented in the Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology memorandum (DCN SE08625). As described in the memorandum, this approach was used to allow for transparency and includes as much non-CBI information as possible in the record regarding the estimates for the membrane filtration technology.

EPA is aware of some vendors that offer their systems for lease. Comments from vendors including Purestream and Frontier Water Systems mention leasing FGD treatment systems but neither comments provide cost data associated with leasing the system. EPA followed up with Purestream more specifically related to their comments on the proposed rule, and discussed their business model in detail, which is based on leasing treatment systems (DCN SE08590). Purestream declined to provide details on costs associated with its thermal treatment system; therefore, without costing data with which to fully analyze the costs of leasing membrane or thermal treatment systems, EPA is unable to use this option in its compliance cost estimates. See response to Comment Code 5 (Regulatory Options - Compliance Costs Methodology) for additional discussion of leasing.

Management of brine resulting from use of membrane filtration

EPA agrees with commenters who asserted that plant-specific considerations will need to be addressed when considering encapsulating brine generated by the membrane system. EPA included an extended compliance deadline for the BAT limitations in the VIP to allow for additional pilot testing needed to evaluate site-specific details, such as determining the most effective encapsulation blend for a plant. EPA's record shows that research in this area continues to advance (DCN SE08589 and DCN SE09219); however, the record shows that while plants can use a range of combinations of fly ash, lime, brine, and Portland cement to achieve effective encapsulation, the exact encapsulation blend will vary from plant to plant and requires testing at each plant to optimize.

EPA agrees that "encapsulation with fly ash is only one of several available methods for dealing with membrane filtration brine." As described in the preamble and the Supplemental TDD, for the final rule EPA estimated costs for three brine management alternatives:

- Membrane filtration with encapsulation of the brine, and disposal of solids in a landfill.
- Membrane filtration with crystallization of the brine, and disposal of solids in a landfill.
- Membrane filtration with deepwell injection of the brine.

EPA's cost estimates indicate that for all steam electric plants discharging FGD wastewater, encapsulation of the brine is the least cost brine management alternative. EPA has used the costs of the membrane filtration with encapsulation system as the basis for its economic evaluation of the membrane filtration technology because EPA expects that, when given the choice, most plants would select the least cost treatment configuration in order to achieve requirements based on a membrane filtration technology. EPA did not estimate costs for treatment of brine by a centralized waste treatment (CWT) facility as EPA is not aware of any CWTs that treat FGD wastewater; however, this may also be a viable brine management option for some plants.

Some utilities indicated in their comments that there may not be enough available fly ash (due to beneficial use or sale of fly ash) to solidify the brine generated from a membrane filtration system. EPA evaluated several years of data from the Energy Information Administration (EIA), to quantify the amount of fly ash available and the amount of fly ash used or sold by plants. As described in the Final Revisions to the Steam Electric ELGs: Fly Ash Availability memorandum (DCN SE09070), the amount of available fly ash varies from year to year due to a variety of factors, including energy generation and amount of coal burned and demand for fly ash in accessible markets. Due to market variability, it is possible that plants may have excess fly ash one year and insufficient fly ash another year. Despite this uncertainty, EPA assumed for its cost estimates that most plants would have sufficient fly ash available onsite most years (based on EIA data), and did not account for lost fly ash sale revenue at some plants that normally sell fly ash or include costs to purchase fly ash, or to procure additional pozzolonic materials (e.g., Portland Cement) at that plants that do not have enough fly ash available. This may underestimate the costs of brine management assumed in EPA's analysis of regulatory options; however, EPA also evaluated more costly brine management alternatives, and this range of costs captures situations where fly ash sales might lead to higher costs for the solidification alternative.

EPA disagrees with some commenters who asserted that encapsulation solids are not compatible with landfills. Data from membrane and encapsulation vendors indicate that these encapsulation mixtures, for both eastern bituminous and Powder River Basin coals, do meet toxicity characteristics leaching procedure (TCLP) testing requirements (EPA-HQ-OW-2009-0819-7644). Furthermore, there is currently at least one plant generating FGD wastewater brine with a thermal technology and sending that brine to an existing, on-site landfill after using it to condition ash (DCN SE08964).[57] EPA agrees with other commenters who asserted that it will take time to permit and construct necessary landfill space for the solidified brine byproduct and that is part of the reason that EPA has extended the compliance deadline for the VIP (see preamble section VII.B.3).

Commenters also reference other methods of brine disposal, such as fly ash humidification. Commenters mention this as a potential method to allow for beneficial reuse or disposal of the brine. Lacking more specific details on this process, EPA is unable to assess whether this application is feasible at all plants because EPA does not know that all plants use water that could be replaced with brine, that plants would be able to use all of the brine produced for this purpose, or that the use of brine for fly ash humidification would still allow plants to meet their product specifications for fly ash sales. As such, EPA has not incorporated this process as part of the membrane filtration technology basis. However, this does not preclude plants from using this process as a brine management method to achieve compliance with the final rule as is done at the one facility discussed above.

EPA's technology basis for membrane filtration does not include "paste" technology for brine management. EPA's estimates reflect all plants encapsulating brine to a solid material and then transporting that material in dump trucks, rather than transportation via pipes as a pumpable paste, because paste technology is still under development. As described in section VII.B.1 of the preamble, paste technology is a method for disposing brine. Like encapsulation, brine is mixed with fly ash and lime, but in different ratios than encapsulation. Since proposal, EPA has learned of ongoing pilot studies of this technology (DCN SE08619), but no additional details on mix ratios, costs, or feasibility of this brine management option for all plants have been obtained. Because EPA lacks sufficient data to fully evaluate this technology, EPA considers this a forthcoming technology and has not included paste technology as part of the membrane filtration technology basis.

EPA agrees with commenters who asserted that fly ash availability varies within the industry. Data available from EIA demonstrates that the amount of fly ash generated at any individual plant can vary year-to-year. In addition, the marketable opportunities for fly ash vary based on location, year, and the class (C, F, or unclassified) of fly ash generated. EPRI's estimates of the amount of fly ash sold on average overestimates the amount of fly ash sales across all plants. EPRI's methodology assumes 60% of fly ash is sold at the case study plant used in their examples included in public comments (EPA-HW-OW-2009-0819-8293-A1). Based on EIA data for 2018, on average plants only sold 34 percent of fly ash and as many as 22 plants of plants incurring FGD costs under the final rule did not sell any fly ash in 2018.

EPA agrees that wastewater concentrations may impact the type and amount of chemical additives required for solidification. The costs estimated by EPA are a reasonable estimate of the

[57]Ash conditioning does not create as many pozzolonic reactions as the solidification process using fly ash and lime that EPA assumed in its analyses, and thus conditioning would be expected to release more pollutants into its leachate than fully encapsulated material.

amount of lime and fly ash required to encapsulate the brine generated by the membrane treatment system. Data from vendors and industry members indicate that the exact encapsulation blend (combination of brine, lime, and fly ash) can vary; however, EPA's methodology uses an average to estimate the costs across all plants discharging FGD wastewater (DCN SE08589 and DCN SE09219) which are a reasonable estimate at the industry-level. EPA agrees that it will take time for plants to perform pilot tests and determine the exact ratio of chemical additives needed and has extended the compliance date for the VIP in part to allow time for this necessary testing.

EPA disagrees with commenters who suggest that EPA's estimate of on-site disposal is more expensive than off-site disposal. As a component of the cost estimates, EPA estimates costs for either on-site or off-site disposal. As described in Section 5.2.1 of the Supplemental TDD, EPA used data from the Steam Electric Survey and other public sources to identify which plants operate on-site landfills containing FGD solids. Where plants already operate such landfills, EPA anticipates plants will continue to dispose of FGD solids in the landfill or will activate an inactive landfill as part of installing the FGD technology option. Similar to the 2015 transportation and disposal methodology, EPA's cost estimates account for the following costs for on-site or off-site disposal:

- On-site Transportation and Disposal.
    - O&M costs associated with transportation in an open dump truck.
    - Capital and O&M costs associated with disposal of additional solids (brine and lime) in an existing landfill by either expanding the existing landfill or building a new landfill.
- Off-site Transportation and Disposal.
    - O&M costs associated with transportation in an open dump truck.
    - O&M costs associated with costs to utilize an off-site non-hazardous landfill for disposal.

See the Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology memorandum (DCN SE08625) for details on EPA's assumptions associated with these costs. On-site transportation and disposal costs include both capital and O&M cost components. On-site options tend to have higher capital costs (the power plant pays for the landfill construction) but much lower operating costs when compared to off-site options. Off-site operations instead build these costs, O&M costs, and profit margins into the tipping fees charged. The power plant must also transport the ash further distances to the off-site landfill. Thus, when comparing the estimated *total* costs (either annualized or net present value), off-site transportation and disposal tends to have much higher costs.

Pollutant loadings and removals estimated for membrane filtration

EPA received a variety of comments on bromides, also see excerpts and the response summary to code 36 (Regulatory Implementation – Bromides). As described in section XIV.C of the preamble, EPA is not finalizing limitations on bromides beyond those included as part of the VIP option for FGD wastewater. See preamble section VII for discussion of EPA's BAT analysis. In the absence of an industry-wide technologically available and economically achievable technology based on the Clean Water Act statutory factors, discharges of bromides are best addressed using site-specific, water quality-based effluent limits. See section XIV.C of the preamble for additional discussion of bromides.

One commenter stated that its estimates of pollutant reductions under the VIP option are "roughly comparable" to EPA's estimates. As described above, EPA has revised its cost estimates for the VIP. As described in the preamble, EPA now estimates that fewer plants will elect to select the VIP option than at the time of the proposal (i.e., 8 plants rather than 18). Regarding the pollutant loadings, EPA's methodology remains largely unchanged for final, except for the updates to the population and FGD wastewater flows. See Section 6 of the Supplemental TDD for a description of EPA's methodology for estimating the pollutant loadings and removals associated with the membrane filtration technology option.

18 FGD Wastewater – Other Technologies

Other Technologies as Technology Basis

EPA received and considered information provided by commenters on the Sulfur Modified Iron (SMI)-III technology. Based on EPA's review of the vendor's website (smiwater.com), the SMI-III technology is marketed to the Steam Electric industry as a potential solution for pond dewatering, which is outside the scope of this rulemaking. The data provided in public comments does not indicate the type of wastewater in the full-scale SMI installations, and the vendor's website does not specify whether SMI-III has been tested on flue gas desulfurization (FGD) wastewater. While two of the plants referenced in the public comments do list "power plant" and "power generation" as the client and market sector, data on the type of wastewater and other constituents present in the treated waste stream is not available. EPA appreciates additional information on treatment technologies that may be used to treat FGD wastewater; however, the data available on the SMI-III system was insufficient to evaluate it as a basis for best available technology economically achievable (BAT) limitations. EPA notes that the final rule does not preclude the use of any specific technology(ies) or require that specific technology(ies) must be used.

EPA also received information in public comments on carbon adsorption technologies. EPA notes that sorption technology is identified in the 2015 rule Technical Development Document (TDD) as an emerging technology for the treatment of FGD wastewater. EPA reviewed one commenter's discussion on activated carbon technologies, specifically Carbonxt's "Activated Carbon Adsorption." This technology is described as only targeting mercury. EPA notes that the type of chemical precipitation included in the technology bases evaluated for the final rule, which includes hydroxide precipitation, iron coprecipitation, and sulfide precipitation, targets heavy metals in addition to mercury, most notably arsenic. Carbonxt's Cxt-WetJect™ is described as a system that relies on injection of activated carbon to capture mercury that has been converted from the air phase into the liquid phase using a proprietary non-halogenated additive. Commenters note that "in a full-scale demonstration, the Cxt-WetJect™ both reduced mercury emissions in the air and liquid phase." Air emissions from steam electric plants are outside the scope of this rulemaking. See section VII.B.1 of the preamble for a description of EPA's rationale for selecting CP+LRTR as the BAT technology basis to control the discharge of pollutants in FGD wastewater. EPA notes that the final rule does not preclude the use of any specific technology(ies) or require that specific technology(ies) must be used. Steam electric plants can use activated carbon injection as part of an overall compliance strategy, but they would most likely require additional wastewater treatment to achieve the final BAT limitations, described in section XIII.A.4 of the preamble.

Thermal Treatment as a Technology Basis

One commenter suggested that "RO and thermal technologies have progressed to higher technology readiness" and "should be favorably considered." EPA evaluates technological availability when it selects a technology basis as BAT, as well as the date those limits apply (see Section VII of the preamble for details on EPA's selection of BAT for the final rule). Section 4 of the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001) (Supplemental TDD) describes information that EPA evaluated with respect to the availability of the various technologies under consideration, including thermal technologies. Section VII of the preamble describes EPA's rationale for the final rule, including why it did not establish limitations based on thermal treatment.

EPA agrees with commenters who asserted that a softening pretreatment step is not always needed prior to the brine concentrator system depending on the influent water quality and the desired product, solids or brine. As described in Section 7.1.4 of the 2015 rule TDD, thermal treatment systems usually include pretreatment to remove calcium and magnesium salts, but not always. Page 64627 of the 2019 proposed rule preamble, referenced by commenters, only characterizes the state of current wastewater treatment systems in use in the steam electric industry, and does not provide a comprehensive list of all brine concentrator (or falling film evaporator) configuration possibilities.

As described in the preamble, EPA updated its cost estimates for thermal treatment technologies (evaporation) and found that the technology is 1.04 times more expensive than membrane filtration on an annual basis. EPA did not base any effluent limitations on thermal evaporation (see section VII.B.1 of the preamble). EPA notes that the final rule does not preclude the use of any specific technology(ies) or require that specific technology(ies) must be used.

EPA received no new information on the operation and maintenance challenges of thermal treatment technologies since the 2015 rule. EPA did not establish BAT limitations based on thermal treatment, as explained in Section VII of the preamble. Multiple commenters raise issues, specific to thermal treatment, that were addressed in the 2015 rule. As the commenter acknowledges, EPA responded to these comments in the 2015 rule (see DCN EPA-HQ-OW-

2009-0819-6469). As no new information has been obtained by or provided to the Agency, EPA refers to previous comment responses for additional details on the following topics.

- Regarding the commenter's statements on the corrosive nature of FGD wastewater, maintenance of scrubber blowdown consistency, and maintenance of a thermal crystallizer, see responses to comments in code 11.a (FGD Vapor Compression Evaporation – Demonstration/Performance) of the 2015 rule (in particular, see response to DCN EPA-HQ-OW-2009-0819-4655, Excerpt Number 108).
- EPA estimated non-water quality environmental impacts (NWQEIs), including electricity usage by thermal treatment systems, as part of the 2015 rule, and has not received any information that would change the results of the analysis. As such, the Agency expects that the energy requirements of the systems described in the *Flue Gas Desulfurization Thermal Evaporation Cost Methodology* memorandum (DCN SE08631) would be similar to the energy requirements estimated as part of the 2015 rule. Regarding the commenter's statement about thermal technology's parasitic load, see response to DCN EPA-HQ-OW-2009-0819-4379-A1, Excerpt Number 74 in Comment Code 11.b (FGD Vapor Compression Evaporation – Costs).
- . The type and amount of pretreatment varies based on the technology (e.g., spray dryers require less pretreatment than brine concentrators). Where softening or chemical precipitation is required for a particular thermal evaporation technology, EPA expects chemical requirements to be similar to those discussed as part of the 2015 rule, see response to DCN EPA-HQ-OW-2009-0819-4489-A1 Excerpt Number 18 in Comment Code 11.a (FGD Vapor Compression Evaporation – Demonstration/Performance) for a discussion on chemical requirements. The same can be said for the amount of sludge generated by thermal evaporation systems. As described in the *Flue Gas Desulfurization Thermal Evaporation Cost Methodology* memorandum (DCN SE08631), EPA updated its estimated costs for thermal evaporation, including updated costing information as well as updating the overall methodology to include data from several different vendors. While each individual vendor claimed cost data as confidential business information (CBI), EPA aggregated cost data to generate a single non-CBI cost curve. This cost curve represents several different types of thermal evaporation systems, including brine concentration and encapsulation through solidification process, crystallization, spray dryer evaporation, and direct contact evaporation. EPA'scost methodology accounts for the cost of additional chemicals, costs for hauling and transporting sludge, and purchasing of electricity to operate the thermal evaporation system as part of O&M costs. As presented in the *Flue Gas Desulfurization Thermal Evaporation Cost Methodology* memorandum (DCN SE08631), the O&M costs for thermal evaporation are higher than for any other FGD wastewater treatment technology evaluated by EPA.

EPA disagrees with the commenter who asserted that "The record thus shows that 'elimination [of FGD wastewater] is technologically and economically achievable' and that "in this circumstance, the Clean Water Act unambiguously requires EPA to impose a zero-discharge standard." As described in section VII.B.1 of the preamble, EPA is not establishing BAT limitations that would require zero liquid discharge (ZLD). As described in Section 4 of the Supplemental TDD, EPA agrees that some plants are utilizing treatment technologies to achieve

ZLD of FGD wastewater. However, as described in the final rule preamble, EPA has concluded that ZLD is not feasible at all plants. EPA agrees with commenters who asserted that evaporation impoundments are only feasible at specific plants and that not all plants may be able to utilize deepwell injection as a disposal method due to location and availability of existing wells, and constraints on drilling new wells.[58] For this cost estimate, EPA assumed that plants would utilize an existing commercial injection well rather than drill new wells onsite. EPA does not have the data to evaluate whether or not the primary deterrent for deepwell injection disposal is securing permits, geology, or other factors.

EPA agrees with the commenters who asserted that thermal technology is available. EPA identified four plants operating FGD wastewater treatment systems utilizing brine concentrators (a type of thermal evaporation) (see *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule* memorandum (DCN SE08688)). However, EPA did not select thermal evaporation as BAT due to total costs to industry and non-water quality environmental impacts, see section VII.B.I of the preamble for EPA's rationale for not selecting thermal evaporation.

EPA agrees that spray dryer technology can achieve zero discharge of FGD wastewater (see Appendices F and J of the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater* memorandum (DCN SE09213)). However, some plants are unable to use this type of system efficiently because it uses heat from the flue gas to evaporate wastewater, and there are limitations on where this type of system can be used most efficiently. This technology is typically only capable of treating smaller amounts of FGD wastewater (up to 216,000 gallons per day) due to the amount of flue gas that needs to be bypassed around an air preheater as well as boiler efficiency. EPA generally agrees with the commenter's statements that "flow minimization is always a good idea" as flow minimization can typically reduce the needed size of more complex treatment systems downstream. However, EPA also recognizes that other factors, such as materials of construction, water balance requirements, or water chemistry may limit the amount of flow minimization that can be achieved. EPA estimated flow minimization based on available data in its cost estimates for FGD wastewater (*see Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings* (DCN SE08630)).

Cost Estimates

EPA disagrees with commenters who asserted that the cost of thermal evaporation is comparable to membrane filtration. For the final rule, EPA estimated costs associated with thermal evaporation. See the *Flue Gas Desulfurization Thermal Evaporation Cost Methodology* memorandum (DCN SE08631) for a description of the costs estimated for thermal evaporation. EPA aggregated cost data for the following treatment technologies: brine concentrator with solidification, crystallization, direct contact evaporation system, and spray dryer evaporator.

[58] For the final rule, EPA has estimated costs for three brine management alternatives, one of which is based on plants using membrane filtration to concentrate wastewater and dispose of the brine via deepwell injection (see the *Flue Gas Desulfurization Membrane Filtration with Deepwell Injection Cost Methodology* memorandum (DCN SE08627)).

Although the estimates for thermal evaporation costs have changed since 2015 as described previously in this comment response, EPA continues to find that thermal evaporation costs are more expensive than other treatment technologies, including membrane filtration with solidification. See section VII of the preamble for EPA's rational for not selecting thermal evaporation as the BAT technology basis for the final limitations.

19 BATW – General

This response summary includes EPA's response to all public comments categorized as Code 19 (Bottom Ash Transport Water – General). See Part 1 of this document for a list of Code 19 excerpts. EPA's response covers the following subtopics:

- Support for the revisions to bottom ash (BA) best available technology economically achievable (BAT) and pretreatment standards for existing sources (PSES).
- High recycle rate systems as the BAT technology basis.
- Bottom ash transport water applicability dates.
- Mechanical drag system (MDS) quench water is not bottom ash transport water.
- Pollutant loadings and removals estimates.

Support for revisions to BA BAT and PSES

EPA acknowledges commenters' support for the final rule. EPA is finalizing a rule similar to the proposal, including the same technology bases for bottom ash transport water with revisions to the specific limitations and to individual subcategories. See section VII of the preamble for a summary of the final rule.

High Recycle Rate Systems as the BAT Technology Basis

EPA selected high recycle rate systems with a site-specific volumetric purge which cannot exceed 10 percent of the bottom ash transport water system volume per day on a 30-day rolling average as the technology basis for establishing the BAT requirements to control pollutants discharged in bottom ash transport water. EPA determined that this technology is available and economically achievable after evaluating the factors specified in CWA section 304(b)(2)(B). For bottom ash purge water, there are numeric best practicable control technology currently available (BPT) limitations equal to previously established BPT limitations on bottom ash transport water, leaving BAT limitations to be established on a case-by-case basis by the permitting authority using best professional judgement (BPJ). See section VII.B.2 of the preamble additional detail on why EPA selected high recycle rate (HRR) as BAT.

EPA agrees with commenters who stated that the record supports high recycle rate systems as the BAT basis for bottom ash transport water. Some commenters asserted that a volumetric purge allowance is unnecessary and would reward underperforming facilities and their operators with additional flexibility and compliance time. EPA disagrees and is finalizing the high recycle rate technology as BAT. As described in the preamble, when EPA finalized the "no discharge" BAT requirement in the 2015 rule, the Agency assumed that "closed-loop" systems would achieve zero discharge. Following the 2015 rule, EPA was informed that while some facilities with wet bottom ash systems can operate as zero discharge systems, most systems require some discharges to manage maintenance issues,[59] water imbalances,[60] and water chemistry imbalances including acidity and corrosiveness, scaling, and fines build-up. While some plants may be able to control or eliminate these challenges with relatively straightforward steps, others will require more extensive process changes and associated increased costs or find them difficult to resolve, however, EPA has learned that these problems could be mitigated or even avoided by purging the system from time to time.

who asserted that the cost effectiveness values for closed loop should be the basis for rejecting closed loop and EPA did not reject zero discharge on this basis. For the final rule, EPA estimated costs to treat a bottom ash transport water purge stream using a high-pressure reverse osmosis (RO) system to remove dissolved solids and facilitate complying with a zero discharge standard established by the 2015 rule (i.e., baseline). While EPA determined it is not likely that all facilities would incur these additional costs, EPA had no means to predict which plants would ultimately incur these additional costs, and thus EPA reasonably assumed, for purposes of its economic achievability analysis, that each facility would incur these costs in order to ensure that the costs upon which economic achievability are based are not underestimated.

As described in section VII.B.2 of the preamble, EPA notes that closed-loop systems cost more than high recycle rate systems for treatment of bottom ash transport water. While EPA does not find the estimated additional cost to industry would result in plant closures, cost is a statutory factor that EPA must consider under section 304(b) of the CWA, and EPA has discretion in weighing the statutory factors. EPA views the higher cost of fully closed-loop systems as an additional factor supporting EPA's decision to reject closed-loop systems as BAT for treating bottom ash transport water.

Bottom Ash Transport Water Applicability Date

For the final rule, the bottom ash transport water BAT limitations based on high recycle rate systems do not apply until a date determined by the NPDES permitting authority that is as soon as possible beginning one year following publication of the rule, but no later than December 31, 2025. As described in the preamble and the comment response to code 33, EPA determined that extending the "no later than" date for compliance with the bottom ash transport water

[59] The 2015 rule maintenance discharges were characterized as not a significant portion of the system volume, compared to, for example, potential discharges resulting from maintenance of the remote MDS tank or the conveyor itself. Such maintenance could require draining the entire system, which would not be permissible under the 2015 rule maintenance discharge allowance.

[60] The 2015 rule provided no exemption or allowance for discharges due to precipitation events. While systems are often engineered with extra capacity to handle rainfall/runoff from a certain size precipitation event, these events may occur back-to-back, or facilities may receive events with higher rates of accumulation beyond what the facility was designed to handle.

requirements to December 31, 2025 allows companies time to analyze the final rule, plan, and construct any necessary treatment system upgrades under COVID-19 construction protocols and harmonize their compliance strategy with requirements for FGD wastewater and the CCR Part A rule.

Some commenters asserted that a compliance deadline of 2023 for bottom ash transport water does not provide sufficient time to conduct a BPJ analysis for bottom ash purge water and install any appropriate technology. EPA acknowledges the concern but encourages permittees to work proactively with their permitting authority to provide all information to support timely processing of the permit. EPA strongly encourages state and tribal permitting authorities to invest the time and resources necessary to establish BPJ limits for BA purge water and issue permits timely to allow plants to install the necessary equipment within compliance deadlines in the final rule. EPA can provide technical support to permitting authorities evaluating technologies under BPJ and has provided some general principles in the preamble of the proposed rule to guide permitting authorities (see Section XIV.A.2 of the preamble).

MDS Quench Water is not Bottom Ash Transport Water

Some commenters requested that EPA clarify that MDS quench bath water is a low volume waste, not bottom ash transport water, and requested EPA revise the definition of “low volume waste” accordingly. The final rule preamble and the Supplemental TDD clarify that MDS quench bath water is not bottom ash transport water, but rather should be managed as low volume waste. See Appendix A of the final rule preamble (defined terms for purposes of the preamble) and Section 4.2 of the Supplemental TDD. EPA disagrees that the definition of low volume waste needs to be revised to specifically include MDS quench water. The definition of transport water in the final rule regulatory text and the Supplemental TDD clearly state that MDS quench water is not bottom ash transport water.

Pollutant Loadings and Removals Estimates

Some commenters asserted that EPA overestimated pollutant loadings associated with discharges of bottom ash transport water and that the Agency should adjust the estimated pollutant loadings or pollutant reductions based on possible source water contributions. EPA disagrees with these comments, as it did with similar comments received on the 2015 rule.

In order to adjust the pollutant loadings based on possible source water contributions, EPA would need paired data comparing source water pollutant concentrations to treated effluent pollutant concentrations for a range of process streams, facilities, and facility locations. EPA does not have these data for the plants subject to this final rule and therefore cannot make these calculations. While some did provide relevant data for some specific plants, it cannot be used to characterize source water for plants at different locations because concentrations of pollutants in source water can vary considerably from one waterbody to the next and even within the same waterbody. EPA notes that 40 CFR Part 122.45(g) allows facilities to request, on a case-by-case basis, a specific permit adjustment to an effluent standard based on the presence of a pollutant in their influent.

As part of public comment, the Electric Power Research Institute (EPRI) submitted, and other commenters supported, its methodology for estimating bottom ash transport water loadings (Appendix H of EPA-HQ-OW-2009-0819-8293) which are used as basis for comparison in the organization's comments. EPA disagrees that EPRI's analysis is an accurate assessment of bottom ash transport water loadings for the following reasons:

- EPRI's analysis for estimating pollutant loadings in bottom ash transport water includes two sets of water quality data: one for "single-pass" systems and one for a "10% allowable purge" system.
    - EPRI's single-pass analytical data set includes samples from more than 15 facilities that do not meet all of EPA's data acceptance criteria, discussed in DCN SE07208, and were determined to be inappropriate (and, therefore, excluded) for characterization of bottom ash transport water effluent. EPRI's analysis includes settled bottom ash sluice samples that the industry, itself, found to "greatly overestimate the pollutant loadings attributable to bottom ash pond effluent" and were excluded from EPA's analysis (see DCN SE05597).
    - EPRI's 10% allowable purge analytical data set includes samples from 2016 and 2019 EPRI reports submitted to EPA as confidential business information in May 2020 (after the comment period closed and after EPA completed its analytical data set for bottom ash transport water effluent). EPA conducted an abbreviated evaluation of these data and determined these data did not meet the Agency's acceptance criteria.
    - See the "Development of the Bottom Ash Transport Water Analytical Dataset and Calculation of Pollutant Loadings for the Steam Electric Effluent Guidelines Proposed Rule – DCN SE07208" memo for additional information on the Agency's acceptance criteria and data used to characterize bottom ash transport water for the final rule.
- EPRI's pollutant loadings estimates only include a subset of pollutants included in the Agency's analysis.
- EPRI's analysis calculated the net bottom ash discharge by subtracting out the source water concentration from the bottom ash transport water concentration. EPA did not adjust pollutant loadings based on source water data for reasons described above.
- Unlike EPA's analysis, which estimates unit-specific loadings based on facility-reported flow data, EPRI's analysis estimates pollutant loadings and removals based on a single flow rate for single-pass systems and 10% allowable purge systems for the entire industry. The commenter did not provide an explanation for how the flow rate was developed and, therefore, the Agency is unable to determine whether it is reasonable.

For these reasons, EPA determined that the results of EPRI's analysis are not directly comparable to the pollutant loading estimates developed for the proposal rule or final rule. See section 6 of the Supplemental TDD for discussion of EPA's approach for estimating pollutant loadings and effluent reductions in pounds per year for baseline and the evaluated regulatory options.

Some commenters asserted that the Agency has significantly weakened the 2015 rule by allowing utilities to continue to discharge bottom ash transport water. EPA disagrees. As described previously in this response, EPA's decision to change the BAT technology basis for bottom ash transport water is supported by process challenges that have been identified with closed-loop systems. As also described in the preamble, many facilities that EPA previously modeled as "zero discharge" for the 2015 rule would, in fact, require routine discharges to maintain system, water and chemistry balance at the plant. For the final rule, EPA's analysis supporting the final rule's high recycle rate systems assumes all affected facilities will discharge the maximum allowable 10 percent bottom ash purge water on a rolling 30-day basis. Because the final rule establishes a 10 percent maximum purge rate, and the actual purge rate will be established by the permitting authority based on best professional judgment, EPA's analysis likely overestimates pollutant discharges associated with the BAT for bottom ash transport water. To the extent that necessary purges are smaller than this 10 percent, EPA evaluated the estimated compliance costs and pollutant loadings as an alternate scenario based on a 2 percent purge rate (DCN SE09073). These analyses would not change EPA's conclusion that high recycle rate systems, rather than closed-loop systems, are BAT.

The Agency also estimates small environmental and ecological changes associated with changes in pollutant loadings as compared to the 2015 rule, including small changes in impacts to wildlife and humans. See the Supplemental EA Report and response to Code 27 (Environmental Assessment - General Impacts & Exposure Pathways) for more information on environmental impacts associated with pollutants present in bottom ash transport water and incremental change in environmental impacts under the final rule.

20 <u>BATW – Data</u>

Some commenters asserted that the bottom ash transport water bromide mass loadings estimates included in EPA's analyses in support of the proposed rule are based on "inadequate" or "questionable" analytical data. These commenters also assert that these data are not representative of bottom ash transport water effluent concentrations across the industry because of alleged "high variability among a small set of sites" or because "two of the four power plants have either retired or retrofitted dry ash handling." EPA disagrees with these comments.

As discussed in the "Development of the Bottom Ash Transport Water Analytical Dataset and Calculation of Pollutant Loadings for the Steam Electric Effluent Guidelines Proposed Rule – DCN SE07208" memo, EPA evaluated bottom ash transport water effluent sampling data using defined acceptance criteria to compile the analytical dataset included in EPA's Bottom Ash Transport Water Pollutant Loadings Database (DCN SE08966). EPA determined that the ten bromide samples included in the loadings analyses met all of the listed acceptance criteria and were appropriate for characterization of bottom ash transport water effluent. EPA also determined that 20 bromide samples from eight plants were not appropriate for characterization of bottom ash transport water effluent because the samples were not analyzed with approved methods, the samples were not representative of bottom ash transport water (i.e., not composed of at least 75 percent bottom ash transport water), and/or the samples did not represent actual bottom ash impoundment effluent. EPA did not receive comments on its defined acceptance criteria and did not receive any additional bottom ash transport water effluent bromides sampling data from commenters or from industry stakeholders despite multiple opportunities to submit such information.

EPA also reviewed bottom ash bromides data from an EPRI report, see Guidance Document for Management of Closed-Loop Bottom Ash Handling Water in Compliance with the 2015 Effluent Limitations Guidelines (DCN SE06963). EPA did not include any data from this report in its analytical dataset because it did not meet all of EPA's acceptance criteria (DCN SE07208).

EPA also disagrees that bromide analytical data collected from facilities that have either retired or retrofitted dry ash handling systems is invalid. The fact that facilities have retired or retrofitted since the sample collection does not impact the representativeness of the samples at the time of collection. EPRI's own calculations of bottom ash transport water concentrations, described in Appendix H of EPA-HQ-OW-2009-0819-8293, includes analytical data for several plants that have retired, repowered, or converted to dry bottom ash handling since sampling.

21 BATW – High Recycle Rate

No comment excerpts were received on this topic.

21a BATW – High Recycle Rate – Purge Basis, Provisions, and Regulatory Language

Rationale for Authorizing a Specified Amount of Purge in an NPDES permits

EPA disagrees with commenters who suggested that a volumetric purge limitation is not warranted. EPA is authorized to look across the category as a whole when determining BAT and is required to consider the factors upon which this limitation is based, specifically process changes (*see, e.g., Cooling Water Intake Structures Coalition et al. v. U.S. EPA*, 905 F.3d 49, 67 (2nd Cir. 2018) (Upholding EPAs rejection of an option based on space constraints being a problem for a subset of the industry.) Since EPA understands these comments as suggesting an alternative BAT was warranted, see EPA's rationale for selecting high recycle rate systems in section VII.B.2 of the preamble. The same is true with respect to suggestions relating to thermal treatment for the purge; however, to the extent the commenters are suggesting that this technology might be warranted for treatment of the purge, EPA acknowledges that thermal treatment would likely be part of a permitting authority's BPJ analysis for BA purge water. Further discussion of BPJ is presented in comment code 4 (Regulatory Options – BPJ).

EPA disagrees with commenters who asserted that the volumetric approach as a percent of system volume is inappropriate and would incentivize the construction of overly large treatment systems to allow for higher purges. In several places in the regulatory text, EPA requires the management of BA transport water in installed equipment to the extent feasible (e.g., temporarily holding water in an existing maintenance tank rather than discharging), and the construction of larger tank systems would provide additional volume with which to manage various inflows that might otherwise result in a discharge. Instead, plants are more likely to minimize the footprint of any system to minimize costs.

EPA also disagrees with commenter's belief that EPA should not have relied on the data present in the EPRI (2016) and EPRI (2018) reports and instead should have done an independent data collection to establish the purge volume. First, to the extent that commenters discuss the "best performing plant," EPA notes that it is the selection of BAT that is done with reference to the "best" performing plant, and that the term "best" is not limited to one meaning, and is defined by the statute as what is technologically available and economically achievable in light of the statutory factors specified in Clean Water Act section 304(b). *See BP Exploration, et al v. EPA*, 66 F.3d 784, 796, 800 (6th Cir. 1995) (In upholding EPA's rejection of reinjection based on total industry cost, the court said, "[t]he CWA's requirement that EPA choose the 'best' technology does not mean that the chosen technology must be the absolute best. Obviously, BAT and NSPS must be acceptable on the basis of numerous factors, only one of which is pollution control."). *See also Entergy Corp. v. Riverkeeper, Inc*., 556 U.S. 208, 218 (2009) (stating that the term "best" in section 316(b) does not necessarily refer to the one that produces the most of some good (e.g., reduction in adverse environmental impact)). Once BAT is selected, EPA develops limitations which that technology can reasonably achieve. Here, EPA has determined that high recycle rate systems are BAT, and the question for EPA given this selection is: What limitations can a high recycle rate system reasonably and consistently meet? Here EPA used available purge data from a set of well-studied high recycle rate systems to determine what volumetric purge a high recycle rate system can meet. While EPA can always collect more data, at some point data collection must cease, and a final rule be issued. *See Kennecott v. EPA*, 780 F.2d 445, 451 (4th Cir. 1985) ("The number of data points here is not insignificant, and there must exist some reasonable termination point in the process of data collection."). For BA transport water, EPA finds that this data is adequate to characterize the variability in the amount of purge required. EPA also disagrees that this data represents the worst performing plants. EPA discussed the need for purge in meetings with many electric utilities, and numerous examples were given both in those meetings, and in comments on the proposed rule. As EPA states in Section VII.B.2 of the final rule preamble:

> "Some commenters argued that the proposed BAT based on high recycle rate systems is not warranted because that technology basis does not represent what is achieved by the single best performing plant, and even went so far as to say that this standard reflected the worst performing plant. EPA disagrees with these commenters. Some companies began proactive fleetwide conversions either before the effective dates of the 2015 rule or in some cases before the 2015 rule was signed. Many of these fleetwide conversions were to the remote MDS, a specific type of high recycle rate system that formed the "closed-loop" part of the 2015 rule BA transport water BAT technology basis. As discussed above, these systems do not all operate 100 percent closed-loop, as EPA assumed they

> did when finalizing the 2015 rule. Based on actual, measured purge rates in EPRI (2016), however, the Agency estimates that actual purge rates necessary on a day-to-day basis may be less than one percent of the system's volume, with higher purges necessary at less frequent intervals due to precipitation and maintenance. Furthermore, while surface impoundments can cover dozens of acres and contain volumes in the billions of gallons, typical high recycle rate systems have volumes closer to one-half million gallons (1/2 million). Thus, even assuming the proposed maximum allowable purge of 10 percent is necessary for a unit, the average gallons per day released by high recycle rate systems will be two percent of the average gallons per day released by surface impoundments, and therefore will also be 1.5 percent of the pollutant releases expected from surface impoundments. Industry-wide, EPA estimates this combination of reduced volume and increased recycling reduces discharges by 366 million pounds of pollutants per year, and thus makes reasonable further progress toward the CWA goal to eliminate the discharge of pollutants. *See* 33 U.S.C. 1251(a), 1311(b)(2)(A). Therefore, it is the combination of the reduced system volume and high capacity to recycle BA transport water that supports EPA's basis for high recycle rate systems as BAT."

In short, EPA disagrees with commenters who assert no purge is necessary in the final rule and agrees with the commenters who provided support for a volumetric purge, especially where such commenters provided examples of challenges faced by specific plants. Based on these comments, EPA concludes that the challenges and purges provided in the EPRI reports are sufficiently representative of problems presented across the industry, and the purge limitations in this final rule are reasonable to capture the variability of these purges.

Calculation of Limitations

With respect to comments that EPA's purge limitations are arbitrary, Section XII.B details the information and calculations used to estimate the 10 percent purge limitations. EPA disagrees that the maximum 10 percent volumetric standard is arbitrary. EPA notes that the 10 percent limitation operates as a cap, and permitting authorities are required to develop a site-specific purge based on site-specific information. Thus, even assuming a fixed 10 percent purge might not match the need at all plants, the ability of permitting authorities to tailor this purge will help ensure that the amount of discharge allowed at each site will reflect what is necessary and appropriate for each plant, but in no case will exceed the 10 percent cap.

With respect to comments on the selection of 10 percent, EPA agrees in part with comments providing support for the purge, but also agrees in part with comments suggesting that smaller purges are possible. EPA developed the 10 percent purge limitation after analysis of actual purge data as discussed in section XIII.B of the preamble, and the site-specific determination of a purge not to exceed that 10 percent allows each permitting authority to tailor the amount of purge necessary and appropriate based on facts specific to each site. To the extent that the regulatory text provides that plants employ "additional control measures," EPA believes that this language provides a useful tool to assist permitting authorities as they determine the necessary purge amount. For example, one plant reported that it was able to address acidity in its high recycle rate system by decreasing the flow of the system and increasing the contact time with the BA. Such actions complement the existing four conditions under which a discharge may be authorized.[61]

EPA disagrees with commenters who assert that power plants may be required to purge more than 10 percent of the system volume. EPA does not have data or any examples of a high recycle rate system where a purge of greater than 10 percent of its volume is required on a regular basis. EPA recognizes that some dischargers, including those that are currently operating technologies representing the technology basis for the final rule, may need to improve their treatment systems, process controls, and/or treatment system operations in order to consistently meet the final effluent limitations and pretreatment standards. This is consistent with the CWA, which requires that BAT/PSES discharge limitations and standards reflect the best available technology economically achievable.

Commenter's concerns about equipment failures do not indicate that higher purge limitations are necessary. EPA requires in the final regulatory text that equipment be "properly installed, operated, and maintained" and it is unclear why such properly maintained equipment would unexpectedly fail to the extent described in comments. Even if there were an "upset" to the system, the plant would have an affirmative defense to an enforcement action if the requirements of 40 CFR 122.41(n) are met.

Similarly, concerns about high precipitation events and natural disasters do not indicate that higher purge limitations are necessary. In response to comments, EPA analyzed the two real-world rainfall scenarios presented by commenters, assuming an exposed surface of 28,533 square feet[62] and using the following three statistical storm events:[63]

- 10-year, 30-day (representative of the duration for calculating the rolling daily average of the proposed 10% purge; lower bound of real-world Tennessee valley scenario presented by commenters)
- 25-year, 30-day (representative of the duration for calculating the rolling daily average of the proposed 10% purge; upper bound of real-world Tennessee valley scenario presented by commenters)
- 1,000-year, 72-hour (representative of real-world Hurricane Florence scenario presented by commenters)

[61] See 40 CFR 423.13(k)(2)(A)(I)-(IV) and 40 CFR 423.16(g)(2)(i)(a)(I)-(IV).
[62] This area is based on 2x100% redundant RMDS troughs each with exposed surface area (including captured runoff) of 14,266 square feet. UWAG assumed three troughs with 42,800 square feet of surface area including the immediate area surrounding the troughs and one or more clarifiers with 25,500 square feet of surface area. Clarifiers are not part of the BAT technology basis. Thus, EPA did not include clarifier area here. While EPA typically costs a system with a single shared RMDS trough as the least-cost option, in some meetings with utilities, staff indicated that 2x100% redundant RMDS troughs had been installed where power plants need to ensure low downtime.
[63] Precipitation data used by EPA is available online at: *https://hdsc.nws.noaa.gov/hdsc/pfds/pfds_map_cont.html?bkmrk=nc*

As seen in Table 1 below, both of the 30-day inflows and the extreme 1,000-year, 72-hour inflow can drastically increase the potential need for precipitation-related purges; however, these large volumes are still less than the average remote MDS volume.[64] Because these significant inflows are rare, there is a low probability that many power plants would experience more than one or two storm events of this level during the useful life of the equipment (by definition, even a 25-year event may not occur during the expected 20-year operating life of the bottom ash equipment).[65] Thus, even though larger volumes could be discharged during these rare events, the overall volumetric cap of 10 percent of system volume would still be achievable. Even if there were an "upset" to the system that would exceed the 30-day rolling average, the plant may have an affirmative defense to an enforcement action if the requirements of 40 CFR 122.41(n) are met. EPA concludes that no additional discharge allowance is necessary, and further notes that if precipitation discharges were carved out of the purge limitations, the purge limitations would likely be reduced.

Table 1. Comparison of Accumulated Precipitation Volumes (Gallons)

Precipitation Event	Scenario	Real-World Rainfall Events	
	Plant	**Gallatin**	**Sutton[66]**
	Met. Site	*Gallatin, TN*	*Wilmington, NC*
10-year	**30-day**	249,000	-
25-year	**30-day**	283,000	-
1,000-year	**72-hour**	-	418,000

Note: Estimates are rounded to three significant figures.

With respect to comments suggesting site-specific purge rates and BMP plans, EPA agrees in part. The final rule only establishes a cap of 10 percent of system volume. Permitting authorities will ultimately determine the amount of purge that is allowed under this cap. Thus, the final rule is, in part, site-specific. However, EPA disagrees to the extent that commenters asked EPA to establish parallel regulations where a plant could choose to do or not do the site-specific alternative. This would be overly burdensome to the permitting authority, and in any case these requests were mostly in the context of power plants asking to discharge more than 10 percent.[67] EPA has analyzed the record and determined that a cap of 10 percent purge, calculated as a

[64] The average RMDS that EPA has information on has a volume over 500,000 gallons.

[65] Some commenters suggested that the frequency of such events may be increasing; however, since EPA already allows for discharge associated with these events, the permittee should ensure that consideration of this increasing frequency be included in the reporting of 423.19(c).

[66] Sutton retired in 2013 and is only presented here to represent the impacts that Hurricane Florence had on a most-impacted location.

[67] Some comments misunderstood the 10 percent purge and asked EPA to allow for higher purges at lower frequencies. The 10 percent purge in the final rule is a 30-day rolling average. Thus, to the extent that discharges are infrequent, a power plant could discharge much higher than 10 percent of the system volume in a single day and still meet the rolling average.

rolling average, is achievable by the high recycle rate system BAT technology basis (see Section XIII.B of the preamble for further discussion).

Finally, EPA rejects the idea that 100 percent of BA transport water should be purged. With respect to comments that leachate concentrations do not exceed drinking water standards, these comments are beyond the scope of this rulemaking. Furthermore, with respect to any consideration of pollutant concentrations in establishing either BAT or the applicable limitations, the *SWEPCO* Court clearly distinguished BPT (which calls for a comparison of costs to effluent reduction benefits) from BAT (which does not). *See Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999, 1027 (5th Cir. 2018) (holding that EPA's apparent benefit-weighing in that case to be inconsistent with the statute).

Operational Considerations for Limitations

With respect to quench water added to the boiler, EPA understands that some power plants may be able to recycle BA transport water back to the boiler to be used as quench water. To the extent that this water is recycled back into the system, it avoids discharge. With respect to other wastewaters captured in the BA transport water system (e.g. seal water), once these waters enter the recirculating system and are used to transport BA, they become BA transport water. Thus, no separate treatment is necessary.

With respect to the 30-day rolling average, EPA disagrees that this timeframe is inappropriate for BA transport water. Commenters argue that because precipitation-related and maintenance-related purges are rare, a 30-day period is too long. However, that is exactly the point. A rolling average provides a plant the flexibility to discharge larger volumes when such infrequent events occur, and smaller volumes the rest of the time. EPA has also provided additional guidance to permitting authorities in section XIV.A.2 of the preamble, and section 423.19(c) of the final rule requires reporting, which EPA believes will assist permitting authorities in determining the site-specific purge and treatment.

Conditions Under Which Discharge May be Authorized

With respect to the requirement to use equipment to manage potential discharges, EPA disagrees with commenters that this requirement is unnecessary or creates ambiguity. EPA believes that the language is clear in its meaning: plants must use equipment to reduce or eliminate the need for a discharge. To decide otherwise would be to allow plants which have already purchased and installed such equipment to decline to use it where it might reduce or eliminate purges. This would be inconsistent with the statutory requirement that EPA select the best available technology economically achievable. Only after EPA establishes BAT and the corresponding limitations would a plant have limitations that could be bypassed. Furthermore, because these discharges must be reduced or eliminated using installed equipment as discussed above, EPA disagrees that a blanket approval of any incidental discharges is warranted.

With respect to specific changes suggested for the condition to discharge to maintain water balance from precipitation related inflows, EPA has modified the text of this condition to read "…from storm events exceeding a 10-year storm event of 24-hour or longer duration (e.g., 30-day storm event)…" This revised language makes clear that discharges for longer-term events are permissible as requested by commenters, though it incorporates these longer-term events through explicit reference to the storm event duration rather than forcing plants to evaluate whether storm events were "equivalent to" some specified event as commenters had recommended. Furthermore, by using a 10-year, 24-hour minimum storm event, the final rule is consistent with requirements for coal pile runoff,[68] and to the extent that coal pile runoff is comingled with BA transport water at some plants, this allows plants to design for, and implement, a single standard.[69]

EPA disagrees that the specific changes suggested for the condition to discharge to maintain water balance are warranted. Specifying that discharges are allowed "consistent with system design" does not assure that these discharges are necessary. While there may be instances where plant-wide piping of non-BA wastestreams to the high recycle rate system cannot be feasibly changed (e.g., digging up all subsurface piping), there may be other instances where a segregated alternative is straight forward and relatively convenient (e.g., redirecting a coal mill rejects sump to the low volume wastewater treatment system instead of the BA system). EPA need not definitively determine where, or with what prevalence comingling of wastestreams is necessary here. Instead, the final rule allows the permitting authority to determine the appropriate purge based on site-specific information.

With respect to specific changes suggested for the condition to discharge to maintain water chemistry, EPA agrees with commenters and has made the recommended changes to ensure that the description would not inadvertently exclude items the Agency intended to cover.

With respect to specific changes suggested for the condition to discharge for other maintenance events, EPA agrees with commenters. The proposed rule language was ambiguous, and the final rule now defines this maintenance condition through exclusion of the three other discharge conditions and exclusion of the 2015 rule's existing maintenance exemption in the definition of "transport water." Thus, any maintenance discharge not otherwise covered could now satisfy this condition.

21b <u>BATW – High Recycle Rate – Costs and Loads</u>

Under the final rule, EPA selected high recycle rate (HRR) systems with a site-specific volumetric purge (not to exceed 10 percent of the system volume) as the technology basis for establishing the Best Available Technology Economically Achievable (BAT) requirements to

[68] *See* 40 CFR 423.12(b)(10).

[69] Commenters correctly pointed out that EPA failed to account for costs to manage stormwater at proposal. The final rule cost estimates include the costs for buildings to house the bottom ash systems which would prevent the majority of precipitation-related inflows, and therefore discharges.

control pollutants discharged in bottom ash (BA) transport water, see section VII.B.2 of the preamble for more information.

Some commenters asserted that the Agency underestimated compliance costs associated with BA transport water requirements of the final rule. EPA received public comments on its BA compliance cost methodology, and one commenter specifically submitted industry-level compliance cost estimates for mechanical drag system (MDS) and remote MDS retrofits. These estimates serve as the basis for the commenters' comparisons to the Agency's proposed rule cost estimates.

EPA reviewed the commenters' BA cost estimates and underlying methodology (EPA-HQ-OW-2009-0819-8293). EPA cannot fully evaluate or provide a detailed response to the MDS and remote MDS cost estimates and methodology because the commenters failed to provide documentation of how they arrived at actual costs or sufficient information on how they were calculated. However, the Agency identified notable differences in the analysis, as described below.

- The commenters' remote MDS costs estimates are based on total engineering, procurement, and construction (EPC) cost for ten steam electric power plants, which were normalized on a dollar-per-remote MDS basis and then applied to the costed population. The commenter does not identify the ten plants nor does it provide any plant-specific or aggregated information used to estimate the average remote MDS unit cost or the estimated average remote MDS cost (e.g., BA generation rate, electric generating unit capacity, BA sluice flow).
- EPA also notes the following regarding the commenter's remote MDS cost estimates:
    - Remote MDS retrofits. EPA's cost estimates are based on one remote MDS being installed for every electric generating unit at the plants identified as requiring a conversion and where remote MDS was identified as the least-cost technology. In contrast, the commenter estimated that plants with multiple electric generating units may be able to benefit from economies of scale and install fewer remote MDS units (e.g., three remote MDS to service five units) based on the specific needs and design of each facility. EPA did not account for remote MDS servicing multiple electric generating units as outlined by the commenter because plant-specific data (e.g., BA sluicing frequency, number and configuration of BA transport water lines) were not available to accurately determine the extent to which existing systems used shared or independent piping, nor the extent to which the BA sluice cycles can be adequately coordinated to enable the shared systems that would offer economies of scale.
    - Economizer ash. EPA is not requiring that economizer ash be handled with BA as part of this rule and, therefore, EPA did not account for economizer ash in its cost estimates. However, EPA acknowledges that some plants have historically chosen to manage economizer ash in their BA system, and that this may continue as plants transition away from surface impoundments under the CCR rule.

  - Polishing clarifiers. EPA did not include, nor did the commenter justify the need for, polishing clarifiers or lamella plates to meet the BAT requirements for BA transport water. EPA did, however, account for the costs of an underflow baffle and overflow weir for each system and costs associated with constructing a roof over the remote MDS and auxiliary equipment to mitigate stormwater entering the BA system.
  - Individual remote MDS and maintenance. EPA's cost estimates account for individual remote MDS and storage silos for each electric generating unit, piping, pumps, buildings, and chemical injection systems, should that become necessary to prevent scaling within the system. EPA also accounts for maintenance tank capacity during 5-year maintenance events and is aware that plants with multiple remote MDS installations use remote MDS units as additional surge tank capacity, if necessary. While it is not likely that all plants would require all of this equipment, EPA reasonably assumed that each facility would incur these costs for purposes of its economic achievability analysis.
- The commenter's MDS capital cost estimates are based on a cost curve; however, they did not provide any detail about how the equation was developed.

Subcategorization is not accounted for in the commenter's analysis. For the final rule, EPA determined that 30 electric generating units are expected to incur full BA system conversion costs to meet the BA requirements. In contrast, the commenter's industry-level BA cost estimates assume that 96 electric generating units will incur full BA system conversion costs (i.e., a conversion to MDS or remote MDS). EPA thinks the commenter overestimates the number of plants requiring a full BA system conversion because they do not account for two subcategories established in the final rule: one for electric generating units permanently ceasing coal combustion by 2028 and one for low utilization electric generating units (not subject to the BAT limitations based on HRR BA systems). The commenter also does not account for plants that already operate HRR systems (minor costs) or for changes in operation due to Part A of the Coal Combustion Residuals (CCR) rule.[70] These 77 electric generating units (in EPA's analyses) are expected to incur zero or only a portion of BA compliance costs compared to full conversions (see section 5 of the Supplemental TDD).

Based on the assumptions provided in the commenter's materials, EPA predicts that the commenter's total industry-level cost estimates are an overestimation of the BA transport water compliance costs for the final rule.

EPA disagrees with the commenter's assertion that it underestimates the cost of remote MDS by "not fully accounting for costs outside of the remote MDS equipment itself." As described in section 9 of the 2015 TDD and section 5 of the Supplemental TDD, EPA's cost estimates reflect fully erected and commissioned systems (including equipment, controls, foundations, and field labor) and account for the freight, installation, instrumentation and controls, piping, electrical, buildings, yard improvements, service facilities, and land as direct capital costs in addition to

[70] As described in section 5 of the TDD, EPA expects more than 30 plants to install a HRR BA system to comply with Part A of the CCR rule.

purchased equipment. EPA also accounts for engineering and supervision, construction expenses, contractor's fees, and contingency costs as indirect capital costs.[71] The BAT system has redundancies. For example, EPA anticipates that, under normal operating conditions, plants with at least two remote MDS units will direct BA transport water from electric generating units sequentially to one remote MDS at a time using other remote MDS units as a settling tank. See Section 5.2 of the Supplemental TDD for additional information about EPA's bottom ash cost methodology and BA system components (EPA-821-R-20-001). See the comment response to code 21a (BA Transport Water – HRR – Purge Basis, Provisions, & Regulation Language) for information on BA purge water provisions.

While plant-and unit-level costs may be over or underestimates, EPA's industry-level cost estimates are based on available and representative data, and they are a reasonable prediction of overall compliance costs to industry as a result of the final rule. EPA notes that, under the Clean Water Act, the Agency does not have to make a precise calculation of costs and its industry-level costs must be reasonable. See, e.g., *Chemical Mfrs. Ass'n v. EPA*, 870 F.2d 177, 237-38 (5th Cir. 1989); *Kennecott Copper v. EPA*, 612 F.2d 1232, 1238 (10th Cir. 1979); *BASF Wyandotte Corp. v. Costle*, 598 F.2d 637, 662 (1st Cir. 1979); *BP Exploration & Oil Inc. v. EPA*, 66 F.3d 784, 799-800 (6th Cir. 1995); *NRDC v. EPA*, 863 F.2d 1420, 1426 (9th Cir. 1988); *Weyerhaeuser v. Costle*, 590 F.2d 1011, 1045 (D.C. Cir. 1978). EPA notes that other industry commenters stated that the "costs estimated by EPA for the management of BA transport water are reasonably correct." In fact, multiple plant-specific capital cost and O&M cost estimates provided by one commenter are much lower than EPA's compliance costs to install the BAT technology at the same plants (see EPA-HQ-OW-2009-0819-8489).

EPA disagrees with commenters who asserted that the Agency should identify and estimate compliance costs for the "installed spares, redundancies, maintenance tanks, and other secondary bottom ash equipment" mentioned at section 423.13(k)(2)(i)(A)(I) and (III) of the proposed rule. As described in section XIV of the preamble, EPA finalized reporting and recordkeeping requirements for plants operating HRR BA systems. EPA is requiring that plants with HRR systems submit the calculation of the primary active wetted BA system volume, which means the maximum volumetric capacity of BA transport water in all non-redundant piping (including recirculation piping) and primary tanks (e.g., bins, troughs, clarifiers, and hoppers) of a wet BA system, excluding the volumes of surface impoundments, secondary BA system equipment (e.g., installed spares, redundancies, and maintenance tanks), and non-BA transport systems that may direct process water to the BA system. EPA is defining "primary active wetted BA system volume" to specifically exclude secondary BA system equipment (e.g., installed spares, redundancies, and maintenance tanks). EPA is aware that plants may install this secondary BA system equipment either voluntarily or as a result of the permitting authority's evaluation of the appropriate purge rate, but does not take the position that it is required or should be costed as part of the BAT system.

[71] EPA estimated that indirect capital costs account for approximately 43 percent of the total direct capital costs. EPA notes EPRI's plant engineering factor is only 3.5 percent applied to the vendor's EPC cost.

Commenters questioned EPA's assumptions about the volume of stormwater the BAT remote MDS would need to be sized to accommodate. For the final rule, EPA is making permissible discharges of BA transport water associated with precipitation-related inflows generated from storm events exceeding a 10-year, 24-hour or longer duration that cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment. See § 423.13(k)(2)(i)(A)(I) through (IV) for conditions under which the discharge of pollutants in BA transport water is authorized and EPA's response to code 21a for more information on EPA's evaluation of storm events. As described in section XIII of the preamble, EPA also accounted for precipitation- and maintenance-related discharges in development of the maximum 10 percent 30-day rolling average BA purge water rate. Further, for all electric generating units currently operating or expected to install a remote MDS to comply with the ELGs, EPA estimated capital costs associated with constructing an enclosure or roof over the remote MDS and auxiliary equipment to mitigate stormwater contributions to the BA system. See the "Methodology for Estimating Bottom Ash Transport Water Compliance Costs for the Final Revisions to the Steam Electric ELGs – DCN SE08505" memo for additional information.

As described in the preamble, EPA concluded that BAT limitations for any wastewater that is purged from a HRR system (BA purge water) and then discharged, should be established by the NPDES permitting authority on a case-by-case basis using Best Professional Judgement (BPJ). EPA concludes that permitting authorities are in a better position than EPA to examine site-specific climate and maintenance factors, especially since the permitting authority will already be determining the allowable volume of purge, up to a maximum of 10 percent of the system's volume. Permitting authorities will also be in a better position than EPA to account for site-specific treatment technologies and their configurations already installed or being installed to comply with the CCR rule and other regulations which could accommodate the volumes of, and successfully treat, any discharges of wastewater from a HRR system associated with the purge allowance. See the comment responses to comment codes 4 (Regulatory Options – BPJ) and 43 (Numeric Limitations) for additional information about establishing BAT limitations based on permitting authority BPJ.

EPA disagrees with one commenter who asserted that the BA cost estimates for the Cumberland, Gallatin, Kingston, and Shawnee plants are incorrect. The commenter asserts that the total cost for these four plants to "close the loop" is $108,000,000, but fails to identify the specific equipment or process changes that are needed or the basis for their cost estimate. The commenter does not provide sufficient information for EPA to have a record basis to adjust the costs for these plants. Nonetheless, EPA did incorporate additional costs for two of these four plants to install and operate recirculation pumps and piping based on specific comments from another commenter (see EPA-HQ-OW-2009-0819-8456-A1). See the comment response to code 7 (Industry Profile & Plant Operations) and the "Methodology for Estimating Bottom Ash Transport Water Compliance Costs for the Final Revisions to the Steam Electric ELGs – DCN SE08505" memo for additional information. EPA did not estimate ELG compliance costs for process changes and/or equipment that plants *may* need to meet site-specific discharge limitations established by permitting authorities using BPJ.

Citing EPA's record and one commenter's assessment of pollutant loadings (see Appendix H of EPA-HQ-OW-2009-0819-8293), another commenter asserted that the environmental impact, in pounds and toxic-weighted pound equivalents (TWPE) discharges, of a 10 percent volumetric purge allowance is minimal. EPA's estimates are consistent with this commenter, as the Agency found small environmental [72] Nevertheless, as discussed elsewhere in the record, the final rule is not based on a cost benefit comparison, or a cost per pound removed basis (as is done for BPT), as that may impermissibly conflate the BAT and BPT standards, contrary to the holding of *SWEPCO v. EPA*. 905 F.3d 999, 1026 (5th Cir. 2019). EPA also notes that the final rule will significantly reduce pollutant loadings discharged in BA transport water and subsequently, environmental impacts relative to current discharges. See the response to code 27 (Environmental Assessment - General Impacts & Exposure Pathways) and the Supplemental EA Report for more information on environmental impacts associated with pollutants present in BA transport water and incremental change in environmental impacts under the final rule.

EPA does not agree with one commenter who asserted that the estimated toxic weighted pound equivalents (TWPE) in source waterbodies (prior to any industrial use) are higher than TWPE in BA transport purge. The rulemaking record demonstrates that the energy production process itself is contributing to the quantity of the pollutant present in BA transport water, rather than simply the source water. See Section 6.3.1 of the Supplemental TDD (EPA-821-R-20-001) for EPA's pollutant loadings analyses and the response to code 19 (BA Transport Water – General) for EPA's assessment of commenters' pollutant loadings analyses and estimates.

22 BATW – Best Management Practice Plan

With respect to comments on EPA's cost analysis for the best management practice (BMP) plan, EPA projects that six EGUs at four plants would qualify for the low utilization subcategory in the final rule.[73] EPA has confirmed that each would incur the costs of a BMP plan under the final rule analysis. EPA estimates that these costs are much less than converting BA handling systems, and thus EPA disagrees that they are onerous.

EPA disagrees with the commenter's alternate formulations of the BMP plan. The suggested two-tier approach would allow power plants to operate the BA transport water system consistent with "existing BATW recycle technologies," and therefore might allow once-through technologies to discharge 100 percent of the BA transport water without any further consideration of whether some of that water could easily be recycled with, for example, the purchase of a single additional pump or length of pipe. EPA also disagrees with the "practicable" test posited by commenters. The purpose of the BMP plan is to increase the amount of BA transport water recycled and therefore decrease the amount of BA transport water discharged. It

[72] EPA's pollutant loading analyses are based on an assumed 10 percent purge at each affected facility, and therefore overestimates pollutant discharges associated with the BAT system for BA transport water.

[73] Three EGUs at one power plant have announced their retirement since this analysis; however, this would not change the conclusions of EPA's analysis. Furthermore, to the extent that EGUs can demonstrate low utilization as late as 2023 under the final rule, additional EGUs at additional power plants may ultimately make use of this provision.

would be an unreasonably challenging task to require power plants with a CUR less than 10 percent, which tend to be on the margins of profitability, to expend additional resources to evaluate the pollutant removals of wastewater treatment technologies and compare these to the pollutant removals associated with various recycle rates before ultimately selecting one of these alternatives. Finally, the recommended approach adapting EPRI (2018) mitigation solutions includes 37 items.[74] This significant list of items which the commenter acknowledges is not exhaustive of what the commenter believes should be included, would potentially be more effort and cost than simply implementing the generally applicable limitations associated with high recycle rate systems. It is unclear that requiring these additional measures would increase recycling significantly compared to EPA's BPM plan requirements in 423.13(k)(3) of the final rule, which already require consideration of the following:

- Preventative maintenance.
- Inspections.
- Segregating other process waters.
- Minimizing stormwater.
- Performing in-line treatment.
- Optimizing/installing equipment to increase recycling.
- Maximizing BA transport water recycled into the BA system or FGD system.

With respect to the commenters' recommended edits to the regulatory text, commenters suggested that section 423.19(d)(1) be modified to state the BA transport water BMP plan certification is due with the permit application "or within two years [of the final rule effective date], whichever is later." EPA agrees that this allows flexibility where a permit is recently issued or pending. EPA also agrees that the word "approved" confuses the meaning of section 423.19(d)(3)(D), and therefore the Agency has removed it. EPA disagrees with commenters that there is no requirement of inspection reports in the BMP plan text. However, these inspections are not "annual" and therefore the Agency has removed that adjective to avoid confusion.

23 Bottom Ash Transport Water – Zero Discharge

As described in section VII.B.2 of the preamble, EPA determined that the basis of the bottom ash (BA) transport water best available technology economically achievable (BAT) limitations is the use of high recycle rate (HRR) systems. This response expands on the rationale discussed in the preamble in order to address issues raised by public comments categorized as code 23 (BA Transport Water – Zero Discharge). The response has been organized into subtopics; identified by subheadings in the response below. This response covers the following subtopics.

- Rationale for not selecting closed-loop systems as BAT.

[74] The EPRI report at times focused on how to eliminate discharges, and EPA has rejected a zero-discharge BAT basis for BA transport water as discussed in Section VII.B.2 of the preamble.

- Rationale for not selecting dry BA handling systems as BAT.
- 2015 Rule Baseline cost estimates and adjustments to RO systems methodology.
- Compact submerged conveyor (CSC) systems.
- Duke Energy Belews Creek BA system.
- BAT for low utilization systems.

Rationale for not selecting closed-loop systems as BAT

EPA disagrees with commenters who asserted that the Agency inappropriately weakened the BA transport water limitations and that revisions to the 2015 BA transport water requirements were unjustified. As described in section VII.B.2 of the preamble, EPA's understanding of the ability of wet BA systems to operate a true closed-loop system (or achieve complete recycle) changed following the publication of the 2015 rule.

With respect to systems that recycle BA transport water, utilities and trade associations, in their petitions for reconsideration and in meetings with EPA, stated that many existing remote mechanical drag system (MDS) installations are, in reality, "partially closed" rather than a fully closed-loop, as assumed by EPA in the 2015 rule. According to these petitions, plants operate these systems partially closed due to small discharges associated with additional maintenance and repair activities that were not accounted for in the 2015 maintenance allowances; water imbalances within the system such as those associated with stormwater following larger precipitation events; and water chemistry imbalances including acidity and corrosiveness, scaling, and fines build-up.

While some facilities have controlled or eliminated these challenges with relatively straightforward steps, others require more extensive process changes and associated increased costs or find these challenges difficult to resolve. Just as EPA estimated costs of chemical additions in the 2015 rule to manage scaling, EPA estimated costs in the final rule for plants to make use of reverse osmosis (RO) filters to treat a slip stream of the recycled water to remove dissolved solids (see section 5.3 of the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001) (Supplemental TDD)). EPA recognizes that plants could also add additional treatment chemicals (caustic) to manage acidity or other chemicals to control alkalinity, add polymer to enhance settling and removal of fine particulates ("fines"), or build storage tanks to hold water during infrequent maintenance or precipitation events to achieve complete recycle.

EPA also recognizes the challenges of operating a truly closed-loop system discussed above are compounded when considered in conjunction with the requirements of the CCR Part A rule. See section VII.B.2 of the preamble for more information.

EPA disagrees with commenters who asserted that the Agency is "backsliding" or "downgrading" the BAT standard by selecting HRR systems as the BAT technology basis and establishing new limitations based on this selected technology, rather than fully closed-loop BA systems. The Agency has authority to revise a rule. *See Clean Water Action v. EPA*, 936 F.3d 308, 313-314(5th Cir. 2019)("[A]dministrative agencies possess the inherent authority to revise previously-promulgated rules, so long as they follow the proper administrative requirements and provide a reasoned basis for the agency decision.") (citing *F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Automobile Insurance Co.*, 463 U.S. 29, 42 (1983); *Perez v. Mortg. Bankers Ass'n*, 135 S. Ct. 1199, 1206 (2015)). (See also comment response to comment code 1.)

Furthermore, this change is not prohibited by the antibacksliding provision in Section 402(o) of the Clean Water Act (CWA) or its implementing regulations, as some commenters asserted. Section 402(o) of the Act prohibits (with exceptions) revision of technology-based effluent limitations derived using best professional judgement (BPJ) to become less stringent based on a subsequently enacted effluent guideline. CWA Section 402(o) refers to effluent limitations established under section 402(a)(1)(B), which provides authority for BPJ-based limitations under the Act. Section 402(o) does not speak to changing effluent limitations based on revised promulgated effluent guidelines under sections 301 and 304, as EPA is doing in the final rule (or 307/306). Similarly, the anti-backsliding regulations at 40 CFR 122.44(l) prohibit (with exceptions) backsliding of a BPJ-based effluent limitation, not one based on a revised effluent guidelines rule. And the permitting regulation at 40 CFR 122.62(a)(3)(B) expressly contemplates permit modifications to accommodate a revision of an effluent limitation guideline on which a permit condition was based.

Due to the process changes required to achieve true zero discharge in combination with the CCR Part A rule, EPA determined that the use of HRR systems rather than dry BA handling or closed-loop BA systems, are BAT. EPA's conclusion is based on its discretion to give particular weight to the CWA section 304(b) statutory factor of "process changes." Process changes to existing HRR systems that do not currently operate as fully closed-loop, or that will be installed in the near-future, to comply with this rule in conjunction with the CCR Part A rule could be more challenging without a further discharge allowance, and in some cases could also result in the prolonged use of unlined surface impoundments.

EPA disagrees with some commenters who asserted that a plant operator's ability to collect and sell BA for beneficial reuse demonstrates that zero discharge systems are the BAT. Plants operating wet BA systems, including surface impoundments and HRR systems, can also sell dewatered BA. The fact a plant sells its BA does not mean the plant operates a zero discharge BA system nor does it demonstrate such systems are the BAT.

EPA estimates small environmental changes associated with changes in pollutant loadings for HRR systems compared to baseline, including small changes in impacts to wildlife and humans.[75] See the Supplemental EA Report and the response to code 27 (Environmental

[75] EPA's pollutant loadings analyses were based on an assumed a 10 percent purge at each affected plant, and therefore, likely overestimate BA pollutant loadings.

Assessment - General Impacts & Exposure Pathways) for more information on environmental impacts associated with pollutants present in BA transport water and incremental change in environmental impacts under the final rule. See the response to comment code 19 (BA Transport Water – General) for more information on EPA's selection of HRR systems as the BAT technology basis for BA transport water.

Rationale for not selecting dry BA handling systems as BAT

EPA disagrees with commenters who asserted that dry BA handling systems, such as under-boiler MDS, pneumatic conveyance systems, and CSC systems, represent the BAT technology basis for BA. See section VII.B.2 of the preamble for EPA's rationale for not selecting specific dry BA handling technologies.

EPA disagrees with commenters who asserted EPA should conduct a plant-by-plant analysis of dry BA handling systems. EPA is not required in effluent limitation guidelines to do a plant-specific analysis. *See Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 237-38 (5th Cir. 1989) ("The EPA is required to consider costs only for a category or subcategory of plants; it is not required to determine costs on a plant-by-plant basis.") (citing *E.I. du Pont de Nemours & Co. v. Train,* 430 U.S. 112, 128-30 (1977); *BASF Wyandotte Corp. v. Costle,* 598 F.2d 637, 662 (1st Cir. 1979); *Am. Iron & Steel Inst. v. EPA,* 526 F.2d 1027,1051 (3d Cir. 1975)).

Furthermore, EPA does not have plant-specific information to make a determination on what type of BA handling system is most appropriate (e.g., EPA does not have plant-specific information about headspace below the boiler or boiler house configuration to determine if a MDS installation is appropriate for that plant). Where commenters stated they do not have enough room in their plant for a specific type of BA handling system, EPA accounted for this in the technology selection analysis.

Additionally, EPA disagrees with one commenters' approach to calculating cost estimates for dry BA handling and closed-loop BA systems. As described in the response to comment code 21.b (BA Transport Water – HRR Systems – Costs & Loads), EPA cannot fully evaluate or provide a detailed response to the MDS and remote MDS cost estimates and methodology used in the commenter's analysis because they failed to provide actual costs or sufficient information on how they were calculated. However, the Agency identified notable differences in the commenter's assumptions about the configurations of the MDS and remote MDS installations (e.g., number of units assumed per plant, equipment included in each installation) and the population of electric generating units assumed to require full conversion costs. See response code 21b for further discussion and response to this comment.

2015 Rule Baseline cost estimates and adjustments to RO systems methodology

For the final rule, EPA updated its estimated costs to comply with the 2015 rule (baseline) BAT for BA transport water to include a high-pressure RO system to remove dissolved solids and facilitate complying with a zero discharge standard. EPA disagrees with commenters who asserted that RO technology for eliminating purge is technically challenging and costly when deploying closed-loop remote BA dewatering.

In estimating baseline costs for the final rule, EPA incorporated costs associated with transport and disposal of RO brine including costs associated with hauling the brine offsite to a centralized waste treatment (CWT) facility for disposal (see section 5.2.5 of the Supplemental TDD).

EPA disagrees with commenters who asserted that that closed-loop BA systems are not economically achievable. As described in section VIII.B.2 of the preamble, EPA has selected HRR as the technology option due to process changes relating to compliance with the CCR Part A rule. As stated in the response to comment code 19, while EPA found the closed-loop systems have higher costs, EPA did not find that the estimated additional cost to industry would result in additional plant closures.

EPA disagrees with commenters who asserted that estimating baseline costs for all plants installing or currently operating HRR systems to install RO treatment of BA purge water is unreasonable and irrational. While EPA determined that it is not likely that all plants would incur these additional costs to achieve zero discharge, EPA had no means to predict which plants would ultimately incur these additional costs, and thus EPA reasonably assumed, for purposes of its economic achievability analysis, that each plant installing or operating a remote MDS would incur these costs in order to ensure that the costs upon which economic achievability are based are not underestimated.[76]

For the final rule, EPA estimated plants installing RO to achieve complete recycle for a 10 percent BA purge water volume will average capital costs of $5,970,000, O&M costs of $794,000, and total annualized costs of $1,360,000 (2018$).[77] EPA notes its average compliance costs to achieve zero discharge of BA transport water are greater than those submitted in public comments detailing the various approaches for seven plants to achieve zero discharge of BA transport water. As stated above, EPA did not find that the estimated additional cost to industry would result in additional plant closures.

EPA disagrees with the commenter who asserted that RO “does not address modifications necessary to eliminate unintentional purges that could confound compliance with a no discharge of BA transport water requirement.” It is not EPA’s intention to capture leaks as part of the 2015 zero discharge requirements. Specifically, EPA defined transport water as excluding “low volume, short duration discharges of wastewater from minor leaks (e.g.*,* leaks from valve packing, pipe flanges, or piping), minor maintenance events (e.g.*,* replacement of valves or pipe sections)” (see 40 CFR section 423.11(p)). In addition, EPA received no plant-specific comments detailing the need for any added infrastructure to handle such leaks from the system.

[76] For the final rule, EPA did not estimate costs associated with RO treatment of a BA purge stream for plants expected to install a MDS.

[77] EPA’s compliance cost estimates were based on a RO treatment system sized for 10 percent purge at each affected facility, and therefore likely overestimates costs associated with the zero discharge limitation.

CSC systems

Some commenters asserted that CSC systems (referred to by the most commonly sold system, "submerged grind conveyors," in the proposed rule and in many public comments) should be the basis for setting nationally applicable BAT requirements, and other commenters asserted that these should not be the basis for nationally applicable BAT. For the reasons described in section VII.B.2 of the preamble, EPA has not selected CSC systems and BAT and instead selected HRR systems as the technology basis for establishing BAT requirements to control pollutants discharged in BA transport water. Based on conversations EPA had with CSC technology vendors, EPA agrees that CSC systems may not be universally applicable due to space constraints and ash loading rates. See the memorandum titled "Compact Submerged Conveyor Technology for the Management of Bottom Ash – DCN SE08509".

Duke Energy Belews Creek BA System

One commenter asserted that Duke Energy is not using their BA system to the fullest pollution control capacity. Specifically, this commenter asserts Duke Energy is taking a tax credit for operating dry bottom ash handling; yet they are letting the system rest 10 percent of the time. EPA visited the Duke Energy Belews Creek facility on December 13, 2017 and the Agency's site visit notes state that, "Belews Creek asserts that remote SFC systems must 'rest' for 10 percent of the operating time to allow fines to settle and be carried out on the drag chain conveyor." This is done to maximize settling time and remove fines. Although the system is technically not sluicing BA from the boiler to the conveyor, it is a step in the treatment process done in order to achieve complete recycle. This is an operational requirement for how Belews Creek achieves zero discharge (see DCN SE07137). ELGs only require plants to meet pollution limitations, they do not dictate a specific technology that must be used to comply or how that technology must be operated.

BAT for low utilization systems

See response to comment code 9.b (Subcategorization – Low Utilization) for EPA's response to comments regarding the selection of BAT for the low utilization subcategory.

24 BATW – Other Technologies

No comment excerpts were received on this topic.

25 Non-Water Quality Environmental Impacts

One commenter asserted that brine resulting from use of membranes to treat FGD wastewater could be better managed using grout than by using paste because grout is already a solid that can be landfilled or beneficially reused. Both grout and paste are similar in practice to the encapsulation technology that EPA evaluated as one of the disposal methods for the FGD membrane filtration technology basis for the VIP program. These technologies mix brine with fly ash and lime to allow for solidification, but in different ratios. EPA cannot predict the ratios of fly ash, lime, and Portland cement that plants will use for solidification (for either grout or encapsulation) because the optimal ratio is highly site specific. Paste differs from encapsulation in that it typically requires smaller quantities of fly ash and lime and results in a pumpable material, rather than a solid that is transported via truck. EPA does not have, nor did the commenter provide, sufficient data to evaluate the commenter's claims that paste increases electricity cost, landfilling cost, CO2 emissions, or risk of landfill leachate blowout relative to grout or encapsulation.

EPA agrees with the commenter that there may be beneficial reuse opportunities using the resulting "cement-like grout" from the encapsulation process and expects plants that opt into the VIP may avail themselves of these opportunities. However, EPA's technical analyses assume that plants will instead landfill the material because EPA lacks both industry-wide and plant-specific market information on whether or not plants may have an available market for beneficial reuse. This assumption may result in an overestimate of the costs of disposal. See Section 5.2.5 of the Supplemental TDD and EPA's response to comment code 5 (Regulatory Options - Compliance Costs Methodology) for more information on EPA's assumptions for the membrane filtration technology option.

As described in the preamble, part EPA's rationale for rejecting membranes as BAT for all existing facilities is because it could discourage beneficial reuse of FA (such as replacing Portland cement in concrete) causing more FA to be incorporated in wastes being disposed.[78] While EPA agrees with commenters that there are several alternative ways to treat or dispose of the brine generated by membrane filtration, including incorporating it into some present beneficial uses of fly ash, the method EPA projected to be employed due to its lower costs is encapsulation with FA and lime for disposal of the resulting solid in a landfill. EPA does not dispute that some plants have fly ash availability, either in silos or currently landfilled, and that there may be market availability for other CCR materials (DCN SE09070).Alternatively, it is likely that some plants are located in markets with limited FA availability, meaning that if FA is used for encapsulation purposes, then it could not also be used for beneficial reuse purposes or that the plant would have to purchase additional FA. EPA lacks region-specific data that would allow it to more fully evaluate FA market conditions on a plant-by-plant basis.

The final rule does not require steam electric power plants to use any specific technologies to comply with the final rule requirements, and if a plant chooses to participate in the VIP, it can take advantage of the beneficial reuse opportunities discussed by the commenter, such as utilizing grout disposal rather than paste disposal.

26 EA – Scope

No comment excerpts were received on this topic.

[78] While EPA considers FA use for waste solidification and stabilization as beneficial use, the CCR waste being solidified or stabilized must still be disposed of in accordance with 40 CFR 257.

27 EA – General Impacts and Exposure Pathways

Environmental and human health effects of pollutants from steam electric wastewater

Some commenters noted that the steam electric power generating industry discharges large quantities of pollutants. These commenters also assert that the effects of these discharges on the environment, human health, and the utility of surface water for a variety of uses are documented in extensive scientific literature and case studies. EPA has estimated the pollutant loads from the industry and evaluated potential environmental and human health effects of these discharges. See the *Supplemental Environmental Assessment for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental EA) (EPA-821-R-20-002), which included a focused literature review and quantitative modeling of potential impacts resulting from discharges of flue gas desulfurization (FGD) wastewater and bottom ash (BA) transport water, which are the subject of the final rule.

Multiple commenters asserted that steam electric power plants, mostly coal plants, are responsible for the majority of arsenic, lead, mercury, selenium and other toxic metals discharged into our nation's rivers, lakes, and streams every year. EPA disagrees that these plants are responsible for the majority of these pollutant discharges. EPA notes that while the preamble for the 2013 Proposed *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2013 proposed rule) stated "each year the pollutant discharges from this industry are increasing in volume and total mass, and currently account for approximately 50–60 percent of all toxic pollutants discharged into surface waters by all industrial categories currently regulated under the CWA," EPA updated this assessment and found that discharges from steam electric power plants "account for about 30 percent of all toxic pollutants discharged into surface waters by all industrial categories regulated under the CWA" in the preamble for the 2015 *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2015 rule). The assessment for the 2015 rule reflected changes to the population of coal-fired power plants in operation, as well as updates to the discharge of loadings associated with FGD wastewater and BA transport water, a number which EPA finds has continued to decrease due to additional electric generating units retiring and repowering since the 2015 rule.

Steam electric wastewater discharges from specific plants

Multiple commenters provided information on operations at specific steam electric power plants and/or pollutants present in FGD wastewater and BA transport water from specific steam electric power plants. As part of its literature review for the Supplemental EA, EPA reviewed relevant documents submitted as attachments to public comments. The memorandum titled "Methodology and Results for Targeted Literature Search for the 2020 Steam Electric Supplemental Environmental Assessment – DCN SE08758" documents the methodology and results of this review.

Multiple commenters provided comments on EPA's proposed regulations for BA transport water. One commenter provided information on BA transport water discharges from Ameren-Missouri's plants on the Mississippi River and Missouri River and asserted that under the 2015 rule these plants would have no discharges of BA transport water but under the proposal they would discharge up to 14 million gallons per day of BA transport water. Another commenter provided information about BA transport water discharges from Fort Martin plant and asserted that zero discharge technologies are available and achievable for this plant.

EPA proposed that discharges of BA transport water be controlled based on high recycle rate systems, rather than dry handling or closed-loop systems, as in the 2015 rule. Since the 2015 rule, EPA's understanding has changed regarding the types of available dry systems, and the ability of wet systems to operate a true closed-loop system (or to achieve complete recycle) has changed. Under the final rule, the permitting authority is charged with establishing BAT limitations associated with BA transport water purges on a case-by-case basis using best professional judgment. In addition, CWA section 301(b)(1)(C) requires the permitting authority to impose more stringent effluent limitations, as necessary, to meet applicable water quality standards. This BPJ provision in the final rule is intended to limit BA transport water discharges at all plants based on the site-specific facts. As the preamble discussion makes clear, EPA's decisions on the final rule are based on the factors specified by Sections 301, 304, and 306 of the Clean Water Act – most importantly, the technologies selected in the final rule are "available" and "demonstrated" and the final rule is "economically achievable" for the industry as a whole. See Section VII of the preamble and the response to Codes 19 (BA Transport Water – General) and 23 (BA Transport Water – Zero Discharge) for more details on EPA's rationale for establishing BAT for controlling pollutant discharges in BA transport water.

One commenter discussed the Ameren Labadie Energy Center, located on the Missouri River, and asserted that discharges from this plant to surface and groundwater may affect downstream drinking water intakes that provide drinking water for Missouri residents. This commenter asserted that "[a]llowing discharges to continue, even at reduced flow, will continue to put the drinking water of Missouri's citizens at risk." EPA disagrees with this commenter because steam electric power plants will have to meet BAT limitations established by the permitting authority based on site-specific facts and the permitting authority's best professional judgment. Additionally, if the permitting authority determines that BAT-driven discharge limits would not meet the water quality standards of the receiving water, the CWA requires the permitting authority to include more stringent limitations known as water quality-based effluent limits. See Section XIII.B of the preamble for more details regarding limitations for BA transport water.

EPA's Coal Combustion Residuals (CCR) Part A rule addresses coal-fired power plant use of surface impoundments for waste management. Issues related to combustion residual leachate are not within the scope of the final rule. For additional information, see Section IV.D of the preamble.

Two commenters provided information on discharges from the TVA Cumberland Plant in Tennessee and noted that the plant is upstream of park land and a wildlife management area. The commenters provided mercury and selenium loadings data for the plant, noting that both pollutants have environmental and human health impacts. Under the final rule, the Cumberland Plant meets the criteria for the high flow subcategory and FGD wastewater limitations for that plant will be based on the use of chemical precipitation. EPA's rationale for the high flow subcategory is based on the statutory factors in CWA section 304(b)(2)(b) and discussed in the preamble and in the response to Code 9 (Subcategorization – General). Use of chemical precipitation to treat FGD wastewater will effectively reduce the levels of mercury and EPA expects that system to also provide ancillary selenium removals from FGD wastewater (see Section 8 of the Supplemental TDD). See Section VII.C.1 of the preamble for more details on requirements for plants qualifying for the high flow subcategory and the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental TDD) (EPA-821-R-20-001) for information on pollutant discharge limitations and the pollutant removal effectiveness of available treatment technologies. As noted above, if these technology-based limits do not meet water quality standards in the receiving waters, the permitting authority may require more stringent water quality-based effluent limits.

Multiple commenters provided comments on the ecological impacts of selenium discharges from coal-fired steam electric power plants, such as Belews Creek Plant, Fort Martin, Cumberland, and Cliffside Plant. One commenter stated that selenium discharges from Fort Martin Power Plant in West Virginia exceed the limitations in the plant's National Pollutant Discharge Elimination System permit WV0004731; that the receiving stream (Crooked Run) is on the 303(d) list for biological impairments; and that "[a]llowing Fort Martin to discharge more selenium would further impair this already damaged stream." Multiple commenters provided comments on the impacts of mercury and cadmium. EPA agrees with commenters that selenium, mercury, and cadmium are known to bioaccumulate in aquatic systems and, at high enough levels, can have adverse effects on wildlife. See Section 3.3 of the *Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2015 EA) (EPA-821-R-15-006) and Section 2.2 of the Supplemental EA for a discussion of the literature on the impacts of selenium, mercury, and cadmium on wildlife and human health. EPA's final rule addresses selenium and mercury discharges to surface waters by establishing limitations for selenium and mercury levels in FGD wastewater and BA transport water discharges. In addition, while the final rule does not set limitations on cadmium discharges, cadmium will be controlled via regulation of other parameters in FGD wastewater and BA transport water (see Section 8 of the Supplemental TDD). See Section XIII.A of the preamble, the response to Code 43 (Numeric Limits), and the Supplemental TDD for more details on selenium limitations. Also see Section VII of the preamble for a discussion of EPA's determination of BAT for the final rule.

See Section XII of the preamble, the BCA Report, and the response to Code 41 (Benefits) for EPA's discussion of monetized and non-monetized benefits of the final rule.

Leaking CCR disposal surface impoundments

Commenters presented information on impacts associated with leaking CCR disposal surface impoundments contaminating ground water and ultimately surface water. EPA agrees with the commenters that unlined surface impoundments can be sources of surface or groundwater contamination. As noted above, the final rule does not identify unlined surface impoundments as BAT for BA transport water, except for one subcategory as discussed in Section VII.C of the preamble. Issues related to combustion residual leachate are not within the scope of the final rule. For additional information, see Section IV.D of the preamble. EPA also notes that the use of unlined surface impoundments for waste management at coal-fired power plants is addressed in EPA's CCR Part A rule.

28 EA – Halogens/Drinking Water Impacts

General impacts of halogens on drinking water quality

As described in the final rule preamble and supporting documents, EPA considered halogens for estimating pollutant loadings, for assessing environmental effects, and for estimating benefits as part of its benefit-cost analysis conducted pursuant to Executive Order 12866. EPA does not consider risks in establishing these technology-based effluent guidelines. See responses to comments in Comment Code 1 (Legal Authority).

Some commenters stated that the scientific literature indicates bromides "can lead to the formation of trihalomethanes [THMs] in drinking water supplies" and the "addition of bromide to source water can increase both the overall level of trihalomethanes and the prevalence of brominated species." Commenters explained that THMs are a type of disinfection byproduct (DBP), and concentrations of both total and brominated THMs in treated water have been shown to be associated with bromide concentrations in source water. EPA agrees with these commenters and also agrees with the commenter who stated that scientific literature indicates that, "organic disinfection byproduct precursors react preferentially with bromine over chlorine, generating higher concentrations of brominated trihalomethanes." EPA included a summary of the peer-reviewed literature on the formation and potential impacts of brominated disinfection byproducts in Section 2.1.2 of the *Supplemental Environmental Assessment for the Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-002) (2020 Supplemental EA).

Another commenter stated that, "[b]romide present in source water creates treatment challenges for drinking water systems because it reacts with the disinfectant chemicals used to kill harmful pathogens to form carcinogenic disinfectant byproducts." One commenter noted that, "[o]f the four trihalomethane species regulated by EPA with a cumulative maximum contaminant level (MCL), two, bromoform and bromodichloromethane, have [an] MCL goal of zero." See Table 2-1 in Section 2 of the 2020 Supplemental EA for a table listing the MCLs and MCLGs for regulated DBPs. As noted in the comments, some drinking water treatment plants (DWTPs) downstream from steam electric power plants have reported concentrations of total trihalomethanes (TTHMs) above the EPA MCL of 80 parts per billion (ppb).

As described in the final rule preamble and supporting documents, the occurrences of these issues at DWTPs is limited and driven by site-specific factors. One commenter also noted that scientific literature indicates THMs "can increase the risk of cancer, and can lead to liver, kidney, or central nervous system disease." See Section 2.1.2 of the 2020 Supplemental EA for a review of the peer-reviewed literature on the human health effects of DBPs. To address these potential human health risks, EPA previously established Maximum Contaminant Levels (MCLs) and Maximum Contaminant Level Goals (MCLGs) for DBPs and promulgated the Disinfection Byproduct Rules (Stage 1 and Stage 2). To comply with the MCLs, DWTPs undertake actions to control DBP levels, including, in some cases, installation of additional treatment technology.

EPA evaluated bromide loadings from coal-fired power plants (see Section 6 of the Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA-821-R-20-001) (Supplemental TDD)). As described in Section XII of the final rule preamble, the analysis of changes in downstream bromide concentrations associated with changes in bromide discharges are concentrated at a small number of sites. This supports EPA's determination that potential discharges are best addressed using site-specific, water quality-based effluent limitations established by NPDES permitting authorities for the small number of steam electric power plants that may impact downstream drinking water treatment plants. See Section 2.1.2 of the Supplemental EA for further discussion on the influence of bromides on DWTP source waters, including the potential for formation of DBPs, and Section XIV(C) of the preamble to the final rule and EPA's responses to Comment Code 36 (Regulatory Implementation – Halogens) for details on EPA's recommendation for bromide discharges.

Contribution of power plants to halogens in source water/formation of brominated DBPs

One commenter noted that coal-fired power plants are not the only source of bromides in source water and that, "in some circumstances elevated levels of TTHM may be attributed to inappropriately designed water treatment systems or systems operating below the original design basis where chlorinated water is retained for an extended period of time in storage tanks and distribution piping, which would facilitate formation of TTHM." Other commenters indicated that elevated concentrations of brominated DBPs downstream of steam electric power plants might be associated with other sources of bromide. EPA agrees that bromides may be introduced to DWTP intake water from numerous sources; however, coal-fired power plants are a known source of bromide discharges which EPA has appropriately evaluated in the context of this rulemaking. See Section 2.1.2 of the 2020 Supplemental EA for a review of peer-reviewed studies on the association between bromide concentrations at DWTPs and proximity to steam electric power plants.

EPA agrees that a variety of factors can influence the development of brominated DBPs, as noted in the comments, and discusses these factors in Section 2.1.2 of the 2020 Supplemental EA.

One commenter stated that, "substituting chloramines for chlorine creates other problems for downstream drinking water users: chloramines are linked to health problems such as respiratory irritants, severe skin reactions, and greater exposure to pathogens in the water." The commenter pointed to case studies that have elaborated on potential complications associated with the use of chloramines for disinfecting purposes. EPA acknowledges that modifications at DWTPs to address disinfection byproduct levels in drinking water vary in their advantages and disadvantages, as noted in Section 2.1.2 of the 2020 Supplemental EA.

Estimation of bromide loads

See the response to Comment Code 13 (FGD Wastewater - Halogens) for information on EPA's methodology used to calculate loadings of bromides. This response includes EPA's considerations regarding availability of data on halogen loadings from coal-fired steam electric power plants to DWTPs.

One commenter provided information regarding modeling downstream transport of bromide to POTWs using the D-FATE model. See the response to Comment Code 41 (Benefits) for more information on the D-FATE model and quantification of benefits.

Control of Halogens through Effluent Limitation Guidelines

Some commenters asserted that EPA should establish Effluent Limitation Guidelines (ELGs) for halogen discharges from steam electric power plants, and other commenters asserted that halogen limitations should not be established in this rulemaking. ELGs are national standards for wastewater discharges to surface waters and municipal sewage treatment plants that are developed by EPA. ELGs are designed to control pollution through the use of best available technology that is economically achievable for an industry. EPA is not promulgating halogen requirements in the final rule. See Sections VII.B.1 and XIV(C) of the preamble to the final rule and responses to Comment Code 36 (Regulatory Implementation – Halogens) for a discussion of EPA's reasoning.

One commenter stated that "health impacts from bromide do not support the inclusion of a bromide limit in the Proposed Rule, particularly for discharges to estuarine, marine, or tidally influence environments" and "where it is necessary to bring drinking water treatment facilities into compliance with TTHM requirements, it may be more appropriate and cost-effective to modify the water treatment facility or the water treatment process itself, rather than set a national standard for bromide." Another commenter stated "[b]y failing to put a limit on bromide discharges, EPA shifts the burden of dealing with the downstream impacts of bromide pollution onto already-burdened drinking water utilities, which are often small, rural municipalities" and "an effluent limitation based on membrane filtration is sorely needed to control bromide." For the final rule, EPA did not promulgate generally applicable bromide requirements. EPA recommends consideration of human health, drinking water treatment, and other impacts from bromide discharges on a site-specific basis by permit writers under the separate water-quality-based provision of the Act, section 301(b)(1)(C), where necessary to meet applicable water quality standards. See Section XIV(C) of the preamble to the final rule and responses to Comment Code 36 (Regulatory Implementation – Halogens) for a discussion of EPA's rationale for this approach. For a discussion of human health impacts associated with brominated DBPs, see Section 2.1.2 of the 2020 Supplemental EA.

Multiple commenters noted inaccuracies in previous EPA publications and the peer-reviewed literature that EPA examined in this rulemaking process. One commenter said that a literature review by the Electric Power Research Institute (EPRI) identified errors with the methodology used for EPA's Stage 2 Disinfectants and Disinfection Byproducts Rule. Another commenter discussed inconsistencies between bromide concentrations in the Ohio River as modeled by Cornwell (2018) and measured by the Ohio River Valley Water Sanitation Commission. Another commenter stated that Good and VanBriesen (2019) used flawed methodology to estimate DBP risks to downstream drinking water sources. Comments regarding EPA's Stage 2 Disinfectants and Disinfection Byproducts Rule are outside the scope of the ELGs. See the response to Comment Code 13 (FGD Wastewater – Halogens) regarding the modeling and methodology documented in literature sources.

Iodine

One commenter asserted that there are "non-coal sources of iodine include pharmaceuticals and FDA required levels in table salt" to source water for DWTPs. EPA agrees that pharmaceuticals and contrast agents can be sources of iodine, but EPA does not have information in this record sufficient to evaluate their overall contribution to source water. As part of the final rule analysis, EPA estimated potential iodine loadings from steam electric power plants based on native iodine content in coal and addition of iodine for enhanced mercury emission control. See Section 6 of the Supplemental TDD.

Another commenter asserted that, "[a]ny potential impact of iodine or other halogens to downstream water treatment is dependent on multiple factors, including: the amount of iodine or halogen in the water from natural or nonpower-plant sources, the amount of iodine or halogen discharged by the power plant; the volume of flow of the water into which such halogen is discharged; and the distance from the point of discharge to the water treatment facility." EPA agrees that there may be numerous factors that influence the formation of iodinated DBPs at DWTPs. See Section 2.1.3 of the 2020 Supplemental EA for a discussion of iodine in coal-fired power plant discharges.

Another commenter asserted that, "[m]ost research to date on DBP formation has focused on chlorine or bromine, with significantly less research on iodine." EPA agrees and notes that the formation and effects of iodinated DBPs in drinking water treatment systems is the subject of ongoing research and is more uncertain than similar relationships for brominated DBPs. See

Section 2.1.3 of the 2020 EA for a summary of research published to date on iodine and iodinated DBPs.

One commenter stated that, "[r]egardless of the regulatory approach to bromine in the Steam Electric ELG, it is neither appropriate nor scientifically justified to include iodine or other halogens without discrete review of the impact of each halogen. Significant additional research on iodine and potential DBP formation would be required prior to an assessment of the appropriateness of any regulatory restrictions." EPA notes that the question for the determination of BAT is not what impacts EPA can prove for each pollutant, but rather what technology is BAT, and given that technology basis, what pollutants can be removed. Here, EPA has determined that BAT is CP+LRTR as discussed in Section VII.B.1 of the preamble. Since the BAT selected does not treat iodine, EPA has not established iodine limitations. The commenter also stated that "[g]iven the variabilities due to downstream effects, it appears any such regulatory approach should be determined at the local rather than national level, where the specifics of other contributors, water flow, and distance could be appropriately taken into account." EPA agrees that potential halogen discharges are best addressed using site-specific, water quality-based effluent limitations established by NPDES permitting authorities. See Section XIV(C) of the preamble to the final rule for a discussion of EPA's recommendations regarding site-specific consideration of halogen discharge.

29 EA – Immediate Receiving Water (IRW) Model

A commenter provided information regarding the identification of the immediate receiving water for discharges from the Dallman Plant. Based on the information provided by the commenter, EPA updated the immediate receiving water for Dallman to the stream reach associated with the referenced geographic coordinates on the Sangamon River. This update is included in the Immediate Receiving Water (IRW) Model, as documented in the memorandum titled "Receiving Waters Characteristics Analysis and Supporting Documentation for the 2020 Steam Electric Supplemental Environmental Assessment – DCN SE08753."

One commenter focused on modeled exceedances of reference dose benchmark values in the IRW Model and asserted that the rule would have disproportionate impacts on children consuming fish. EPA disagrees as it is necessary to consider more than one criterion to properly assess whether disproportionate impacts to children may exist. See Section H (Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks) of the final rule preamble for details on EPA's evaluation of the estimated potential effects to children presented by the regulatory options. EPA's analysis indicates that the regulatory options, including the final rule, would have a small, and not disproportionate, impact on children.

One commenter asserted that the analyses for the Supplemental EA do not address the potential cumulative impacts of multiple pollutants on receptors (including children). As discussed in Appendices D and E of the *Supplemental Environmental Assessment for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental EA) (EPA-821-R-20-002), the benchmark values used in the IRW

Model are based on the toxicity of individual pollutants, and it is beyond the scope of the analysis to examine complex synergistic effects between pollutants and the effects of multiple pollutant interactions on receptors.

One commenter asserted that the analyses for the Supplemental EA do not use site-specific and pollutant-specific discharge data from all affected plants. The Supplemental EA used loadings estimates, developed as described in Section 6 of the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental TDD) (EPA-821-R-20-001), that are reasonably estimated based on average pollutant concentrations (calculated using available data from a subset of plants) and plant-specific discharge flow rates. EPA revised the discussion of limitations and assumptions in Appendix C of the Supplemental EA to acknowledge this limitation more clearly.

30 <u>EA – Downstream Analysis</u>

No comment excerpts were received on this topic.

31 <u>EA – Proximity Analyses</u>

No comment excerpts were received on this topic.

32 <u>EA – Environmental Change Under Regulatory Options</u>

No comment excerpts were received on this topic.

33 <u>Regulatory Implementation – Timing</u>

With respect to timing of the final rule, EPA has made the effort to issue the final rule in time for it to become effective and replace the 2015 rule prior to November 1, 2020.

With respect to the proposed “as soon as possible” date of November 1, 2020, EPA explains in Section VII.D of the preamble why it is postponing this date until one year from publication.

With respect to the latest availability timing, EPA agrees in part and disagrees in part with comments on these latest dates. First, EPA determined that finalizing the proposed December 31, 2025 “no later than” date for FGD wastewater was appropriate as discussed in Section VII.D of the preamble, and disagrees with comments suggesting that longer or shorter timeframes are necessary or appropriate. With respect to longer timeframes, EPA understands that much of the initial planning, water balance studies, and engineering design work necessary for FGD wastewater treatment system upgrades has already been done as a result of the 2015 rule. As discussed in the Supplemental TDD, individual power plants should not have difficulty meeting this date. Even industry-related comments suggest that longer timeframes are suggested primarily as a method for reducing costs. These facts provide strong evidence that a five-year window (combined with the additional flexibility of an eight-year VIP) will be sufficient for the industry to meet the applicable FGD wastewater BAT limitations. With respect to shorter timeframes, EPA disagrees that the statute compels a three-year compliance window. EPA interprets the Act to speak to a 1989 deadline and up to three years for an effluent guidelines rule promulgated prior to 1989. Section 301(b) "Timetable for Achievement of objectives" states: "as expeditiously as practicable, but in no case later than three years after the date such limitations are promulgated under section [304(b)] of this title, and in no case later than March 31, 1989." This language provided up to three years for effluent guidelines promulgated before 1989; but is silent as to the compliance date for any rules promulgated after 1989.

The U.S. Court of Appeals for the Fifth Circuit agreed with EPA's approach in upholding the steam electric postponement rule. It held:

> EPA's reading of the text accords the language its natural meaning: the initial BAT effluent limitations were to be complied with as expeditiously as practicable, but in no case later than three years after promulgation, with a final compliance date of March 31, 1989 at the latest. Regulated parties had to comply with EPA's initial BAT effluent limitations either within three years of promulgation or by March 31, 1989 – whichever came first. This reading is supported by § 1311(d), which requires EPA periodically to review BAT limitations, including after 1989, but contains no such compliance deadline. See 33 U.S.C. § 1311(d) ("Any effluent limitation required by paragraph (2) of subsection (b) of this section shall be reviewed at least every five years and, if appropriate, revised pursuant to the procedure established under such paragraph."). And Petitioners must concede that, contrary to their argument, even the 2015 Rule allowed for compliance dates later than three years after it first took effect.

Clean Water Action v. EPA, 936 F.3d 308, 316-317 (5th Cir. 2019).

Since EPA is not statutorily constrained by a three-year compliance window, the Agency turns to commenters' asserted factual basis for suggesting a shorter timeframe. While the availability of the VIP certainly does provide power plants additional flexibility, and may alleviate some vendor capacity issues, the Agency estimates that only eight power plants would choose to participate in the VIP. Thus, in establishing a "no later than" date for FGD wastewater, vendor capacity should conservatively be judged assuming that all power plants will adopt the generally applicable CP+LRTR technology. In meetings that EPA had with electric utilities and third-party EPC firms, both conveyed that after the 2015 rule vendors were declining to bid on projects due to vendor production capacity constraints. While production may have increased during this rulemaking, EPA has not received any evidence in the record that it has increased to the point that every power plant discharging FGD wastewater could upgrade its treatment by 2023. Furthermore, commenters suggesting this shorter timeframe should bear in mind that permitting authorities are still under an obligation to determine a date which is "as soon as possible." Thus, to the extent that supply constraints turn out to be overstated, actual permits are expected to include earlier compliance dates than the 2025 "no later than" date.[79]

Second, EPA determined that finalizing the same December 31, 2025 "no later than" date for BA transport water is warranted. EPA agrees that harmonization across wastestreams and with the CCR Part A rule warrant a change in the latest availability timing for BA transport water. Thus, as discussed in Section VII.D of the preamble, EPA is finalizing a "no later than" date of December 31, 2025. EPA disagrees with the commenters' other rationale for suggesting the 2025 timeframe for BA transport water. Comments relating to incomplete vendor timeframes cite to additional required activities such as conducting engineering studies and raising capital. For BA transport water, these types of activities will to a great extent already be completed by April 2021 to ensure compliance with the CCR Part A rule at the vast majority of plants. With respect to spacing of outages at one or more units to install the control technology, EPA rejected this argument in *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments* (EPA-HQ-OW-2009-0819-6469) after considering the frequency and duration of outages compared to the typical tie-in times for BA conversions demonstrated in the record, and nothing has been added to the record that would change this finding. Similarly, the mere presence of multiple EGUs would not necessarily require additional time for the full system to be operational. For example, a remote MDS has a common drag chain and trough (and where necessary, a chemical addition system or clarifier). These common components make up a substantial portion of the remote MDS equipment, and the fact that piping and remaining equipment might require installation at each EGU would not substantially alter the projected timeframe for installation beyond that caused by the outage schedule. EPA also disagrees that there are only two vendors available to assist all affected plants with compliance with the final rule. EPA notes that there are three vendors with substantial U.S. installation capacity in the record.[80] Furthermore, since the 2015 rule, the number of systems that continue to rely on surface impoundments has decreased from approximately half of the impacted power plants with BA transport water at the time of the 2015 rule to approximately a quarter of those same power plants today. Furthermore, due to the newly created subcategories in the final rule, some of the remaining power plants will not need to convert away from surface impoundments. Commenters make a similar claim with respect to the limited capacity of local labor markets. This claim relied upon full employment market conditions which are no longer current, and thus no further response is necessary. EPA also disagrees that the scrubber exemption for BA transport water warrants a 2025 date. FGD wastewater limits do apply to the wastewater leaving the FGD scrubber; however, EPA has clarified that BA transport water used in the FGD scrubber becomes FGD wastewater, and thus whatever limits apply at the time will apply to that wastewater. In other words, if a permitting authority determines that BA transport water limits should receive an "as soon as possible" date earlier than the FGD wastewater "as soon as possible" date, the BA transport water can still be

[79] Commenters argue that permitting authorities too often default to the latest compliance dates; however, EPA's record demonstrates a mix of compliance dates from the earliest "as soon as possible" date of November 1, 2020 until the "no later than" date of December 31, 2023.
[80] A foreign fourth vendor in the record has a limited U.S. presence but is also a possible vendor for this equipment.

sent to the FGD scrubber as makeup water and meet current TSS limits until the later, more stringent FGD wastewater limitations in that permit go into effect. EPA also agrees that submerged grinder conveyors and other compact submerged conveyors (CSCs) might take longer timeframes and potentially longer outages to install. The one CSC in EPA's record was completed in less than four years; however, commenters provided a timeframe for a CSC project in the southern U.S. that would take four years. EPA has found that harmonization of BA transport water and FGD wastewater timeframes to 2025 is warranted, and plants requiring four years to install a dry handling technology would not be precluded from doing so based on the final availability timing. Similarly, to the extent that harmonization of the dates provides until 2025, permitting authorities may not need to reopen permits within the standard five-year window.

Third, EPA disagrees with the miscellaneous comments about availability timing being too long in general. The eight-year timeframe some commenters lamented in comments on the 2019 proposal is the same eight-year timeframe contained in the 2015 rule, a timeframe which these same commenters did not challenge in *SWEPCO*. Only EGUs opting to voluntarily accept more stringent limits would get this eight-year timing, and this additional time is the main incentive to encourage the adoption of more stringent technologies. Finally, comments that permits in this industrial sector are often expired is a red herring. While it is true that some may be expired and administratively continued, EPA has also been presented with many permits that have been timely issued, even with the prospect of permit modifications potentially necessary as a result of this rulemaking process. Furthermore, the question relevant to this rule is not when permits can and should be issued, but when power plants can feasibly install technologies to comply with these final limitations. EPA has established these timeframes as "no later than" dates, but has allowed the permitting authority the discretion to determine dates as soon as a year from publication, and the lone exception for the VIP is an incentive for plants to install a technology that EPA has not found nationally available at this time. For further discussion of EPA's rationale establishing the availability timing in the final rule, see Section VII.D of the preamble.

With respect to PSES, EPA disagrees with most of commenters' suggestions. The CWA states "Pretreatment standards under this subsection shall specify a time for compliance not to exceed three years from the date of promulgation." CWA section 307(b). Thus, the statutory text precludes harmonization of BAT and PSES outside this three-year window. While this does compress the time after publication that municipalities will have to comply, this will not make these municipalities "front-line" adopters. As discussed in the record, some power plants have been operating high recycle rate BA systems since as early as the 1970s. Similarly, for FGD wastewater CP, LRTR, HRTR, and thermal systems are currently in operation domestically. Thus, other plants have already done the front-line adoption that the commenter is concerned with. The individual power plant study identified by one commenter also does not support that additional time is necessary. While that study identified several technologies and management alternatives that would require additional time, the timeframe presented for utilizing the facility's existing thermal system falls within the three year statutory PSES window, and no other indirect discharging power plants are projected to require treatment upgrades for FGD wastewater under the final rule.[81] EPA also disagrees that it should postpone issuing revised PSES. In having the court hold litigation on BA transport water and FGD wastewater in abeyance, EPA has consistently represented that it can complete reconsideration of BAT and PSES in 2020. Further, this rule updates rules that were last issued (before 2015) in 1982. Given EPA's representations that it can complete reconsideration in 2020, the technology-forcing nature of these provisions of the CWA, and the Agency's ability to finalize, the Agency finds no reason to postpone finalization of PSES. In contrast to the other suggestions, EPA concluded the final rule adequately addresses the timeframe for repowering considerations because the subcategory for boilers permanently ceasing coal combustion by 2028 explicitly provides time for EGUs to convert fuels.

With respect to permitting authorities, EPA disagrees that many of the commenters' suggestions are necessary. Permitting authorities are already authorized to consider the integrated resource plan (IRP) process as an "other" factor under 423.11(t)(4), and it would be an unnecessary consideration for profitable power plants which operate at a high capacity utilization rating. Instead, it is incumbent upon the permittee to request that the permitting authority consider the IRP process and provide clear, relevant information to the permitting authority on the date by which a technology would become available. Comments asking EPA to specify how permitting authorities should determine new dates either with or without a permit modification request are also unnecessary. In cases where there is no permit modification request, permitting authorities may determine that a modification of dates is unnecessary.[82]Clarifications of the defaults recommended by commenters are unnecessary. EPA has postponed the earliest compliance dates to one year from publication making direction regarding the November 1, 2020 date irrelevant and the text of 42311(t) already indicates that the rule is applicable "as soon as possible." Additionally, EPA has determined that a December 31, 2025 "no later than" date is appropriate, and therefore instruction regarding a 2023 date is unnecessary. In contrast, EPA agrees that the proposed requirement for "site-specific" information was too narrow and would have precluded the use of relevant process information developed for other sites. Thus, for the final rule EPA is including the term "site-relevant" information to make clear that while information may be provided from other sites, that information must still be relevant for demonstrating the timeframe by which a technology would become available at the power plant being permitted.

34 Regulatory Implementation – Voluntary Incentive Program (VIP)

Technology Basis and Technologies for VIP

As described in the preamble, the final rule establishes a voluntary incentive program (VIP) with BAT limitations applicable to discharges of pollutants found in FGD wastewater. The VIP includes effluent limitations for arsenic, mercury, nitrate/nitrite as N, selenium, bromide, and total dissolved solids (TDS) based on membrane filtration with chemical pretreatment (see

[81] The system was originally purchased to meet water-quality based boron limitations and the plant has since met those limitations through mixing at the nearby POTW at a cost of approximately $1 million per year.
[82] See response to code 9 (Subcategorization – General).

section VII.B.3 of the preamble for a discussion of the rationale for selecting this as the basis for VIP). For plants opting into the VIP, BAT limitations based on membrane filtration must be achieved by December 31, 2028. See section XIV.A of the preamble for a discussion of timing for the VIP limitations and standards in the final rule.

Some commenters suggested that alternative technologies should be used to establish the VIP limitations. EPA disagrees and notes that final rule does not preclude the use of any specific technology(ies) or require that specific technology(ies) must be used. Steam electric power plants opting into the VIP may use any treatment technology, or combination of treatment technologies, to achieve the effluent limitations described in 40 CFR 423.13(g)(3)(i), including but not limited to thermal treatment (spray dryers, brine concentration, adiabatic evaporation technologies) or zero liquid discharge, any combination of membrane filtration and thermal treatment, or other emerging technologies.

As described in section VII.B.3. of the preamble, the paste technology mentioned by commenters is one option for managing the resulting brine after use of membrane filtration technology; however, EPA did not use this option in its primary cost analysis of the membrane filtration technology basis evaluated for VIP. Rather, EPA costed the membrane filtration technology option to include disposal of the resulting brine using encapsulation technology. As explained in the preamble, where plants might opt to be bound by membrane filtration-based limitations, EPA found brine encapsulation to be the least cost-method available to plants. See section VIII.B of the preamble and the response to Code 17 (FGD Wastewater - Membrane Filtration) for further discussion on EPA's analysis of brine disposal.

EPA agrees with commenters who stated that plants need time to research, select, design, get regulatory approval, procure, install, commission and optimize any new technology, and they may need time to conduct pilot tests of either treatment technologies or brine disposal methods and/or perform analyses to determine the most appropriate approach for each site. The later compliance date for the VIP allows for both technology development and for plants to conduct these studies, approvals, installations, optimizations, etc.

EPA disagrees with commenters who asserted that the Agency's prediction that some facilities will opt into the VIP means that "membrane filtration . . . must be considered BAT and required across the industry." This final rule establishes, for the entire industry (except for some carefully defined subcategories), the best available technology economically achievable (BAT) for control of discharges found in FGD wastewater as chemical precipitation followed by low residence time reduction (CP+LRTR), as described in section VII of the preamble. The VIP simply gives plants the option to be bound by limitations based on more advanced treatment of FGD wastewater (using membrane filtration technology) and allows more time for plants to implement such a treatment alternative. At this time, given the fact that no full-scale membrane filtration systems are currently operating in the U.S. to treat FGD wastewater, the lack of operating and long term performance data for those operating at foreign plants, as well as the NWQEIs associated with disposal of the resulting brine, EPA cannot conclude that this technology would constitute BAT for the entire industry. Although EPA proposed to conclude that membrane technology would be nationally available in 2028, some commenters asserted that it is inappropriate for EPA to predict a date in the future when a technology will become nationally available for CWA purposes. EPA agrees with these commenters and in the final rule concludes only that membrane technology will likely be available by 2028 on a site-specific basis.

VIP Projections/Population and Timing

EPA disagrees with commenters who claim that EPA has provided no explanation of its methodology for projecting who may enroll in the VIP or that EPA's projection is based on "pure speculation." As described in section VII.B.3 of the preamble and in Section 3.1.5 of EPA's *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-003) (BCA Report), EPA's analysis projects that eight plants discharging FGD wastewater will opt into the VIP in the final rule (as opposed to 18 plants that EPA estimated would opt into the VIP under the proposed rule. As described in the BCA Report, this is based on the estimated costs of FGD treatment technologies. EPA compares the estimated costs incurred by a plant to install CP+LRTR treatment (the BAT technology basis) and membrane filtration (the VIP technology basis). Taking into account the timing of these installations based on permit cycles and the implementation requirements described in section XIV.A.1 of the preamble, EPA estimates that, where it is less costly for a plant to install membrane filtration compared to CP+LRTR, these plants would do so. EPA expects that some plants will select the VIP option, as three plants have already elected to participate in the 2015 ELG VIP (DCN SE08700). While EPA acknowledges that the specific plants EPA estimates would opt into VIP may not ultimately do so, EPA considers this least cost treatment technology methodology to be a reasonable estimate of the number of plants that are likely to opt into the VIP.

For the final rule, where a plant indicated in public comments on the proposed rule that they would not opt into the VIP, EPA removed them from the VIP population regardless of EPA's estimated costs for CP+LRTR compared to costs for membrane filtration. As an example, comments from Tennessee Valley Authority (EPA-HW-OW-2009-0819-8458-A1) indicated that Kingston and Paradise would not opt for membrane filtration. As such, EPA removed these facilities from its analysis of VIP plants and does not reflect either plant as opting into VIP under any regulatory option. Regarding commenters claims specifically about Santee Cooper's Cross and Winyah plants, Santee Cooper's comments on the proposed rule (EPA-HW-OW-0819-8322-A1) indicate that they have "not evaluated that technology and did not contribute any site-specific information to EPA's evaluation." Since the proposal, Winyah has announced plans to retire or convert to non-coal fuel prior to December 31, 2028 and so is not included in the VIP analysis. Additionally, based on its updated cost estimates, EPA predicts that the least option for Cross is to select CP+LRTR rather than opt into the VIP. See the Generating Unit-Level Costs and Loadings Estimates by Regulatory Option memorandum (DCN SE08638) for details on which specific plants EPA estimates would participate in VIP.

EPA disagrees with one commenter who suggested that the VIP encourages plants "to simply wait for more and more lenient regulations." The VIP requires achievement of more stringent limitations in exchange for a later compliance date. Effluent limitations guidelines rules like this one, including with the VIP, actually respond directly to the same commenter's request that "the government should incentivize innovation" by establishing limitations and standards and allowing plants to meet those requirements using any technology or control method they choose. And under the CWA, which prescribes a 5-year permit term, NPDES permits must include the technology-based effluent limitations promulgated here, so facilities will have to commit to the effluent limitations path, either BAT or VIP when their next permit is issued.

EPA disagrees with commenters who asserted that the Agency has relied on "voluntary surveys and data." See Section 2 of the *Supplemental Technical Development Document for Final revisions to the Effluent Limitations Guidelines and standards for the Steam Electric Power Generating Point Source Category* (Supplemental TDD) and Section 3 of the 2015 Rule TDD. In particular, the Questionnaire for the Steam Electric Power Generating Effluent Limitation Guidelines (Steam Electric Survey) and a smaller 2018 data request from nine steam electric power companies owning plants that generate FGD wastewater were administered under CWA Section 308 , and as such all facilities receiving the survey were required to respond. Section 308 information requests are enforceable requirements under the Act. See CWA Section 309(a). Also, regarding sampling data, EPA used a combination of data from various different sources in its analyses, including voluntary sampling, EPA sampling data, data from plants and vendors, sampling data from studies and other research, and permit data. These various sources are described in the Supplemental TDD and the 2015 TDD. All available data were evaluated based on a specific set of criteria for which it was to be used (e.g., pollutant loadings, pass-through analysis, effluent limitations, etc).

EPA disagrees with some commenters' assertions that, by establishing the VIP, EPA has "ignore[d] the purpose of the Act," the requirement that BAT limits be achieved "as expeditiously as practicable," or the "requirement for regular review of ELG's adequacy." The statutory requirement cited by the commenter concerning compliance with BAT limitations as "as expeditiously as practicable" (33 U.S.C. 1311(b)(2)(C), (D), and (F)) does not apply to post-1989 rules (see comment response to comments in code 1 (legal)). Additionally, EPA's decision to establish a VIP does not violate a requirement for regular review of ELGs under 33 U.S.C 1311(d) because EPA continues to undertake review of ELGs under its CWA Section 304(m) planning process. The five-year review schedule described in Section 301(d) of the Act does not in any way restrict EPA's authority to establish compliance deadlines that may be achievable in the future on a site-specific basis. See section VII.B.1 of the preamble for a discussion of why membrane filtration was not selected as the generally applicable BAT technology basis for control of pollutants in discharges of FGD wastewater and section VII.B.3 for details on why this technology was selected as the basis for VIP BAT limitations.

EPA disagrees with one commenter's claim that no power plants chose to participate in the VIP established in the 2015 final. Additionally, EPA disagrees that plants do not view the additional compliance time as an incentive for opting into the VIP. EPA is aware of at least three GenOn plants that elected to participate in the 2015 VIP (DCN SE08700). In discussions with the operating company, EPA learned that one of the reasons for selecting this option was the incentive of additional compliance time (DCN SE08614). In addition to the three plants operated by GenOn cited above, EPA is aware of at least one other plant selecting VIP under the 2015 rule (EPA-HQ-OW-2009-0819-8459-A1). Also, as described in section IV of the preamble, EPA determined that it would reconsider the 2015 rule in 2017, and the 2015 rule requirements for FGD wastewater were subsequently postponed as EPA conducted this reconsideration. As such, it is likely that plants have been waiting to decide on their compliance strategies until after seeing this final rule.

EPA disagrees with the commenter who asserted that the VIP option allows plant operators to make an end-run around effluent limits by claiming they will meet stricter standards later. Plants opting into the VIP must meet the specific limitations of section 423.13(g)(3)(i), as well as the reporting and record keeping requirements of sections 423.19(h) and (j). These new requirements include a notice of planned participation which includes a detailed engineering dependency chart in paragraphs (h)(1) and (h)(2), annual progress reports which include a discussion of the interim milestones reached toward achieving VIP limitations by December 31, 2028 in paragraphs (h)(3) and (h)(4), and notification of any material delays in paragraph (j). This regular reporting and additional detail allows the permitting authority to hold facilities accountable, and cases of noncompliance with either the effluent limitations or the reporting and record keeping requirements would be subject to the same penalties as noncompliance with the generally applicable limitations. See Section XIV.B of the preamble for a further discussion of reporting requirements to certify participation in the VIP.

EPA disagrees with commenters who assert that the Agency has not explained, consistent with its record, why the deadline for compliance with VIP limits is established as December 31, 2028. As described in section VII.B.3 of the preamble, the 2028 timeframe is based on the amount of time necessary to pilot, design, procure, and install both the membrane filtration systems and the brine management systems, including disposal capacity. Moreover, while EPA agrees that some plants opting into the VIP may be able to install the technology sooner, part of the incentive for the program, is the extra time provided to achieve compliance. A commenter noted that, in its economic analysis for the proposed rule, EPA estimated that “fifteen of the eighteen facilities it anticipates participating in the VIP would find membrane technology to be the least costly option if the agency established a VIP compliance date of 2025,” however these dates are only meant to be reasonable estimates and are not determinative of when a plant will install the necessary technology to comply with the VIP and are not used in EPA’s determination of the deadline for compliance with VIP limits. Finally, EPA notes that this timeframe is also similar to the eight-year period between promulgation of the 2015 rule and the 2023 deadline for the 2015 rule’s VIP.

As was the case for the proposed rule, the final rule does not include a section 423.13(g)(3)(ii). This rulemaking was intended only to address the new, more stringent limitations and standards established in the 2015 rule applicable to discharges of pollutants in FGD wastewater and BA transport water from existing sources. Thus, discharges of pollutants found in FGD wastewater generated before December 31, 2028, for plants enrolled in the VIP are outside the scope of this rulemaking. As indicated in the preamble, EPA intends to undertake a separate action related to combustion residual leachate and legacy wastewater.

35 Regulatory Implementation – Compliance Monitoring

While EPA agrees with the commenters who asserted that "changes in wastewater flows or concentrations can affect the microbes, which must acclimate to each change" in a biological treatment system, EPA does not agree with these commenters that this precludes selecting biological treatment as part of the BAT technology basis for controlling pollutants found in FGD wastewater. As discussed in response to the 2015 rule, the data in the record demonstrate that these challenges can be overcome and do not result in difficulties achieving treatment. As part of the 2015 rule, EPA gathered information regarding how biological systems can continue to operate by recirculating water and adding additional chemicals to maintain microbial health. As discussed in *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments* (EPA-HQ-OW-2009-0819-6469), specifically EPA's response to EPA-HQ-OW-2009-0819-4655, Excerpt Number 107, cites details from a vendor of high residence time reduction (HRTR) technology regarding many cases in which anaerobic systems run on seasonal industrial operations and see shutdowns for as long as 6 months. In order to maintain the bacteria, a small amount of feed water (with some nutrient added) once per week can be supplied to the biological reactor. The biomass can remain in a less active (nearly inactive) state for long periods of time and resume normal metabolic function in a relatively short time once wastewater is available again. If back-up power is available, a constant recycle through the system can also be done, but it is not a necessity. The biological treatment system can quickly return to operation if proper maintenance of the microbiology occurs during shutdowns. Commenters provided no new evidence to support the claims that cycling adversely impacts treatment effectiveness; and none of the new data collected as part of EPA's reconsideration of the 2015 rule support the commenter's claims. As described in Section 4 of the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001) (Supplemental TDD), HRTR biological treatment and the technology selected as the basis for best available technology economically achievable (BAT) requirements, low residence time reduction (LRTR) biological treatment, utilize the same treatment mechanism. For this reason, and because EPA has obtained no additional information since the 2015 rule on the impact of cycling and biological treatment, EPA retains its conclusions from 2015 regarding this topic.

Additionally, the record includes data for three coal-fired steam electric power plants operating biological treatment systems: Duke Energy's Allen and Belews Creek Stations and American Electric Power's (AEP) Mountaineer Plant. The data reflect treatment system performance over a period of two years at one plant, and more than four years for each of the other plants. Both baseload and cycling power generation operations are included in the data as well as steady power output, increasing and decreasing power output, shutdown and restart of one or more generating units at a site, and complete plant-wide shutdown followed by restart of one or more generating units. EPA evaluated effluent data against short-term or extended shutdown periods.

See Attachment A from *Memorandum Variability in Flue Gas Desulfurization Wastewater: Monitoring and Response* (EPA-HQ-OW-2009-0819-6033) for the full evaluation of plant and treatment system shutdown periods on effluent selenium. These data do not indicate any significant relationship between changes in capacity, a unit being shut down in the previous period, or the percentage change in capacity generated and the plant's ability to treat wastewater with fluctuations in selenium concentration. Based on these data, it cannot be concluded that shutdowns, or large changes in generation, are related to selenium concentrations above the ELG effluent limitations.

Regarding comments related to pilot data used to establish limitations for flue gas desulfurization (FGD) wastewater, including which data was excluded due to being representative of prior to steady state operation or considered treatment system upsets or abnormal operation for the final rule, see responses to Code 43 (numeric limits).

EPA disagrees with the commenter who asserted that a "lack of online, real-time monitors for selenium and mercury" in the industry result in insurmountable difficulty with meeting the limitations established in the final rule. Online selenium and mercury monitors are not a requirement of the chemical precipitation followed by low residence time reduction (CP+LRTR) treatment system; as such, EPA has not included costs for these monitors in compliance cost estimates. EPA has included traditional compliance monitoring costs and costs for a mercury analyzer in the cost estimates for the CP+LRTR system. As described in the *Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology* (document control number (DCN) SE08594), EPA used 2015 data to generate cost curves for chemical precipitation (CP) pretreatment costs. As noted in the *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-15-007) (2015 TDD), the 2015 rule accounted for capital and operating and maintenance costs associated with a mercury analyzer as part of the CP system. The limits are based on data from plants operating these systems over a period of time and include a variability factor. See section XIII of the preamble and the 2015 *Statistical Support Document: Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Final Steam Electric Power Generating Effluent Limitations Guidelines and Standards* (DCN SE05733) for a detailed explanation of the variability factor and calculation of limitations**.** Additionally, plants may also choose to monitor pH and oxidation reduction potential throughout the scrubber and within the chemical precipitation system as a method of monitoring treatment system performance. Monitoring pH can help inform chemical addition rates which can be adjusted upstream of the biological reactors (as part of the chemical precipitation system) to provide optimum conditions for microbial health and selenium reduction in the bioreactors. Monitoring oxidation reduction potential downstream of the bioreactors can inform adjustments to the nutrient feed. See Section 7.1.3 of the 2015 TDD for additional discussion on how plants can implement a proactive oxidant monitoring and mitigation strategy for biological treatment.

Some commenters suggested EPA include effluent limits for bromide in the final rule. EPA is not establishing limitations based on bromide levels occurring in coal or in additives. As noted in

Section XIV.C of the preamble, EPA is not finalizing additional limitations on bromides of FGD wastewater beyond the removals that might be accomplished by plants choosing to participate in the VIP. See section XIII.A.4 of the preamble and Chapter 8 of the Supplemental TDD for further detail regarding the calculation of effluent limitations established for FGD wastewater. As described in Section 6 of the Supplemental TDD, EPA evaluates bromide concentrations using a separate methodology, which are impacted by coal or coal additives, as part of its pollutant loadings estimates. See section XIV.C of the final rule preamble for a discussion of EPA's rationale and further guidance on bromides.

36 Regulatory Implementation – Bromide

EPA agrees that the examples provided by commenters demonstrate site-specific impacts from bromide discharges that warranted further action at those locations; however, EPA disagrees with commenters' assertion that these individual issues warrant nationwide regulation. Instead, EPA concludes in sections VII and XIV.C of the preamble that, given EPA's decision that BAT for control of pollutant discharges in FGD wastewater is chemical precipitation plus low residence time biological treatment and BAT for control of pollutant discharges in bottom ash transport water is a high recycle rate system, potential bromide discharges are best addressed using site-specific, water quality-based effluent limitations established by NPDES permitting authorities for the small number of steam electric power plants that may impact downstream drinking water treatment plants. Such an approach allows the permitting authority to tailor any monitoring or other requirement to the watershed and plants at issue, avoiding many of the individual concerns raised about specific monitoring programs. As discussed in Section VII.B.1 of the preamble, EPA has concluded that CP+LRTR is the generally applicable BAT. This BAT technology basis does not control bromide, and therefore EPA has appropriately not established bromide limitations. However, bromide would be controlled at power plants that choose to participate in the VIP. EPA selected membrane filtration as the technology basis for the VIP and because this technology controls bromide, EPA has appropriately included bromide as a regulated pollutant for power plants opting into the VIP limitations.

EPA disagrees with commenters who asserted that a combination of nationally applicable sub-options is the minimum the Agency should do. As described in Chapter 4 of the *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA Report) (EPA-821-R-003), estimated changes in downstream bromide concentrations associated with changes in bromide discharges from steam electric power plants are concentrated at a small number of sites. EPA's analyses support its determination that potential bromide discharges are best addressed using site-specific, water quality-based effluent limitations established by NPDES permitting authorities for the small number of steam electric power plants that may impact downstream drinking water treatment plants. Such an approach allows the permitting authority to tailor any monitoring or other requirements to the watershed and plants at issue. Some commenters argued that interstate waters can transport bromides across state lines and the final rule must regulate bromide discharges. These commenters failed to explain, however, why they believe that WQBELs cannot address cross-state water quality issues. Permitting authorities have previously addressed cross-state water quality issues. To the extent that permitting authorities have questions about implementing such cross-border water quality approaches, EPA further discusses the issue in *Protection of Downstream Waters in Water Quality Standards: Frequently Asked Questions*.[83]

The final rule is consistent with comments that supported a strong WQBEL program for addressing bromide. Those commenters were skeptical of a nationwide approach and noted that permitting authorities are already required to ensure that discharges will meet all water quality criteria, including narrative water quality criteria, through permits they issue. Commenters also noted that the Broad River example demonstrates that a site-specific approach can work and has worked in practice.

EPA disagrees with commenters who suggested that monitoring should be required in all NPDES permits issued to steam electric power plants. While EPA agrees that monitoring is a necessary tool where actual or potential downstream impacts are identified, the states that EPA identified as requiring bromide monitoring demonstrates that permitting authorities have the legal authority to require necessary information and in many cases already exercise that authority.[84] The Agency continues to be supportive of monitoring efforts permitting authorities might take to better understand the fate and transport of pollutants in their particular watersheds.

At proposal, EPA solicited comment on three sub-options that could be developed further to help address potential bromide discharges. Some commenters noted that the sub-options would not address bromide naturally occurring in the coal. EPA agrees and reiterates that, given the site-specific factors that influence potential downstream effects of bromide discharges, the most appropriate management tool is through the development of WQBELs for a NPDES permit.

At proposal EPA solicited comment on data that the Agency could use to establish a bromide limitation based on the substitution of refined coal or other bromide additions with another product. EPA received no such data during the public comment period, and the limited data EPA possessed at proposal have overlapping ranges between discharges at plants burning coal with bromide addition and discharges at plants burning coal without bromide addition. In other words, some of the power plants adding bromide may have lower bromide concentrations in effluent discharges than power plants burning coal without bromide addition. Thus, it is not possible to set a limitation based on coal or additive substitution.

EPA also solicited comment on whether the final rule should include a nationwide requirement that all plants develop and implement a bromide minimization plan. Commenters were split with some supporting and others not supporting a nationwide requirement for bromide minimization

[83] U.S. EPA (Environmental Protection Agency). 2014. *Protection of Downstream Waters in Water Quality Standards: Frequently Asked Questions*. EPA-820-F-14-001. Office of Water. June. Available online at: *https://www.epa.gov/sites/production/files/2018-10/documents/protection-downstream-wqs-faqs.pdf*

[84] Some comments provide further statements that nearly 50 percent of power plants discharging FGD wastewater have required bromide monitoring which. Though EPA was not able to verify all of these monitoring requirements, it provides further support to EPA's conclusion that permitting authorities can, and do, require monitoring when they identify potential water quality issues.

plans. EPA received comments that a plant could potentially reduce its bromide discharges by switching the type of coal burned at the plant or altering the kinds of additives used with the coal burned. However, as noted above concerning product substitution, the type of coal burned and the use of additives are not necessarily determinative of whether and to what extent bromides may be in effluent discharges. Unlike treatment technologies which can be installed once and operated for their useful life, as commenters explained, many aspects of plant operations, including type of coal burned or additives used, change daily, if not more frequently. Some commenters asserted that prohibitions or regulations on the use of bromide may lead power plants to substitute with iodine or other additives, which may also have the potential for adverse impacts. See further discussion in Section 2.1.3 of the Supplemental EA. As described throughout the preamble and supporting documents, EPA has concluded that water quality-based effluent limitations (WQBELs) are the appropriate mechanism for addressing bromides (and iodine). With respect to an approach which would allow power plants to work with downstream drinking water utilities to upgrade drinking water treatment systems, nothing in the final rule would preclude cooperative efforts between facilities to address site-specific issues that may arise due to bromide discharges. To the extent that bromides can be addressed on a site-specific basis using water quality trading or other market-based mechanisms, EPA is supportive of creative solutions that can improve water quality and address downstream issues. See response comment code 37 for further discussion.

Finally, with respect commenters request that EPA prohibit the use of iodine and other additives, for many of the same reasons noted throughout this response to comment document, the final rule does not include such a prohibition. EPA's rulemaking record contains very limited information about iodine, and publicly available data is more limited and uncertain than data on bromide. However, in response to comments, EPA conducted a mass balance to estimate iodine loadings based on the limited available data. For a more complete discussion of these changes, see Section 6 of the Supplemental TDD.

37 <u>Regulatory Implementation – Other</u>

EPA supports a number of existing trading projects involving nutrients, and supports water quality trading generally where consistent with Federal and State law. EPA did not propose and is not including pollutant trading as an alternative to meeting the requirements in the final rule.

EPA did not establish a trading mechanism in the final rule in part because it would have wanted to solicit public comments on such a proposal and fully evaluate those comments before establishing it in effluent guidelines rulemaking for the first time.

With respect to commenter's suggestion that professional engineer (PE) certifications are unnecessary, EPA disagrees. Unlike the administrative reporting requirements of paragraphs 40 CFR 423.19(e)-(j) which may be certified to by a "responsible corporate officer" as provided for in 40 CFR 122.22, the BA transport water certifications required in paragraphs (c) and (d) are very fact intensive, and are appropriately designated to the specific expertise of a licensed PE.

These provisions in the final rule are consistent with similar fact-intensive PE certifications required in the final CCR Part A rule.

With respect to comments about reuse of BA transport water in the FGD system, EPA disagrees that sending BA transport water to the FGD system after the absorber would be reuse. While the 2015 rule exemption in §423.11(p) for use as FGD makeup water is a distinct reuse of transport water because it replaces alternate sources of water that might otherwise be required (i.e., groundwater or surface water) and therefore would have indirect environmental benefits (e.g., reduced impingement/entrainment), the suggested use in any downstream portion of the FGD system would merely be treatment, and not reuse, as no alternate water source is being replaced, and none of the associated benefits of reducing that water use would occur. Nevertheless, EPA agrees that these wastewater treatment systems might be appropriate for treating BA purge water, and thus now requires that power plants report these systems under 423.19(c)(3)(H) and (I) so that the permitting authority may properly consider them as part of the required BPJ analysis for BA purge water. As discussed in section XIV.A.2 of the preamble, the appropriate treatment of BA purge water will depend on site-specific purge considerations. To the extent that the commenter also identified potential difficulties in sending BA transport water to the FGD absorber as FGD makeup water,[85] nothing in that portion of the 2015 rule would require that BA transport water be sent to the FGD absorber as makeup water. Furthermore, EPA has clarified in the provision allowing reuse as FGD makeup water in 423.13(k)(1) that this reused water is no longer BA transport water as follows:

> "When the bottom ash transport water is used in the FGD scrubber, it ceases to be bottom ash transport water, and instead is FGD wastewater, which must meet the requirements in paragraph (g) of this section."

Since paragraph 423.13(g) only applies to the discharge of FGD wastewater, the building block approach, an approach used by permitting authorities when wastestreams subject to different limitations are comingled, will not apply as all wastewater will now be considered the same FGD wastewater, and compliance would not require internal monitoring.[86]

With respect to comments that the proposed rule did not require adequate documentation that purges are necessary and that the necessary documentation is unclear, EPA agrees. In the final rule, the purge volume for each plant will be established by the permitting authority using BPJ. Section 423.19(c)(3)(F) of the final rule requires documentation to be provided by the permitting authority, including the expected volume and frequency, and why such volumes cannot be managed within the system under section 423.19(c)(3)(G). Using this information, permitting authorities are to determine a purge volume no greater than ten percent of system volume that is permissible for discharge. As discussed in section XIV.A.2 of the preamble, this purge may be "tiered or differentiated" when multiple types of purges are necessary. This framework also

[85] The statements regarding aluminum fluoride blinding conflict with findings by EPRI that aluminum solubility at the pH in FGD absorbers is lower than the concentrations that would lead to aluminum fluoride blinding.

[86] See Chapter 5 of the *NPDES Permit Writers' Manual*. Available online at: https://www.epa.gov/npdes/npdes-permit-writers-manual

ensures that power plants document why particular purges are necessary such that the permitting authority can minimize these discharges to only the necessary volumes, subject to the 10 percent volumetric cap.

38 Coordination with Other EPA Rules

As described throughout the preamble, EPA agrees with commenters who asserted that harmonization between the ELG and other regulations impacting the steam electric industry is important. There are several aspects of the final rule that allow for appropriate harmonization with other regulations, including the Coal Combustion Residual (CCR) Rule, such as the following:

- The final rule extends the "no later than" date for compliance with flue gas desulfurization (FGD) wastewater best available technology economically achievable (BAT) limitations based on chemical precipitaton plus low residence time reduction (CP+LRTR) to December 31, 2025. See Section VII.D of the preamble for more information.
- The final rule extends the "no later than" date for compliance with the generally applicable bottom ash (BA) transport water BAT limitations to December 31, 2025. See Section VII.D of the preamble for more information.
- The final rule creates a subcategory for electric generating units (EGUs) that permanently cease coal combustion by 2028. See Section VII.C.3 of the preamble for more information.
- The final rule allows for transfer between alternative limitations under 40 C.F.R. 423.13(o).

See the response to comment code 8 (Adjustment for CCR/CPP/ACE Rules) for more information on how EPA accounted for the CCR Rule in its rulemaking analyses. EPA's analyses for this final rule account for plant-specific CCR rule compliance information where it was provided to EPA either in public comments or other communications which are included in the record. For example, Brunner Island is expected to permanently cease combustion of coal by 2023 and thus will not incur any costs under the final rule.

39 Analytical Methods

No comment excerpts were received on this topic.

40 Economics

General Scope and Discussion

EPA details its rationale for reconsidering the 2015 ELG in the final rule preamble and in other parts of the rulemaking record.

While technology-based rules are not based on environmental impacts, EPA disagrees that this rule will negatively affect recreation and industries that rely on clean water. First, EPA notes that the effect of water quality changes on the recreational value of water resources is implicitly included in the total willingness-to-pay for water quality changes, as discussed in Chapters 2 and 6 of BCA. Although the Agency was unable to quantify potential impacts of water quality changes resulting from the rule on other water-dependent sectors (*e.g.*, seafood industry and tourism), EPA assessed these effects qualitatively (see Chapter 2 of BCA for detail). Moreover, the Agency notes that the estimated changes in ambient pollutant concentrations in most waterbodies affected by steam electric discharges are very small compared to (the 2015 rule (baseline) and thus are unlikely to have measurable economic impacts on other industrial sectors (see Chapters 3 and 4 of BCA for detail).

EPA disagrees that using the 2015 ELG Rule as the baseline results in an economic analysis that captures only part of the impact of the final rule. EPA re-estimated the compliance costs associated with meeting the 2015 ELG for the two wastestreams addressed in the final rule and details these costs in the Supplemental TDD (U.S. EPA, 2020). With respect to estimating the economic impacts of the final rule, EPA followed established practice and guidelines and used a baseline that reflects the best assessment of the world absent the final rule, including compliance with existing regulations (Office of Management and Budget, 2003; U.S. EPA, 2010). Given that EPA finalized the previous ELG revisions in 2015 and, in 2017, finalized a postponement of the earliest compliance dates for the BAT effluent limitations and PSES for FGD wastewater and BA transport water, EPA concluded that it was appropriate to use the 2015 Rule as the baseline for this final rule. EPA's analyses incorporate the effects of other existing regulations on steam electric power plants impacted by the rule, including those requirements of the 2015 rule that are not being reconsidered in the final rule. In doing so, EPA did consider the economic impacts of all final rule provisions relative to this baseline.

Section 6 in the *Supplemental TDD* details the basis for, and uncertainty of, the estimated pollutant loadings. EPA's loading estimates are based on the best information available to EPA and EPA has considered any specific suggestions for reducing uncertainty provided by commenters. As such, EPA's analysis is appropriate for presenting loadings and estimating benefits. Neither the costs, nor the pollutant loading estimates prepared by EPA, for the purpose of evaluating various regulatory options, are designed to reflect changes to an industry with exact precision. See BP Exploration & Oil, Inc. v. EPA¸66 F.3d 784, 800 (6th Cir. 1995) ("'The CWA does not require a precise calculation of BAT and NSPS costs.'") (quoting NRDC, Inc. v. EPA, 863 F.2d 1420, 1426 (9th Cir. 1988)); Chem. Mfrs. Ass'n v. EPA, 870 F.2d 177, 237-38 (5th Cir. 1989) ("The Act requires the EPA to 'take into account' the costs of BAT; it does not require a precise calculation. The EPA 'need make only a reasonable cost estimate in setting BAT'; it is sufficient if the EPA develops 'a rough idea of the costs the industry would incur.'") (internal quotations and citations omitted); see also Texas Oil & Gas Ass'n v. EPA, 161 F.3d 923, 936 (5th Cir. 1998) (EPA's effluent reduction estimates were performed "only to satisfy the CWA's unrelated requirement that the EPA 'identify' in its regulations the degree of effluent reduction attainable through the application of BAT . . . As such, even serious flaws in the effluent reduction estimates could not provide grounds for remanding the zero discharge limit.") (citing 33 U.S.C. § 1314(b)(2)(A)).

Costs and Economic Impacts are Understated

EPA disagrees that the RIA underestimates costs and economic impacts of the regulatory options, including the final rule. See Section 5 of the *Supplemental TDD* for a description of EPA's methodology for estimating capital and O&M costs for steam electric power plants to comply with the regulatory options. EPA assessed the economic impacts of the regulatory options on existing units at steam electric power plants in the RIA, following EPA's Guidelines for Preparing Economic Analyses and Office of Management and Budget Circular A-4. The analysis includes both a screening level comparison of compliance costs to plant- and firm-level revenue, and an assessment of the impact of estimated compliance costs for the final rule within the context of the broader electricity market (Office of Management and Budget, 2003; U.S. EPA, 2010).

Based on these analyses, EPA assessed that the final rule will provide savings as compared to the costs that the industry would incur under the 2015 Rule and is economically achievable. EPA made certain changes to the final rule in response to concerns expressed by commenters. See the final rule preamble for full discussion of the final rule and changes from proposal. The final rule includes subcategories for electric generating units (EGUs) permanently ceasing the combustion of coal by December 31, 2028, and low utilization units, defined as units that have an average annual CUR of less than 10 percent per year, averaged over 24 months.

Early Retirements and Repowerings

EPA modified the final rule from proposal in response to concerns expressed by commenters. The final rule includes both retiring and repowering facilities in the subcategory of EGUs permanently ceasing the combustion of coal by December 31, 2028. The analysis of the final rule, which includes all units operating as of December 2019, determined that the final rule will provide savings as compared to the costs that the industry would incur under the 2015 Rule and is economically achievable.

IPM – Industry and Market Impacts

EPA makes ELG determinations based on a number of statutory factors that include, but are not limited to, economic achievability. See Preamble Section IV.B.2 and Comment Code 1 regarding the factors EPA uses to establish effluent limitations that reflect BAT.

For the final rule analysis, EPA considered inputs from commenters and developed a range of regulatory options that include various technologies that can achieve varying pollutant removals (see Supplemental TDD for details). The analysis of these options included an analysis of the economic impacts in the context of regional and national electricity markets. EPA used the appropriate IPM inputs at proposal. EPA continued to use the most current version of IPM to analyze the final rule; however, for the final rule EPA updated its inputs to include the impacts of the DC Circuit Court rulings in *USWAG v. EPA*, No. 15-1219 (DC Cir. 2018) and *Waterkeeper Alliance Inc, et al. v. EPA*, No. 18-1289 (DC Cir. 2019) and CCR Part A final rule (See RIA Chapter 5). IPM estimates that the final rule will result in increased coal capacity for all years from 2021 to 2050, with the increase ranging between 1.0 and 2.0 gigawatts (GW). The additional capacity under the final rule is projected to come from avoided retirements of existing coal units. The final rule is also projected to reduce electricity prices.

Based on these analyses and the factors discussed in the final rule preamble and supporting documents, including the comment responses referenced above, EPA determined that the final rule is economically achievable and the final rule establishes effluent limitations based on Best Available Technology Economically Achievable (BAT), for FGD wastewater and bottom ash transport water.

Impacts on Selected Utilities and Upstream Sector

EPA disagrees with the commenter that the final rule will disproportionately affect municipally-owned plants and the ratepayers they serve. The final rule will provide cost savings relative to the 2015 rule baseline, including for municipality-owned plants.

As part of its economic impact analysis, EPA assessed the impacts to steam electric power plants owned by municipalities, at the level of the plant and the parent entity. At the parent entity level, EPA estimated that zero municipality parent entities would incur annualized compliance costs exceeding three percent of revenue in the baseline or under the final rule (Option A). In doing this analysis, EPA conservatively (i.e., likely overestimated actual plant costs) assumed zero pass-through of compliance costs to consumers to represent a worst-case scenario from the perspective of the plant owner. To the extent that municipalities are able to pass some compliance costs on to consumers through higher electricity prices, this analysis may overstate the potential impact to municipality-owned steam electric power plants and their owners. In addition, EPA assessed the potential impacts of the final rule on electricity prices. For this analysis, EPA assumed 100 percent pass-through of compliance costs to electricity prices to represent a worst-case scenario from the perspective of households. EPA estimated that if all annualized cost savings were passed on to residential consumers of electricity, instead of being borne by the operators and owners of facilities, the average cost savings under the final rule for a residential household is $0.49 per year as compared to the 2015 rule. See Chapter 4 in the RIA for discussion of plant- and parent entity-level impacts of the final rule, and Chapter 7 in the RIA for discussion of the impacts on electricity prices.

EPA has provided a description of the steam electric power generating industry in the 2013 proposed rule, the 2015 rule, the 2019 proposed rule, and has continued to collect information and update that profile for the final rule. See Chapter 2 of the RIA and Chapter 3 of the *Supplemental TDD* for a description of the industry, including discussion of current market conditions in the coal sector and other environmental regulations affecting the steam electric industry.

EPA analyzed the impacts of the final rule in the context of the national and regional electricity markets using IPM. The analysis, which is detailed in Chapter 5 of the RIA, estimates an increase in coal use by the power sector of 0.5 to 1.2 million tons per year as a result of increased coal-fired generation.

Some commenters submitting comments on economic impacts also commented on the ratios of costs to pollutant removals (i.e., cost-effectiveness) in their support of a specific regulatory options. EPA's response to comments on cost-effectiveness can be found in the response to comments in Code 5.

References

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U.S. Environmental Protection Agency. (2010). *Guidelines for Preparing Economic Analyses*. (EPA-240-R-10-001).

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41 Benefits

Benefits Analysis Scope and General Assumptions

EPA notes that the analysis of benefits fulfills the Agency's requirements under Executive Order 12866, but is not a statutory factor for determining technology-based effluent limitations and standards, what is best available technology economically achievable as that term is used in section 301(b) after consideration of the factors specified under section 304(b). *See, e.g., EPA v. National Crushed Stone Ass'n*, 499 U.S. 64, 71 (1980) ("[I]n assessing BAT total cost is no longer to be considered in comparison to effluent reduction benefits."). *See also Am. Petroleum Inst. v. EPA*, 858 F.2d 261, 265 (5th Cir. 1988) ("[A] direct cost/benefit correlation is not required [for BAT], so even minimal environmental impact can be regulated, so long as the prescribed alternative is 'technologically and economically achievable.'") (citation omitted); *Ass'n of Pacific Fisheries v. EPA*, 615 F.2d 794, 818 (9th Cir 1980) ("Congress did not intend the Agency or this court to engage in marginal cost-benefit comparisons") (citation omitted); *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 936 (5th Cir. 1998) ("In applying the BAT standard, the EPA is not obligated to evaluate the reasonableness of the relationship between costs and benefits.") (citing *EPA v. National Crushed Stone Ass'n*, 499 U.S. at 69). The analysis described in the BCA developed for the final rule was not used to "justify" the BAT decisions in the final rule.

In response to comments that expressed concerns that EPA understated forgone benefits and overstated benefits relative to the 2015 rule because of projections EPA made about enrollment in the Voluntary Incentive Program (VIP), EPA disagrees with commenters that stated that projections based on record information used in this analysis are "unjustified," or that the

Agency erroneously accounted for benefits associated with pollutant reductions from adoption of the VIP technologies. Accounting for behavioral response to incentive elements of a regulation is consistent with EPA's Guidelines for Preparing Economic Analysis (U.S. EPA, 2010a). EPA made reasoned determinations in assessing the likelihood of steam electric power plants' participation in the program, as discussed in Section 3.1.5 of the RIA. EPA compared the annualized and discounted cost of implementing technologies that achieve limits based on CP+LRTR between 2021 and 2025, based on the plant-specific technology implementation schedule described in Section 3.1.3 of the RIA, to the cost of implementing membrane filtration in 2028. At proposal, EPA evaluated treatment technologies in place and projected 18 facilities would opt to participate in the VIP program as the costs to do so would be less than installing technologies that achieve limits based on CP + LRTR. For the final rule, EPA re-evaluated this assumption by looking at updated cost modeling outputs, projected closures, and feedback from projected VIP participants and revised the list to 8 facilities. However, EPA acknowledges that these costs and technology selections are projections, and therefore EPA discusses the uncertainty of this estimate in Section 3.3 of the RIA.

EPA disagrees with the comment regarding comparative benefits of the 2015 rule and the 2019 proposal. The commenter does not substantiate the claim that if "forgone benefits were correctly valued, they would likely outweigh the decreased compliance costs associated with the Proposed Rule." The Agency also disagrees with the commenter's claim that a "corrected" benefit cost analysis would demonstrate that "the Proposed Rule is unjustified." As required by the CWA, the final rule is based on the statutory factors specified in sections 301(b) and 304(b). EPA applied these factors in selecting the option it is now finalizing. The factors used in determining BAT are discussed in more detail in Section VII of the preamble for the final rule. The benefit cost analysis is developed pursuant to Executive Order 12866 and OMB Circular A-4 and was not relied upon by the Agency in its selection of BAT. EPA notes that the Agency's BAT decisions reflected in the final rule are not based on a benefits analysis, which EPA conducts pursuant to Executive Order.

EPA disagrees that the analysis of environmental impacts and benefits was based on flawed assumptions. Regarding the existence of forgone benefits, EPA acknowledges that the final rule may increase discharges of some pollutants and decrease discharges of other pollutants, as compared to baseline, and that the direction of effects and benefits is not uniform across benefit categories. EPA estimated forgone benefits from increased IQ losses in children from exposure to lead and mercury, decreased surface water quality (ecological conditions), and market productivity effects. These analyses, which are detailed in the BCA, show that the estimated changes in these metrics are small compared to baseline.[87] Further, EPA estimated small changes in air emissions as a result of projected changes in the profile of electricity generation. Consistent with Executive Order 12866, OMB Circular A-4, and EPA's *Guidelines for Preparing Economic*

[87] EPA did not monetize the benefits of bromide reduction for the final rule and therefore does not include this benefit category in the benefit-cost comparison. The Agency notes that the estimated value of water quality changes, which capture changes in ecological condition, is independent of changes in bromide concentrations.

Analyses, the Agency presents the benefits EPA was able to quantify and/or monetize, as well as discusses qualitatively those benefits that could not be quantified.

The Agency disagrees with the commenter's suggestion that the greatest value of quantified benefits corresponds to the "best" regulatory option. As the preamble discussion makes clear, EPA's decisions on the final rule are based on the factors specified by Sections 301 and 304 of the Clean Water Act – most importantly, the technologies selected in the final rule are "available" and the final rule is "economically achievable" for the industry as a whole. EPA's decisions on the final rule are not based on a benefits analysis, which EPA conducts pursuant to Executive Order. See Code 1 for EPA's response on CWA statutory factors and the appropriate role of benefit-cost analysis in ELG development.

For the final rule, EPA analyzed a regulatory option (Option C) that included attributes suggested by some commenters, including omission of proposed subcategories for high flow plants, low utilization electric generating units, and units retiring by 2028. EPA disagrees with the commenter's assertion that this option is the only "acceptable" option. For the reasons discussed in Section VII of the preamble, the Agency did not select this option as the basis for BAT. As required by the CWA, the final rule is based on the statutory factors specified in sections 301(b) and 304(b). EPA applied these factors in selecting the option it is now finalizing.

EPA agrees with the commenter that the best practices for cost-benefit analysis incorporate or consider all categories of costs and benefits that could be quantified or monetized. EPA's analysis conforms with these best practices. As noted above, the Agency considers both quantified and non-quantified benefit categories in weighing benefits and costs of regulatory options as well as uncertainty inherent in benefit cost estimates. While both benefit and cost values are subject to uncertainties, which EPA discusses in the BCA and RIA, they are based on the best information available to EPA. EPA has also considered specific suggestions for reducing uncertainty provided by commenters, including examination of an alternative slope factor for arsenic and quantification and monetization of human health benefits associated with changes in exposure to $PM_{2.5}$ and ozone. EPA's analysis is appropriate for presenting loadings and estimating benefits.

EPA disagrees with the comment regarding the use of an alternative slope factor in assessing cancer risk from exposure to arsenic via fish consumption. First, as noted in the BCA, EPA reiterates that the Agency has not finalized an alternative cancer slope factor for internal cancers, including bladder and lung (U.S. EPA, 2010b). Therefore, the Agency used the slope factor for skin cancer in its analysis presented in Chapter 5 of BCA. In response to the comments, EPA conducted a sensitivity analysis using EPA's draft slope factor for internal organ cancers. Results of this analysis are presented in a memo provided in the docket "Alternative Cancer Slope Factor and Case Valuation for Arsenic Analysis" (DCN SE09337). As detailed in the memo, using the slope factor for internal organ cancers does not change EPA's benefits estimates given that the estimated forgone monetized benefits are very small.

Regarding comments that the status quo baseline would be current (2019) conditions, EPA disagrees. The appropriate baseline for the analysis should reflect conditions in the absence of any further EPA action, which in this case would be the 2015 rule requirements as well as the September 2017 postponement rule. However, EPA agrees with the comment that argued that the baseline used in the economic analysis for the final rule should also reflect costs to retiring or repowering units. As noted in Section 1.2.2. of the RIA, the baseline for the analyses supporting the final rule reflects the 2015 rule requirements as well as the September 2017 postponement rule, which delayed by two years the earliest compliance dates for the 2015 rule applicable to FGD wastewater and bottom ash transport water (in absence of the final rule). The analysis of the final rule includes EGUs expected to be operating after December 31, 2023, including facilities retiring or repowering by December 31, 2028. As suggested by the commenter, for the final rule, as it had done for the proposal, EPA updated its analysis of the baseline to include all operating plants and incorporate updated information about their operating characteristics (e.g., wastewater treatment in place). The Agency also incorporated more recent information about facility retirements and fuel conversions into the final rule analysis. See the *Supplemental TDD* and EPA's response in Code 7 for details.

EPA disagrees with the commenter that benefit-cost analysis should be performed for each individual component of the regulatory options. The Agency does develop costs and loads for individual technologies and provides this information in the *Supplemental TDD* and in the rule docket. While EPA fully considered each technology for each wastestream, given the number of wastestreams and technology options under consideration, EPA chose to focus additional analysis (e.g., benefits) on four regulatory options. This approach facilitated EPA's ability to determine that the final rule met the statutory requirements of technological availability, economic achievability, and acceptable non-water quality environmental impacts (see Section VII of the preamble and comment Code 1 for further discussion). EPA's decision to bundle technology options to focus the Agency's further analysis is consistent with EPA's approach in developing regulatory options for other point source categories regulated under the Clean Water Act.

Regarding the comment requesting additional information on EPA's analysis of willingness-to-pay for improvements in water quality, EPA provides this information in Chapter 6 and Appendix G of the BCA. Similar details were provided at proposal in Chapter 6 and Appendix H of the 2019 BCA. The commenter specifically questioned why total willingness-to-pay benefits were estimated to be positive when the median water quality change was estimated to be negative for the analysis of the proposed rule.. As discussed in detail in the BCA, total willingness-to-pay benefits reflect both the magnitude and direction (positive or negative) of water quality changes in individual reaches, as well as the geographical distribution of these changes relative to populations with variable levels of willingness-to-pay for those changes. Given positive and negative water quality changes in different reaches (and for different time periods within the analysis), it is possible for the sign of the total willingness-to-pay estimate to differ from that of the median water quality change. For the final rule analysis, total willingness-to-pay and the median water quality change have the same sign.

For additional responses to comments on bromide-related benefits, see response in the section "Bromide/DBP" within this Code. For additional responses to comments on benefits from changes in air emissions, including CO_2-related benefits based on the social cost of carbon and human health benefits from changes in SO_2 and NO_X emissions, see the section "Air Quality-Related Benefits" within this Code.

Unquantified Benefits

Commenters raised concerns about specific unquantified benefits, including the cost of the proposed rule on ecosystems and health impacts and damages associated with carbon emissions and particulate matter precursors like nitrogen oxides and sulfur dioxide.

EPA disagrees that it did not quantify benefits (forgone or realized) from changes in ecosystem services (i.e., recreational use support or nonuse values) resulting from increases or decreases in steam electric power plant discharges. Although these services are not valued separately, they are implicitly included in the total value of benefits from water quality changes under the final rule. As noted in Appendix G of BCA, the meta-regression function EPA used to analyze these benefits, which the Agency updated for the 2020 final rule, is based on meta-data drawn from primary stated preference studies conducted in the United States that estimate willingness-to pay for changes in water quality that provide a variety of ecosystem services including wildlife support, recreational uses (such as fishing, boating, and swimming), and nonuse values. In fact, the meta-regression function used in estimating benefits of water quality changes under the final rule includes explanatory variables that explicitly account for a range of ecosystem services, including recreation, wildlife support, and nonuse. In developing the benefit transfer based on meta-regression, EPA assigned values to independent variables to account for relevant ecosystem services provided by water resources affected by steam electric discharges (e.g., fishing, boating, and swimming). See Appendix G in the final rule BCA for details.

EPA agrees that assessing and monetizing impacts from anticipated changes in air emissions provides a more comprehensive understanding of the benefits of the final rule. For the final rule, EPA estimated both the climate-related benefits of projected changes in CO_2 emissions, as well as the net human health benefits resulting from projected changes in emissions of NO_X, SO_2, and directly emitted particulate matter ($PM_{2.5}$) and projected changes in $PM_{2.5}$ and ozone levels. See Chapter 8 of BCA for details. See response in the section on Air Quality-Related Benefits within this Code for additional EPA responses to comments on its analysis of benefits from changes in CO_2 emissions.

EPA agrees with the commenter that the best practices for cost-benefit analysis incorporate or consider all categories of costs and benefits that could be quantified or monetized. EPA's analysis conforms with these best practices. The Agency considers both quantified and non-quantified benefit categories in weighing benefits and costs of regulatory options as well as uncertainty inherent in benefit-cost estimates. While both benefits and costs values are subject to uncertainties, which EPA discusses in the BCA and RIA, they are based on the best information available to EPA. EPA has also considered any specific suggestions for reducing uncertainty provided by commenters. As such, EPA's analysis is appropriate for presenting loadings and estimating benefits.

As the preamble discussion makes clear, EPA's decisions on the final rule are based on the factors specified by Sections 301 and 304 of the Clean Water Act – most importantly, the technologies selected in the final rule are "available" and the final rule is "economically achievable" for the industry as a whole. EPA notes that the analysis of benefits fulfills the Agency's requirements under Executive Order 12866, but is not a statutory factor for determining effluent limitations and standards.

Water Quality Modeling

EPA disagrees with the comments, and conducted an analysis for the final rule that is reasonable and appropriate for quantifying incremental changes in downstream bromide concentrations. While the input data are subject to uncertainty and conditions may vary across locations and over time, EPA used the best information available to EPA and was transparent about the uncertainties and limitations, including by providing comparisons between modeled and measured concentrations. EPA notes that the commenter did not provide data or sources of data beyond the information available to EPA for this analysis. As stated in Chapter 4 of the BCA, EPA estimates bromide concentrations based on annual average bromide loadings from steam electric power plants over the period of the analysis. The Enhanced Runoff Method (EROM) data included in the National Hydrography Dataset (NHD) Plus v2 attributes provide annual average flow estimates at the medium-resolution NHD reach level and serves as the basis for estimating bromide concentrations from annual average plant-level discharges. Given the long-term conditions represented in EPA's model, the use of EROM flow data and generalized assumptions regarding physical watershed characteristics are reasonable for estimating long-term bromide concentrations in individual reaches nationwide.

Regarding EPA's use of detection limits as surrogate for nondetect measurements in the comparison of modeled and observed bromide concentrations, EPA followed the approach used by Duke Energy, which was the source of most mean observed concentrations used in the analysis (for the Broad, Dan, and Catawba Rivers). Applying the same approach to data for the Lower Allegheny and Ohio River and Tributaries ensures consistency in how nondetect measurements are handled across the datasets.

Drinking Water Benefits – Bromide/DBP

EPA received numerous comments about uncertainty in the understanding of the impacts of bromide on the formation of disinfection byproducts (DBPs), changes in risk to populations served by PWS, and the relationship between exposure to trihalomethanes and bladder cancer. EPA received public comments that further evaluation of certain DBPs should be completed and that the analysis at proposal should be subject to peer review.

For the 2019 proposed rule, EPA quantitatively estimated the effect of changes in surface water bromide levels on drinking water total trihalomethane (TTHM) levels and bladder cancer incidence in exposed populations. EPA also monetized associated changes in human mortality and morbidity. EPA did not update this analysis for the final rule beyond updating the downstream surface water concentrations of bromide and iodine (see Chapter 4 of the BCA.

EPA agrees with the commenter who stated that there will be transitional effects from delaying health and environmental benefits associated with technology installation until the end of 2028, though they will be small. The final rule analysis reflects the effects of these delays by using annual average of loadings projected during two distinct periods (2021-2028, when steam electric power plants would transition from current treatment practices to practices that achieve the revised limits, and 2029-2047, when all plants are projected to employ treatment practices that achieve the revised limits) within the overall analysis period of 2021 through 2047 (see Section 3.2 of the BCA).

EPA acknowledges that the magnitude of halogen loading reductions under the final rule will depend on how many plants enroll in the VIP and that enrollment is subject to some uncertainty. The Agency, however, disagrees that the estimated number of facilities voluntarily opting into the program by the end of 2028 is overstated. See EPA's response to comments in the section on "Benefits Analysis Scope and General Assumptions" under this Code.

A commenter expressed concern that EPA's proposal analysis overestimated the amount of bromide reaching downstream drinking water treatment facilities. For the final rule, EPA revised the estimates of bromide loadings. See EPA's responses in Code 13. In response to comments that the analysis does not account for coal-fired power plant retirements, EPA incorporated the most recent information available about facility retirements and fuel conversions into the final rule analysis. See the *Supplemental TDD* and EPA's response in Code 7 for details.[88]

EPA agrees with the commenter who stated that the membrane technology is likely to provide additional public health benefits in addition to controlling bromide discharges. EPA, however, disagrees that the Agency should set BAT based on membrane filtration. See Section VII of the preamble and EPA's responses to comments regarding the BAT determination and Code 36 for responses related to bromide.

EPA acknowledges and discusses qualitatively in Chapter 2 of the BCA the potential for increased DBP treatment costs at PWS affected by steam electric power plant discharges due to increased bromide loads. EPA notes that although some PWSs may experience increases in bromide concentrations under the final rule compared to baseline, the estimated incremental increases are small (see Chapter 4 of BCA for details). Further, predicting the frequency and magnitude of MCL violations is challenging due to theirLimited availability of data on treatment technologies in place and required treatment technology upgrades prevents reliable estimates of the potential increase in treatment costs (see Section 2.3.2.1 of the BCA). EPA notes that the

[88] Also see *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule* (DCN SE08688). Note that the analysis does not capture additional changes announced since this document was developed.

commenter's statement that avoided costs to utilities may exceed the health benefits of reducing brominated disinfection byproducts was not supported by data or analysis submitted by the commenter.

Drinking Water Benefits - Other Drinking Water Pollutants

EPA agrees with the commenter that for some pollutants that have an MCL above the MCLG (i.e., thallium) or pollutants for which the MCLG is zero (i.e., some trihalomethanes, lead, and arsenic), there may be incremental benefits from reducing concentrations below the MCL. In response to comments, EPA assessed changes in arsenic, lead, and thallium concentrations in source water reaches that may be affected by steam electric power plant discharges. While EPA estimates that the final rule will increase concentrations of these pollutants compared to baseline, the changes are very small, and modeled concentrations under the final rule are below typical detection limits for these contaminants in all reaches, except for one reach that exceeds detection limits for thallium. Given these small changes, EPA reasonably concludes that the change in risk from drinking water use would be very small. See Section 4.2 of the BCA for details.

As noted in the comment, there is no MCL for manganese. However, there is a human health-based NRWQC (0.05-mg/L for consumption of water and organisms) for manganese. This NRWQC corresponds to a 0.05-mg/L federal secondary standard for manganese in drinking water. EPA compared manganese concentrations in source water reaches affected by steam electric power plants to this NRWQC and found that none of the drinking water source reaches exceeded it (see DCN SE09370 for the data files for this analysis). EPA also notes that manganese is a required nutrient (e.g., adequate intake levels for manganese range from 1.2 mg/day for 1- to 3-year-old infants) (Agency for Toxic Substances and Disease Registry, 2012). Adverse neurological effects from exposure to manganese typically occur in children exposed to high level of manganese in drinking water and diet for at least several years (Agency for Toxic Substances and Disease Registry, 2012). Given the magnitude of changes in manganese concentrations in the source water reaches affected by steam electric power plant discharges, it is reasonable to conclude that the potential for measurable effects in children from changes in exposure to manganese in drinking water under the final rule is very small.

Human Health Benefits

EPA agrees with the commenter that the best practices for cost-benefit analysis incorporate or consider all categories of costs and benefits that could be quantified or monetized. EPA's analysis conforms with these best practices. The Agency presents both quantified and non-quantified benefit categories in assessing benefits, as well as costs, of regulatory options as well as uncertainty inherent in these estimates. While both benefit and cost values are subject to uncertainties, which EPA discusses in the BCA and RIA, they are based on the best information available to EPA. EPA has also considered any specific suggestions for reducing uncertainty provided by commenters. As such, EPA's analysis is appropriate for presenting loadings and estimating benefits.

Regarding the benefits analysis specifically, EPA notes that the analysis of benefits fulfills the Agency's requirements under Executive Order 12866, but is not a statutory factor for determining effluent limitations and standards (see response to comments in Code 1). EPA used the best methods and available data to identify, quantify, and wherever possible monetize, the benefits of the rule. Chapter 2 of the BCA discusses several benefit categories that EPA could analyze qualitatively only, or could quantify but not monetize, such as reductions in toxic pollutant concentrations. In response to comments, EPA expanded its qualitative discussion of health effects that were not quantified or monetized in the final rule analysis.

EPA agrees with commenters that steam electric power plant pollutants, such as aluminum, boron, cadmium, hexavalent chromium, manganese, selenium, thallium, and zinc can also affect human health, and lead, mercury, and arsenic can have additional impacts beyond those the Agency quantified in its analysis. Analyses of these health effects require data and information on the relationships between ingestion rate and potential adverse health effects and on the economic value of potential adverse health effects. Thus, due to data limitations and uncertainty in these quantitative relationships, for the final rule EPA did not quantify, nor was it able to monetize, changes in health effects associated with exposure to these pollutants. Despite numerous studies conducted by EPA and other researchers, dose-response functions are available for only a subset of health endpoints associated with steam electric wastewater pollutants. In addition, the available research does not always allow complete economic evaluation, even for quantifiable health effects. Because analyses of these health effects are not possible due to data limitations and uncertainty in the quantitative relationship between ingestion rate and potential adverse health effects or between potential adverse health effects and their economic value, EPA analyzed the health benefits qualitatively following EPA guidelines and OMB Circular A-4.

EPA complemented its qualitative analysis with an assessment of the change in risk of cancer and non-cancer toxic effects from consumption of contaminated fish tissue by estimating the expected changes in the number of receiving and downstream reaches with pollutant concentrations in excess of human health-based NRWQC (see Section 5.7 of BCA for detail). In addition, EPA calculated annual-average daily doses of pollutants for recreational and subsistence fishers and compared the estimated exposure to the relevant oral reference dose (RfD) and lifetime excess cancer risk (LECR) benchmark values. Section 4 of the *Supplemental EA* presents results of this analysis.

The section "Human Health Benefits" within this Code provides EPA's response to comments on the analysis of health impacts associated with exposure to steam electric pollutants that have an MCL above the MCLG (i.e., thallium) or pollutants for which the MCLG is zero (e.g., lead and arsenic). Section 4.2 of the BCA describes EPA's analysis of pollutant concentrations in drinking water treatment plant source waters downstream from steam electric power plant discharges. Relative to baseline concentrations, the changes in arsenic, lead, and thallium concentrations are very small.

EPA agrees in part with the commenter that contaminant co-occurrence may impact risk, though the Agency disagrees that co-occurrence will always increase risk. The Agency discusses the potential for cumulative effects of various pollutants qualitatively (see Chapters 2 and 5 of the BCA for details). Although there are some examples of cumulative cancer risk assessment from exposure to the hazardous air pollutants, most information available on impacts associated with exposure to contaminants in other media examines one contaminant at a time (Evans et al., 2020). There is general consensus in the literature that more research is needed to understand the effects of co-occurring toxic pollutants (Agency for Toxic Substances and Disease Registry, 2009a; Agency for Toxic Substances and Disease Registry, 2009b). With respect to cancer risks, EPA notes that even if cancer risk from co-occurring carcinogens can be considered to be additive, quantifying and monetizing benefits from cumulative risk may not be feasible due to the different health endpoints affected by each carcinogen (e.g., exposure to arsenic is associated with skin cancer, whereas exposure to other toxics found in steam electric power plant discharges is linked to internal organ cancers). With respect to non-cancer risks, quantifying a combined effect of non-carcinogenic chemicals can be even more challenging. For example, although several pollutants found in steam electric power plant discharges are linked to neurotoxicity and IQ losses, dose-response functions for these pollutants are based on different biomarkers. The estimated IQ losses in children ages 0 to 7 are based on blood lead level while IQ losses in infants associated with maternal exposure to mercury are estimated based on mercury hair concentration in pregnant women. Therefore, EPA quantifies and monetizes changes in adverse health effects from exposure to each pollutant separately and treats these estimates (e.g., IQ losses) as additive (see Chapter 5 of BCA for details). The Agency notes that the potential hazard to public health of the joint toxic action of multiple pollutants is typically assessed using endpoint-specific hazard indexes (Agency for Toxic Substances and Disease Registry, 2009a; Agency for Toxic Substances and Disease Registry, 2009b). This approach does not allow for quantification or monetization of benefits.

EPA estimated small forgone health benefits to children under the final rule, compared to baseline. This analysis used the best information available to EPA regarding the relationship between lead and mercury exposure and health outcomes. EPA acknowledges that, if measurable effects are occurring at baseline exposure levels, the quantified value of mercury and lead impacts on children are underestimated due to omission of the effect of exposure to mercury after birth and other impacts on children from exposure to lead, including low birthweight and neonatal mortality from in-utero exposure to lead, decreased postnatal growth in children ages one to 16, delayed puberty, immunological effects, decreased hearing and motor function, or other effects of children's exposure to lead after age seven. The Agency addresses the limitations of its monetized benefits analysis in Section 5.8 of the BCA and discusses these effects qualitatively in Chapter 2 of the BCA. As noted in Chapter 5 of the BCA, EPA estimated that the final rule would have small human health effects, compared to baseline.

The recent European study cited by the commenter (Bellanger et al., 2013) estimated that a change in the maternal hair-mercury by 1 μg/g is associated with an average loss of 0.465 IQ points in infants. To estimate benefits of reducing exposure to mercury, the authors applied this slope factor to a population of pregnant women whose average hair-mercury concentration exceeded 0.58 μg/g. Using this slope factor in the context of the final rule analysis would not be appropriate for two reasons. First, EPA applies the slope factor developed by (Axelrad et al., 2007) to all women exposed to mercury from consumption of recreationally-caught fish as opposed to the subset of women whose hair-mercury concentration is above the threshold used in the study (Bellanger et al., 2013). Second, there is a lack of data on the distribution of hair-mercury concentration in the exposed population for the final rule. Thus, EPA did not implement the approach suggested by the commenter.

Air-Quality Related Benefits – Social Cost of Carbon

EPA disagrees with the commenters' assertion that EPA neglected certain elements of damage in the SC-CO_2 and disagrees that the proposed rule is therefore arbitrary and capricious. Unlike the rules in some of the cases cited by commenters, and as explained in the response in Code 1, EPA did not base its decisions in this final ELG rule on its benefits analysis or on a weighing of costs against benefits. The analysis of benefits fulfills the Agency's requirements under Executive Order 12866, but is not a statutory factor for determining effluent limitations and standards. As the preamble discussion makes clear, EPA's decisions on the final rule are based on the factors specified by Sections 301 and 304, of the Clean Water Act – most importantly, the technologies selected in the final rule are "available" and the final rule is "economically achievable" for the industry as a whole. The analysis of benefits fulfills the Agency's requirements under Executive Order 12866, but is not a statutory factor for determining effluent limitations and standards.

EPA used the same methodology for the final rule as it had used in analyzing the Affordable Clean Energy (ACE) rule. As such, the responses provided in Chapter 7 of the ACE Response to Comments document[89] regarding the social cost of carbon and SC-CO_2 analysis are relevant here as well, and EPA repeats them below with minor changes to reflect considerations specific to the final rule.

The SC-CO_2 estimates presented in the BCA are interim values developed under EO 13783. The executive order withdrew the technical support documents (TSDs) used in the analysis of the 2015 rule (see U.S. EPA, 2015) for describing the global social cost of greenhouse gas estimates developed under the prior Administration as no longer representative of government policy. EO 13783 directed agencies to ensure that estimates of the social cost of greenhouse gases used in regulatory analyses are consistent with the guidance contained in OMB Circular A-4, "including the consideration of appropriate discount rates" (EO 13783, Section 5(c)).

EPA disagrees with the commenter's assertion that it should not use discount rates of 3 percent and 7 percent for its analysis of SC-CO_2 benefits. Circular A-4 states that regulatory analyses "should provide estimates of net benefits using both 3 percent and 7 percent." The 7 percent rate is intended to represent the average before-tax rate of return to private capital in the U.S. economy. The 3 percent rate is intended to reflect the rate at which society discounts future consumption, which is particularly relevant if a regulation is expected to affect private

[89] https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0355-26741

consumption directly. EPA follows this guidance by presenting estimates based on both 3 and 7 percent discount rates in the main analysis described in Chapter 8 of the BCA.

EPA discusses the limitations and uncertainties associated with the SC-CO_2 analysis in Chapter 8 of the BCA. Appendix I of the BCA details the treatment of uncertainty in the interim domestic SC-CO_2 estimates, including the use of Monte Carlo techniques to generate the estimates and the frequency distribution of estimates from the 5th to 95th percentiles. Circular A-4 suggests "further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefit using discount rates of 3 and 7 percent" (page 36). EPA considered the uncertainty in the assumption of discount rates by calculating the domestic SC-CO_2 based on a 2.5 percent discount rate, in addition to the 3 and 7 percent used in the main analysis. The resulting climate benefits using the 2.5 percent discount rate are presented in Appendix I of the BCA.

EPA also acknowledges that the models used to generate SC-CO_2 estimates do not cover all of the costs associated with climate impacts stemming from CO_2 and other GHG emissions. As stated in Chapter 8 and Appendix I of the BCA, additional research is needed in order to expand the quantification of various sources of uncertainty in estimates of the SC-CO_2. National Academies of Sciences et al. (2017) provides recommendations for improvements to the models used to estimate the SC-CO_2. The National Academies report also provides recommendations pertaining to discounting, emphasizing the need to more explicitly model the uncertainty surrounding discount rates over long time horizons, and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, as well as both near-term updates and longer-term research needs. The National Academies report recommended an update cycle for SC-CO_2 estimates of roughly 5 years. Consistent with that recommendation, more time is required to implement the recommendations in a consistent manner across the United States Government.

Air-Quality Related Benefits - Other Air Pollutants

EPA agrees that assessing and monetizing impacts from anticipated changes in air emissions provides a more comprehensive understanding of the benefits of the final rule. EPA had expressed at proposal its intent to quantify and monetize impacts from changes in air emissions of a broader set of air pollutants, and has revised its analysis for the final rule accordingly. Chapter 8 of the BCA describes EPA's methodology for modeling changes in concentrations of criteria air pollutants, including NO_X, SO_2, $PM_{2.5}$, and ozone and quantifying and monetizing the relevant health impacts estimated as a result of the final rule, compared to baseline.

For a discussion of the factors EPA used in determining BAT for the final rules, see Section VII of the preamble. EPA notes that the Agency's BAT decisions reflected in the final rule are not based on a benefits analysis, which EPA conducts pursuant to Executive Order.

Threatened and Endangered Species Benefits

The Agency used the best methods and available data to identify, quantify, and wherever possible monetize, the benefits of the rule, including potential benefits to T&E species. EPA notes that the Agency's BAT decisions reflected in the final rule are not based on a benefits analysis, which EPA conducts pursuant to Executive Order.

EPA conducted an analysis to identify potential impacts to T&E species from changes in projected attainment of freshwater NRWQC in waters intersecting T&E species habitat ranges. Note that EPA's analysis is intended to isolate possible effects of the regulatory options and the final rule on aquatic ecosystems and organisms, including T&E species, however, it does not take into account the fact that the NPDES permit for each steam electric power plant, like all NPDES permits, is required to have limits more stringent than the technology-based limits established by an ELG, wherever necessary to meet applicable water quality standards. Because the analysis does not project where a permit will have more stringent limits than those required by the ELG, it may overestimate any negative impacts to aquatic ecosystems and T&E species, including impacts that will not be realized at all because the permits will be written to include limits as stringent as necessary to meet water quality standards as required by the CWA.

In response to comments, EPA made a number of changes to its analysis of the potential effects of the final rule on T&E species. These changes, as well as reasons for retaining some aspects of the 2015 and 2019 methodology, are discussed below according to the seven issues raised in the comments (see Chapter 7 of BCA for more details).

1. As stated in Chapter 7 of the final rule BCA, EPA used the most current data available from the U.S. FWS Environmental Conservation Online System (ECOS) to construct a database for use in identifying which species have habitat ranges that overlap waters receiving steam electric power plant discharges (both immediate receiving waters and downstream). The database includes all animal species currently listed or in consideration for listing under the ESA. Using these data, the Agency identified 197 species potentially within the scope of the analysis. EPA disagrees with the commenter's characterization of EPA's analysis to identify species relative vulnerability to water pollution as "arbitrary and capricious further analyses." The analysis appropriately focuses on the impacts to aquatic habitats from changes in steam electric power plant discharges. Accordingly, the Agency carefully reviewed species life history to identify species living in aquatic habitats for several life history stages and/or species that obtain a majority of their food from aquatic sources to determine the subset of species to be included in subsequent analyses.
2. EPA agrees with the commenter that the analysis should "give the benefit of the doubt to the species." Therefore, EPA included species "presumed to be extinct, including those not collected for a minimum of 30 years" in its anlaysis of the final rule impacts on T&E species. As shown in Table 7-1 of the BCA report, one species potentially affected by steam electric discharges falls in this category.
3. EPA identified eight species endemic to springhead pools, springs, or caves whose habitat range comes within 200 meters of the reaches receiving steam electric discharges

and noted these species in the BCA (see Appendix H of the BCA for details). The primary habitat for species "endemic" to springs does not receive steam electric power plant discharges. Therefore, while EPA identified these species as vulnerable to water pollution, the Agency did not analyze them further due to their life history. EPA aknowledges that while it is possible for other species living in reaches receiving discharges to travel upstream or downstream and impact biota in other reaches, these impacts are difficult to ascertain or quantify.

4. EPA agrees that water quality issues may be important to species recovery even if not listed explicitly in species recovery plans. The final rule analysis considers all aquatic species to be in the "higher" vulnerability categories (with the exception of species endemic to springs, springhead pools, or caves addressed above) irrespective of whether water pollution is the leading or only contributing cause of decline for a particular species (see Appendix H of the BCA for details).
5. As noted above, the final rule analysis considers all aquatic species to be in the "higher" vulnerability categories. This change addresses the commenter's concern about excluding species whose recovery plans list an industry or entity not within scope of the final ELG as a major impediment to recovery.
6. EPA agrees that providing a full list of T&E species whose habitat ranges intersects the reaches affected by steam electric discharges is appropriate to ensure transparency of its analysis. Appendix H of the BCA provides a full list of T&E species within the scope of the analysis. The appendix also notes the classification of the species' vulnerability to water quality changes (i.e., "lower", "moderate", "higher"), whether the species are endemic to headwater springs and caves, and the number of reaches where estimated concentrations exceed the aquatic life criteria under the baseline or the regulatory options. EPA notes that water pollution was listed as a contributing factor for all species considered in the benefit cost analysis of the final ELG. Therefore, the Agency did not exclude T&E species listed due to non-native species introductions from subsequent analyses (see Chapter 7 for details).
7. EPA reiterates that it used 2020 data obtained from the U.S. FWS for the final rule analysis. As noted in Chapter 7 of BCA, EPA obtained the geographical distribution of T&E species in geographic information system (GIS) shapefile format from the U.S. FWS ECOS. The Service provides the most complete national representation of the range of each ESA-listed species (U.S. FWS, 2019). However, the ECOS portal does not provide shapefiles for the habitats of 13 species potentially located downstream of steam electric power plant discharges. Given the uncertainty associated with the species geographic location, EPA did not include them in the analysis of the final rule impacts.

EPA notes that of the 70 T&E species the commenters identified as likely to be in waters receiving discharges from steam electric plants, 56 species are included in the 2020 analysis. For the remaining 14 species, one species, the Atlantic Pigtoe, is not listed under the ESA. While the U.S. FWS proposed listing Atlantic Pigtoe under ESA in October of 2018, the Service had not finalized this action at the time of EPA's analysis. As for the 13 other species on the commenter's list, ECOS does not provide shapefiles of the habitat ranges and instead describes the critical habitats of these specifies as "wherever is found." As discussed in item 7 above, EPA did not include these species in the analysis because of uncertainty regarding their range.

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42 Statistics

No comment excerpts were received on this topic.

43 Numeric Limits

As described in section XII of the preamble, the final rule establishes limitations for flue gas desulfurization (FGD) wastewater and bottom ash transport water. This response expands on the discussion of EPA's limitations methodology in the preamble in order to address concerns raised by public comments categorized as Code 43 (Numeric Limits).

Several commenters misunderstood EPA's process for developing numeric limits. Subsections 1 through 6 below address EPA's limitations methodology specific to the final rule best available technology economically achievable (BAT) limitations. For context, a brief overview[90] of the limitations development process element addressed in the comment and response is provided in each subsection. See Section 8 of the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental TDD) (EPA-821-R-20-001) for details on EPA's methodology for calculating the limitations presented in the preamble and final rule. Subsection 7 addresses long term performance of ultrafiltration. Subsection 8 of this response provides further discussions of the limitations and methodology specific to the Voluntary Incentives Program (VIP) limitations. Subsection 9 addresses comments on bottom ash (BA) purge limitations.

1. Selection of Pollutants

Some commenters asserted that there should not be a BAT limitation for nitrate-nitrite as N, and they provided several reasons. First commenters assert there is no need for a nitrate-nitrite limitation because the pollutant was frequently non-detect in effluent of the BAT model treatment system (CP+LRTR). Therefore, setting a selenium limitation was sufficient. EPA disagrees that setting a selenium limitation can serve as a proxy for removal of nitrate-nitrite in this instance. EPA acknowledges that microbes in an anoxic/anaerobic biological treatment system preferentially remove nitrate-nitrite before reducing selenium. Although commenters are correct that nitrate-nitrite is removed in the BAT model treatment system, plants are not required to use this exact system when complying with the rule. Based on pilot data, EPA concludes that non-biological technologies (e.g., zero valent iron) could be used instead to achieve the selenium limitations without also removing nitrate-nitrite. As another example, granulated activated carbon (GAC) removes selenium, but has no effect on nitrates. Therefore, EPA finds that limits for both selenium and nitrate/nitrite are necessary.

[90] The overview of the limitations development process is, by necessity, an incomplete summary. As such this overview should not be used to replace the fuller description provided in the Supplemental TDD and in the final rule preamble.

Some commenters also assert that EPA should consider different limitations for FGD wastewater discharges because LRTR is a new emerging control technology and there are only pilot studies to test the technology performance. **EPA disagrees with the commenter's characterization that LRTR is an emerging new control technology. As described in the "**Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule" memorandum (DCN SE08688) as well as the "Flue Gas Desulfurization Wastewater Treatment in Place at Steam Electric Power Plants" memorandum (DCN SE08629), t**here are four full-scale CP+LRTR treatment systems in operation.**

2. Data Selection

The next step in limits development is selection of data on which to base the limits. Four criteria are applied in reviewing available data for use in developing effluent limits; see Supplemental TDD Section 8.2.1.

Section 2 of the Supplemental TDD, section VI of the proposed rule preamble, and section VI of the final rule preamble describe EPA's data collection efforts that informed the proposed rule and the final rule. EPA applied the data selection criteria specified in Supplemental TDD section 8.2.1 to the data it collected through these efforts and identified six data sets reflecting five plants operating the CP+LRTR model technology. EPA used all six of these data sets as the basis for its calculation of BAT effluent limitations for the final rule. These six data sets reflect operation of CP+LRTR pilot plants by three different vendors (further details not provided here due to Confidential Business Information claims).

Several commenters expressed concern that the BAT limitations for FGD wastewater were developed using only pilot study data from CP+LRTR systems. For a discussion of case law that supports EPA's use of pilot data to establish effluent limits, see Response Code 1. The data selection criteria described above and used by EPA for this rulemaking do not differentiate between pilot-scale or full-scale systems; they only require that the data set is derived from a system using the BAT model technology in treating FGD wastewater under normal operating conditions. Use of these criteria ensure the data are valid and sufficiently sensitive for use in these calculations.

Commenters expressed concern that the pilot studies used to develop BAT limitations do not represent all FGD wastewater based on coal type, including lignite coal. These commenters did not provide data for FGD wastewater from lignite coal combustion and commenters did not explain how wastewater generated from other coal types differs from the data used in EPA's analysis. Wet FGD systems are most likely to be used at plants burning bituminous coal because bituminous coal has high sulfur levels. Even so, for the final rule, EPA has included data from a plant that burns both bituminous and sub-bituminous coal. EPA is aware of only one plant that burns lignite coal and discharges FGD wastewater, and EPA does not have monitoring data for this plant. For the pollutants regulated by the final rule (which remain the same in this rule as they were in 2015), EPA concludes FGD wastewater from plants burning lignite is not substantially different from FGD wastewater from plants burning bituminous coal. See response to Comment Code 11 (FGD Wastewater - General) for a further discussion of coal type and its relationship with biological treatment of FGD wastewater.

EPA disagrees with multiple commenters' assertions that flow variations due to fuel blending will inhibit a plant from meeting the BAT limitations. Although different coal types may produce different FGD purge flow rates, EPA does not agree that effluent limitations based on CP followed by biological treatment can interfere with plants switching from one type of coal to another. EPA addressed fuel blending, or fuel flexing, in EPA's response to public comments from the 2015 rule (see DCN EPA-HQ-OW-2009-0819-6469); see response to DCN EPA-HQ-OW-2009-0819-4655, Excerpt Number 107 in Comment Code 10.a – FGD Bio – Demonstration/Performance. The variability of the wastewater and the impact to the treatment efficacy can be mitigated with pretreatment of the wastewater prior to the biological treatment stage. CP systems have demonstrated the ability to manage the FGD wastewater variability at the pretreatment stage prior to biological treatment. Commenters have not provided data to support claims that burning different coals, coal blends, or the timing of these changes in fuels result in concentrations of pollutants or flow rates that result in a wastewater that cannot be treated by the CP+LRTR system.

Some commenters asserted that the data selection criteria should be altered when evaluating data from pilot studies. Examples provided by commenters include data collected during start-up and prior to steady state, inadvertent feed cutoff, and other abnormalities. EPA disagrees it should have altered the data selection criteria because the data are from a pilot. EPA also disagrees with commenter's characterization that EPA is relying upon "tightly controlled, small-scale systems." Pilot studies typically are small-scale but may also be large-scale plant studies such as several of the pilot studies run by Frontier. See Supplemental TDD Section 4 for more information. EPA is not aware of an independent basis for adjusting data sets to account for the use of pilot rather than non-pilot data. All systems, pilot or otherwise, typically have a period of startup and optimization as the system approaches a steady state of operation. Data measured prior to achieving steady state in any treatment system using new wastewater treatment equipment can exhibit high variability that is not representative of typical operation. The period prior to steady state operation represents a period where system optimization is occurring, to include regulating chemical dosages, acclimatizing biological media, and other activities that only occur as treatment is commencing operation. For data used in this rulemaking, EPA carefully considered whether data should be excluded that were obtained prior to steady state operation or during treatment system upset and concluded it was appropriate to exclude such data. EPA also carefully considered data reflecting abnormal operations once the system had reached steady state operation and, provided the abnormalities did not result in a system upset or failure, concluded that such data should not be excluded from the data sets EPA used to calculate the limits. If anything, use of pilot-scale data results in including more system variation or data representative of potential upsets than data from established full-scale systems. This variability is then reflected in the limits calculated using EPA's statistical approach (See Supplemental TDD Section 8 for more information on the statistical approach).

Other commenters asserted that due to the smaller flow volumes of pilots, the system usually can respond to operator adjustments far more quickly than commercial-size systems. Commenters also asserted that where pilot systems are very small the system is more susceptible to changes in flow, pollutant concentrations, and other operating variables. EPA agrees that a smaller biological treatment system in particular is more sensitive to small perturbations in the overall system. With the relatively small volume of a small pilot study (as compared with large-scale pilots), any small change in the system can be amplified. In large-scale operations, these situations may be leveled out by slower mass transfer and mixing limitations inherent to larger treatment systems, or through use of equalization tanks to normalize flows. In other words, general biological treatment engineering principles suggest that an abnormality that could cause a small system to fail could likely be handled or possibly ignored by a much larger system. For pilot studies performed using the Frontier SeHAWK pilot system, susceptibility to small changes in operational variables is especially apparent because the pilot systems, while large-scale, were sized with a lower hydraulic residence time in the biological media than the commercial treatment systems that have been installed in the steam electric power generating industry and elsewhere. Thus, contrary to the comments that only small-scale pilot data was used to set limits, both small-scale and large-scale systems are reflected in the data on which the limit calculations are based.

EPA further disagrees with commenters who suggested that full-scale treatment systems are distinctly different from pilot-scale systems where operators and staff are readily available and can make real-time adjustments in a pilot study that can't be done at full-scale plants. EPA disagrees. General biological treatment engineering principles suggest that operator adjustments and the speed with which those adjustments are made reflect the knowledge and experience of the operator. **Once a full-scale biological treatment system is operating at steady state,** the plant must be well-maintained to maximize uptime. Unlike pilot-scale operations, preventive and predictive maintenance is paramount. **Plant operators and experienced staff knowledgeable with how variables affect treatment efficacy will control those variables more consistently than when operating for a short study time frame in a pilot[91] . For example, plant operators at municipal treatment plants tightly manage their biological treatment systems despite fluctuations in temperature, flow, weather, and pollutant concentrations. EPA outlined response strategies to address issues with FGD wastewater variability in "**Memorandum to the Steam Electric Rulemaking Record: Variability in FGD Wastewater: Monitoring and Response" (DCN SE05846).

Several commenters asserted that two pilot studies, 2027 and 2066, had low concentrations of mercury and selenium in untreated FGD wastewater and use of data from those studies would result in lower mercury and selenium limits than would occur at most plants. The commenters are incorrect that the record contains untreated FGD wastewater analytical data for these pilots. The "pilot influent" for pilot 2027, as referenced by commenters, is not untreated FGD wastewater. The influent to pilot 2027 was FGD wastewater that had been initially treated

[91] American Institute of Chemical Engineers. May 2016. "Understand Pilot-Plant Design Specifications" (DCN SE09223).

through a CP treatment system. The CP system removes significant levels of mercury and some selenium from the FGD wastewater, so the lower "pilot influent" concentrations for pilot 2027 would be expected at that point in the treatment system. (Note, however, EPA excluded all mercury data for pilot 2027 due to the analytical method used.) For pilot 2066, the influent to the pilot system is FGD wastewater that has been initially treated through a gypsum pond followed by a clear water pond. It is unclear from the data and information on the pilot study obtained via the 2010 *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Questionnaire) (EPA-HQ-OW-2009-0819-8115) what the residence time is of these two impoundments, and whether there are any other wastewater sources diluting the FGD wastewater. In any case, some portion of selenium and mercury in FGD wastewater are in the particulate phase, so it is to be expected that after settling in an impoundment, the "pretreatment influent" would have both a lower mercury and selenium concentration than would be the case in untreated FGD wastewater.

Table 1 shows mercury and selenium concentrations from the Pilot 2066 and from EPA's 2015 analytical database, allowing comparison of those data with the 7 plants provided by EPRI (EPA-HQ-OW-2009-0819-8293). As shown in Table 1, data from the Steam Electric Questionnaire Database for pilot 2066 demonstrates that mercury and selenium concentrations in untreated FGD wastewater are similar to the EPRI-provided data from comments and EPA's 2015 analytical database (EPA-HQ-OW-2009-0819-5640). The plant 2066 mercury concentration median, minimum, and maximum all fall within the range of all other data used in the proposed rule. EPA further notes that the mercury values from plant 2066 are not the lowest mercury effluent levels of all plants. Table 2 shows mercury and selenium concentrations in surface impoundment effluent from Pilot 2066 and EPA's 2015 analytical database, allowing comparison of those data with the data provided by EPRI (EPA-HQ-OW-2009-0819-1757). Also provided in Table 2 are the average FGD loading concentrations used by EPA. As shown in Table 2, surface impoundment effluent data for pilot 2066 is similar to those data from a previous EPRI report discussing impoundment effluent and EPA's 2015 analytical database. Also shown in Table 2 are the average FGD concentration data used to calculate FGD loadings from a surface impoundment. EPA views pilots 2027 and 2066 as representative of FGD wastewater, and as such, EPA used both pilots in the data set used to develop CP+LRTR limitations, except as noted above for the mercury data from the pilot at plant 2027 which was excluded for other reasons.

Table 1. Comparison of Untreated FGD Wastewater Concentrations

Pollutant	2010 Data from Steam Electric Questionnaire Database for Pilot 2066	EPRI Comment Letter: Excerpt 23 (EPA-HQ-OW-2009-0819-8293)							EPA 2015 Analytical Database [a]
		Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7	
Mercury (ng/L)	Average: 182,000 Minimum: 70.8	104,000	267,000	1,100,000	188,000	199,000	246,000	288,000	Average: 440,000 Minimum: 100 Maximum: 4,200,000

Table 1. Comparison of Untreated FGD Wastewater Concentrations

Pollutant	2010 Data from Steam Electric Questionnaire Database for Pilot 2066	EPRI Comment Letter: Excerpt 23 (EPA-HQ-OW-2009-0819-8293)							EPA 2015 Analytical Database [a]
		Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7	
	Maximum: 522,000								
Selenium (ug/L)	Average: 5,890 Minimum: 270 Maximum: 16,600	1,570	3,170	16,100	881	3,190	3,960	3,960	Average: 3,695 Minimum: 105 Maximum: 26,200

a – Data based on 12 plants, 832 mercury observations and 501 selenium observations (EPA-HQ-OW-2009-0819-5640).

Table 2. Comparison of Surface Impoundment Effluent Concentrations for FGD Wastewater

Pollutant	LRTR Pilot Study for Pilot 2066	EPRI Report 1010162 (EPA-HQ-OW-2009-0819-1757)		EPA 2015 Analytical Database [a]	FGD Loadings Concentrations [b] (Supplemental TDD Section 6)
		Site U	Site Y		
Mercury (ng/L)	Average: 5,310 Minimum: 157 Maximum: 23,200	7,500	9,500	Average: 1,500 Minimum: 110 Maximum: 7,320	Average: 7,780 Minimum: 62.7 Maximum: 91,500
Selenium (ug/L)	Average: 64 Minimum: 7.2 Maximum: 135	40	172	Average: 1,770 Minimum: 991 Maximum: 2,740	Average: 1,170 Minimum: 77.9 Maximum: 4,770

a – Data based on one plant with 52 observations (EPA-HQ-OW-2009-0819-5640).
b – Data based on eight plants, 135 observations for mercury and 220 observations for selenium (EPA-821-R-20-001).

Other commenters asserted that the data EPA used to establish effluent limits does not reflect plants operating on a cycling basis, such as a prolonged shutdown of a low utilization unit. EPA previously examined whether cycling operations at facilities affect the ability of a CP plus biological treatment system to meet BAT limitations in support of the 2015 rule. See the "Memorandum to the Steam Electric Rulemaking Record: Variability in FGD Wastewater: Monitoring and Response" (DCN SE05846). Both baseload and cycling power generation operations are included in the data to calculate BAT limitations. Overall, the record indicates that cycling operations and shutdown periods, whether short or long in duration, do not result in significant fluctuations such that plants are unable to meet the final rule effluent limitations. Commenters did not provide new data or explain how cycling can impact the wastewater characterization such that a CP+LRTR treatment system becomes less effective or is unable to achieve the same effluent quality as it otherwise would.

Several commenters conveyed that EPA Method 200.8 is inappropriate for mercury analysis for several reasons, including that it "is not an EPA approved analytical method found in 40 CFR

Part 136 for quantifying low levels of mercury," and that there is "potential for low biases due to mercury volatilization in the sample digestion step." EPA agrees with commenters that EPA Method 200.8 is inappropriate for mercury analysis in this instance. In follow up with the plant 2027, EPA confirmed that pilot 2027 used an analytical method that is substantially the same as EPA Method 200.8 for all mercury analyses. EPA Method 200.8 does not quantify to the low levels of mercury necessary and appropriate for measuring mercury in FGD wastewater effluent. EPA therefore concluded that the method used by plant 2027 was not appropriate for mercury analysis in the samples the data were drawn from because it could not reliably quantify the low levels of mercury of interest in those samples. EPA therefore excluded all mercury data from pilot 2027. EPA disagrees with commenters who asserted that selenium data from plant 2027 should also be excluded, as the plant used an appropriate analytical method for selenium.

3. Data Exclusions and Substitutions

Once data were selected, EPA excluded or substituted certain data in calculating the limitations. In general, EPA used detected values and, for non-detected values EPA used sample-specific detection limits. See Supplemental TDD section 8.2.2.

Commenters suggested that limitations should allow facilities flexibility to accommodate what one commenter described as a "wide variety of weather, operational characteristics, and other variables." EPA agrees the limitations should reflect such variables and notes that EPA's methodology to establish limits used plant data **representing a range of size (i.e., generating capacity), location (including climate), and plant configuration and operating conditions (including factors such as coal types, coal sources, generation rate cycling/variation, and seasonality). Having a range of operating characteristics allowed the calculated limitations to more broadly represent the industry while still providing achievable limitations for all plants.**

Commenters disagreed with EPA's exclusion of certain data abnormalities from pilot studies noting that pilot studies encounter upsets as the technology vendor and plant operator attempt to optimize the system. Commenters also asserted that only data collected during documented serious failures should be excluded. EPA agrees that pilot studies can encounter upsets as the technology vendor and plant operator attempt to optimize the system, and EPA agrees that data reflecting serious failures should be excluded. However, EPA has included the data from Pilot 2019 identified as "abnormal" by one commenter from dates 13, 20, 21, 69, and 70. EPA is not including days 183-190 as these data reflect operators testing the capabilities of the technology, e.g. spiking pollutants in the influent, changing flow rates beyond standard operating conditions, and other settings that were designed to break the technology. For more information on data excluded as a result of public comment see DCN SE09462.

An upset (i.e., failure) of a treatment system, regardless of whether it is full-scale or smaller pilot-scale, is not analogous to operational variability that occurs at plants during cycling (including startup and shutdown) or due to changes in coal, air pollution control equipment operation, or other operational variables. A failure, or upset, of the treatment system is separately addressed by National Pollutant Discharge Elimination System (NPDES) regulations and in the upset and bypass provisions included in all NPDES permits (see 40 CFR 122.41(m) and (n) for regulations regarding upset and bypass conditions). Because both situations, the startup/optimization period as the system approaches steady state, and failures or upsets of the treatment system, represent conditions outside of normal operation, EPA excluded these data. The final rule explicitly allows permitting authorities to consider the length of system optimization in selecting an "as soon as possible" date under 423.11(t).

4. Data Editing

After excluding and aggregating the data, EPA applied data editing criteria on a pollutant-by-pollutant basis to select the data sets to be used for developing the limitations for each technology option. For explanation of EPA's data editing process, see Supplemental TDD section 8.2.4.

Some commenters asserted that the effluent nitrate/nitrite as N data set was both too small and full of non-detects, and therefore a nitrate/nitrite as N limitation was inappropriate. EPA disagrees. Even though many of the effluent samples did not detect nitrate-nitrite, this fact does not negate the appropriateness of an effluent limit. As is stated in Section 6.6.1 of the 2015 *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2015 TDD) (EPA-821-R-15-007), numeric effluent limitations are established for pollutants that have been quantified at a sufficient frequency at treatable levels. More specifically, the pollutant first must be detected at any concentration in 50 percent of the samples. This was true in the case of nitrate-nitrite. Second, the pollutant must pass the LTA test to ensure that the pollutants are present in the influent at sufficient concentrations to evaluate treatment effectiveness at the plant for the purpose of calculating effluent limitations. This was also true for nitrate-nitrite data with one exception (plant 2097). Nitrate-nitrite was identified as a pollutant of concern (section a. above), nitrate-nitrite was quantified at treatable levels (section b. above), and one or more nitrate-nitrite data sets passed the LTA test; therefore, EPA set BAT limits.

5. Selection of Percentiles

EPA calculates effluent limitations based on percentiles high enough to accommodate reasonably anticipated variability within control of the plant, and low enough to reflect a level of performance consistent with the CWA requirement that these effluent limitations be based on the best available technology economically achievable for existing sources and the best available demonstrated control technology for new sources. The daily maximum limitation in the final rule is an estimate of the 99th percentile of the distribution of the *daily* measurements. The monthly average limitation in the final rule is an estimate of the 95th percentile of the distribution of the *monthly* averages of the daily measurements. See Supplemental TDD section 8.2.5.

EPA's methodology, which is longstanding, has been upheld by the courts reviewing rules using this approach. *See, e.g., Chem. Mfrs. Ass'n v. EPA*, 877 F.2d 177, 229 (5th Cir. 1989); *Nat'l*

Wildlife Federation v. EPA, 286 F.3d 554, 572 (D.C. Cir. 2002) (In upholding EPA's decision to set monthly average limitation at the 95th percentile, the court stated, "EPA has considerable discretion in determining a technical approach that will ensure that effluent limitations reasonably account for the expected variability in plant operations while still maintaining an effective level of control. Industry petitioners ignore the fact that after those rulemakings, EPA determined 'as a matter of policy that the 95th percentile was a more appropriate choice for monthly average limitations in all industrial effluent guidelines rulemakings because the variability of monthly averages is less than the variability of daily measurements.' EPA has followed that policy in developing monthly average limitations in all effluent guidelines rulemakings since 1987. It was neither arbitrary nor capricious for EPA to continue that policy here.") (citing *Weyerhaeuser v. Costle*, 590 F.2d 1011, 1056-58 (D.C. Cir. 1978)).

One commenter asserted that "a number of the selenium and mercury measurements in the EPA data sets used for determining ELG limits are above both the daily and monthly average numeric discharge limits." Therefore, this commenter concluded that plants would not meet the final limitations. EPA disagrees. EPA acknowledges that there are both selenium and mercury measurements in the EPA data sets used for determining ELG limits that are above the BAT limitations. However, the limitations in the final rule are a statistical representation calculated using the measured values in the EPA data set, taking into account the projected pollutant-specific long-term average and variability around that long-term average. The monthly average for both selenium and mercury is calculated as the 95th percentile of the projected distribution of the monthly averages of the historical daily effluent values; the daily maximum limitation is the estimate of the 99th percentile of the projected distribution of daily effluent values. By the nature of the statistical model, there will be measured values in the underlying data sets that are above the BAT limitations. EPA notes that it has used this statistical model for decades (including, for example, in ELGs established for such industries as Organic Chemicals, Plastics, and Synthetic Fibers (1987), Pesticides Chemical Manufacturing (1993), and Pulp, Paper and Paperboard (1998)), and it has been upheld as described above. Some comments reflect an apparent misunderstanding that by establishing effluent limitations based on certain percentiles of the statistical distributions EPA expects occasional exceedances of the limitations. This is incorrect. EPA promulgates limitations that plants are capable of complying with at all times by properly operating and maintaining the model treatment technologies (in this case, CP+LRTR). These limitations are based on statistical modeling of the data and engineering review of the limitations and data. EPA does not expect plants will operate their treatment systems to violate the limitations at some pre-set rate merely because probability models are used to develop limitations. Further, in the many decades implementing this statistical approach, EPA does not have information indicating that limits established using this approach result in industry non-compliance. By using a monthly average combined with a daily maximum, EPA expects facilities will design their treatment systems to meet the long-term average performance presented in Section 8 of the Supplemental TDD, and in doing so will operate their systems such that they will comply with the maximum daily and average monthly effluent limits established in the final rule.

6. Calculation of the limitations

See Supplemental TDD section 8.2.6 for explanation of EPA's methodology establishing the long-term average, daily maximum and 30-day maximum limitations.

Commenters expressed concern that the data set used for setting a nitrate-nitrite limitation is too small, and that the statistical model is not appropriate for use in establishing effluent limitations when there are too few detected results. EPA disagrees. As described in Section 8.2.6 of the Supplemental TDD, the calculation of the plant-specific monthly variability factor assumes that the monthly averages are based on the pollutant being monitored weekly (approximately four times each month). In cases when there were not enough distinct detected values for a specific pollutant at a specific plant, then the statistical model was not used to obtain the variability factors for that plant. In these cases, EPA excluded the data for the pollutant at the plant from the calculation of the treatment technology monthly variability factors. Further, a monthly limit is not established when the daily limit is equal to the long-term average (LTA). EPA's data included well over one hundred nitrate-nitrite samples, including, as described above, samples above the detection limit. Therefore, EPA was able to perform a statistical analysis that would give a reliable estimate of long-term average, monthly average, and daily maximum performance and thus set BAT limits for nitrate-nitrite.

Commenters noted more stringent limitations in the proposal for certain pollutants, as compared to the 2013 proposed rule or 2015 final rule, were inappropriate for the final rule. EPA disagrees. Consistent with the proposed rule limitations, the final rule limitations reflect the performance of the technology basis for the rule. While limitations for some pollutants are going down, as compared to the 2015 rule, limitations for other pollutants are going up. Under EPA's statistical methodology for deriving limits, the effluent limit values are dependent in part on the variability in the data set. For example, it is not unusual for the daily maximum to increase and simultaneously the monthly average to decrease, all other things being equal, just by reducing the variability in the data set (or vice-versa). EPA notes that the long-term averages for each pollutant in both the LRTR and the HRTR systems are approximately the same, but as described above, there is more variability in the LRTR datasets. Therefore, the daily and monthly limits calculated for HRTR and LRTR (notwithstanding variability as just described) are, in effect, also approximately the same. See the response to Code 11 (FGD Wastewater – General) for a more detailed discussion of this issue.

7. Long-Term Performance of the Ultrafiltration Unit Process.

Commenters asserted that there is uncertainty with treatment efficiency and long-term performance, including for ultrafiltration (UF) membrane treatment. EPA disagrees. In EPA's experience studying wastewater, drinking water, and industrial treatment, UF unit processes have shown to be effective. Regarding long term performance, EPA disagrees with the commenters who suggest that uncertainty with the performance of all membrane types means that performance of a UF unit is also uncertain. In the Supplemental TDD and the final rule preamble EPA discusses the challenges with membrane systems to treat FGD wastewater and the discussion is focused on challenges with reverse osmosis and nanofiltration as the primary treatment for FGD. To be clear, the CP+LRTR technology option utilizes UF as a polishing stage and EPA's record demonstrates that the use of this type of membrane for polishing is demonstrated and available, as required by the CWA. See the Supplemental TDD Section 4.1 and Section 8.2 for more information.

One of the pilot studies included in limitations development had a duration of over one year: pilot 2066 for 423 days (DCN SE09460). Ultrafiltration was used as a polishing treatment throughout the duration of pilot test 2066 without any need for replacement. The longitudinal plot of mercury for pilot 2066 demonstrates relatively consistent removal throughout the pilot study. In addition, Frontier has four full-scale LRTR systems in operation in the steam electric power generating industry, with the first installation in early 2019. While data from these plants were not used to establish BAT limitations, Frontier has noted that ultrafiltration membranes used for polishing require replacement every eight to 12 years to continue removing pollutants at optimal levels (DCN SE08587). SUEZ, a vendor of the HRTR technology ABMet, has stated that ultrafiltration membrane replacement is needed every "**eight to 10 years, depending on the characteristics of the wastewater being treated" (**EPA-HQ-OW-2009-0819-8458-A1**, Excerpt Number 6). The commenter did not provide any data indicating that EPA's assumed useful life of ultrafiltration equipment is incorrect or data to demonstrate reduced treatment efficiency over time. The ultrafiltration membrane is intended as a polishing step in the CP+LRTR system; as such, under normal operating conditions, the majority of the pollutant removals are achieved by the CP and biological reactor steps.**

8. FGD - Voluntary Incentives Program (VIP) Limitations

Specific to the VIP limitations, commenters assert chemical precipitation is an appropriate pretreatment prior to the membrane. As discussed in response to Code 17 (FGD Wastewater – Membrane Filtration), vendors of membrane filtration technologies claim that CP is not required as pretreatment, however EPA agrees with commenters that much of the data used to establish effluent limitations does reflect pilot studies where CP pretreatment was employed. As discussed in the preamble, for the final rule, EPA has revised its cost estimates for the VIP to include CP as pretreatment prior to membrane filtration (see "FGD Membrane Filtration with Encapsulation Cost Methodology" memorandum (DCN SE08625)). To ensure that estimated compliance costs and effluent limitations are consistent, EPA also updated its data set used to calculate effluent limitations for the VIP. As described in Section 8 of the Supplemental TDD, only data reflecting CP pretreatment are used in the VIP limits calculation. Any data where CP is not operated as pretreatment have been excluded. While EPA assumes this level of pretreatment for its analyses, to the extent that a facility could meet the VIP limitations with some less effective pretreatment (e.g., microfiltration only), nothing in the final rule would prohibit the use of this alternative.

Commenters stated that the mercury dataset EPA used to set VIP limits is a "poor basis for the setting of national limits" because it is comprised of data from two pilot studies, includes a large number of non-detect values in treated effluent, and there was only one monthly average value available to compare to the computed monthly average limit, which the commenter asserts is inadequate data to set a monthly average limit. EPA disagrees. First, the dataset meets EPA's criteria (see Subsection 2 for more details). Second, a dataset that includes a large number of non-detect values in treated effluent, especially when a highly sensitive analytical method is used, like EPA's mercury data set here, illustrates a highly effective treatment technology that warrants consideration as a basis for BAT limitations. EPA notes that the amount of data used by the Agency was limited because individualized data underlying several pilot studies that EPA obtained were not provided voluntarily by vendors or plant operators. However, it is unnecessary to have large data sets where observations were collected at a sufficient frequency to directly calculate monthly averages. The statistical model used by EPA for calculating limitations is a modified delta-lognormal distribution. Precedent for the valid use of the modified delta lognormal procedure can be found in the ELG rulemakings for industries involving Organic Chemicals, Plastics, and Synthetic Fibers (1987) and Pesticides Chemical Manufacturing (1993). EPA's data set consists of a mixture of detected and non-detected values. The modified delta-lognormal distribution models the data as a mixture of detected measurements that follow a lognormal distribution and non-detect measurements that occur with a certain probability. The model also allows for the possibility that non-detected measurements occur at multiple sample-specific detection limitations.[92] Since the LRTR data fit the modified delta-lognormal model , EPA determined that this model is appropriate for these data and calculated the limitations following the methodology (as explained in Supplemental TDD Section 8).

One commenter argued that "half of the data points excluded by EPA were justified based on pretreatment upsets or pretreatment abnormal operations." The commenter was specifically addressing the data used to calculate the VIP limitations. This statement lacks sufficient clarity about which data points the commenter believes were excluded and whether or why the commenter believes such exclusions were in error. However, the comment mischaracterizes the reason EPA excluded much of the data it excluded. For example, rather than being due to an upset, data for pilot 4060 were excluded because the wastewater did not reflect the treatment of FGD wastewater. Specifically, data for weeks 1 and 2 were excluded because the wastewater was largely comprised of leachate and for weeks 8 and 9 because the wastewater included mostly brine (membrane reject stream). Other data for 4060 were excluded because there were issues related to laboratory analysis. For more information on data excluded see DCN SE09462.

For the proposed rule, EPA conducted an alternative analysis for both LRTR and membrane limitations, to evaluate how limitations may change based on including or excluding specific datapoints. There are certain data that, although included in the derivation of effluent limitations, EPA excluded in an alternative analysis. See the Supplemental Statistical Support Document: Effluent Limitations for Proposed Steam Electric Power Generating Effluent Limitations Guidelines and Standards (DCN SE08055) for a discussion of this alternative analysis, the purpose of it, and what it showed. The proposed rule document included a clerical error regarding which data set was the main versus alternative analysis. For the final rule, EPA

[92] In other situations, there could be too few detected results and this model would not be appropriate for use in establishing the effluent limitations. In such cases, the monthly average limitation would not be calculated and only a daily maximum limitation would be set based on the detection limit.

corrected this clerical error. The proposed limitations and final limitations use the larger data set with fewer exclusions than the alternative analysis; however, EPA had incorrectly termed the larger data set as the "Secondary Analysis" in the proposed rule record.

Comments expressed concern that EPA did not include pilot 4028 data for days 1 to 41. EPA finds this comment to be in error. These data points were included in the calculation of limitations; they were only excluded for the alternative analysis described above. Thus, the handling of this data set is not inconsistent with how EPA handled the pilot 4060 dataset.

A commenter mentioned additional data sets from pilots of New Logic and BKT membrane systems, but which EPA did not use to set limitations based on membrane systems. This commenter argued "these data suggest that plants may need to install additional RO systems to polish the permeate in order to meet the proposed numerical limits and/or sacrifice recovery in order to meet the proposed limits. This step could lead to significantly higher costs." Based on the performance of the membrane dataset, EPA disagrees that additional treatment beyond what was included in the cost estimates for the membrane filtration technology is needed to meet the limitations set under the VIP for permeate discharge (should a plant choose to discharge the permeate instead of recycling it, which EPA estimates is the lower cost option) VIP program.

Commenters point to specific data values higher than the VIP limitations, asserting the conclusion that the plants can't meet the limits. EPA disagrees. See Subsection 5 of this response for further discussion on the statistical model EPA used to calculate the VIP limits for permeate.

9. Bottom Ash - Purge Limitations

As described in section XIII.B of the preamble, EPA finalized the BAT pollutant discharge allowance in the form of a site-specific volumetric purge (not to exceed 10 percent of the system volume) for bottom ash (BA) transport water from high recycle rate (HRR) systems. The plant-specific purge volume and effluent limitations for any wastewater purged from the HRR system are to be determined by the NPDES permitting authority on a case-by-case basis using best professional judgement (BPJ) that reflects the BAT level of control for this wastestream based on the facts at that site. See section VII.B.2 of the preamble for more information.

BA purge water, in the final rule, is defined as a new wastestream and consists of the water permissibly purged from the HRR system. As described in section VII.B.2 of the preamble, because this wastewater is no longer defined as BA transport water, EPA has made conforming changes to the best practicable control technology currently available (BPT) regulations to make clear that the previously established BPT limitations on total suspended solids (TSS) and oil and grease are also applicable to BA purge water.

Some commenters assert that the BAT limitations for BA purge water should not be based on TSS removal or set equal to BPT limitations. See section VII.B.2 of the preamble for EPA's rationale for not selecting surface impoundments as the BAT technology basis and not setting BAT equal to the BPT limitations (except with respect to some limited subcategories where lined surface impoundments were selected as BAT). Other commenters claim that limitations based on TSS removal equal to existing BPT would achieve the same pollutant removal performance as BAT limitations based on CP. EPA disagrees because CP also removes dissolved solids which would not be removed through solids settling in a surface impoundment.

Other commenters stated that using a CP treatment system to treat the BA purge could exceed the costs of zero discharge and could be cost prohibitive. While the term “cost prohibitive” is not defined by commenters, EPA agrees with commenters that, in some cases, using a CP treatment system to treat the BA purge could exceed the costs of zero discharge. The 100 gpm system, costed by one commenter, is comparable in size to the average BA purge water flow. The estimated annualized cost of $2.3 million per year, as cited by this commenter, on top of the costs to install an HRR system due to the Coal Combustion Residuals (CCR) rule or the Effluent Limitations Guidelines and Standards (ELG), would be more expensive than baseline costs, which reflect the 2015 rule requirements of zero discharge vis dry handling/closed-loop systems. EPA disagrees that because CP is more costly that EPA should select surface impoundments as BAT nationwide. EPA maintains that some wet handling systems may have small, consistent purges that can be directed to existing wastewater treatment systems (e.g., those installed to comply with WQBELs) or systems that will be installed as a result of this final rule (e.g., CP+LRTR for FGD wastewater). Under the final rule permitting authorities will determine the appropriate limits for BA purge water after a site-specific BPJ analysis.

EPA disagrees with commenters that the Agency should mandate best management practices (BMP) plans emphasizing maximum recycling of BA purge water in lieu of letting permitting authorities establish BAT limitations on a site-specific basis using BPJ. As discussed in section VII.B.2 of the final rule preamble, EPA selects as BAT a technology that is available nationally and economically achievable by the industry as a whole. Only after establishing those BAT limitations might EPA impose an additional BMP plan. For the final rule, EPA established BAT as HRR but under some subcategories EPA established lined surface impoundments in combination with a BMP plan, not only a BMP plan as commenters are suggesting. For further response to comments on BMP plans see comment code 22.

EPA disagrees in part with commenters that the process of moving from a once-through BA system to a HRR system increases the TSS in wastewater such that plants would require “applying additional technologies/operational measures” to meet the BPT TSS limitations. In multiple meetings with electric utilities, engineers stated that purged BA transport water would be sent to low volume wastewater systems (particularly concrete settling basins) which are already designed to meet BPT TSS limitations (See SE09066, SE08179 and EPA-HQ-OW-2009-0819-8320-A1).

While EPA agrees with commenters that establishing a uniform set of national numeric effluent limitations for BA purge water may be challenging due to variability in plant-specific configurations, climate, and other conditions, EPA disagrees that this makes establishing BAT limitations beyond existing BPT limitations infeasible. As discussed previously and in section VII.B.2 of the preamble, EPA determined that permitting authorities are in a better position to examine the site-specific facts and factors and establish site-specific BAT limitations based on best professional judgement.

EPA disagrees with commenters who asserted that the industry does not have operating experience with HRR systems. EPA's record demonstrates that more than 22 percent of facilities already employ a HRR system for BA transport water.

Responses to comments related to the selection of BAT and availability timing are discussed in comment codes 21a and 33, respectively.

EPA disagrees with commenter's claims that the Agency should maintain the zero discharge limitations for BA transport water from the 2015 rule. See section VII.B.2 of the preamble for EPA's rationale for revising the BAT technology basis from dry or closed-loop BA systems to HRR systems. Unlike the example cited by the commenter, there are insufficient data in the rulemaking record to set a uniform, nationally applicable limitation as zero discharge for BA transport water. Information gathered since the 2015 rule indicates that zero discharge does not reflect BAT, as discussed in the preamble. See the response to Code 23 (BA Transport Water – Zero Discharge) for additional discussion of zero discharge BA systems.

44 Executive Orders

EO 12866 – General Discussion of Social Cost vs Benefits

EPA disagrees with the commenter's assertion that the Agency's benefit cost analysis is fundamentally flawed. The Agency responded to the two specific issues raised by the commenter regarding CO_2-related benefits and VIP separately in Code 41 (see the section "Air-Quality Related Benefits" regarding CO_2-related benefits and section "Benefits Analysis Scope and General Assumptions" regarding VIP).

EPA also disagrees that the term "social costs" is misleading. Social costs, like benefits, can be positive or negative. EPA estimated social costs consistent with Executive Orders 12866, 13563, and 13771, OMB's Circular A-4 and EPA's *Guidelines for Preparing Economic Analyses.* As described in the EPA Guidelines, "social costs represent the total burden a regulation will impose on the economy; it can be defined as the sum of all opportunity costs incurred as a result of the regulation. These opportunity costs consist of the value lost to society of all the goods and services that will not be produced and consumed if firms comply with the regulation and reallocate resources away from production activities and towards pollution abatement. To be complete, an estimate of social cost should include both the opportunity costs of current consumption that will be forgone as a result of the regulation, and the losses that may result if the regulation reduces capital investment and thus future consumption."

As described in Chapter 12 of the Benefit Cost Analysis (BCA), social costs analyzed for the final rule include costs incurred by both private entities and the government and are evaluated on a pre-tax, year-by-year basis. Consistent with the executive orders and EPA's guidelines, EPA also analyzed the benefits of the rule, including "forgone benefits" that represent reductions in social welfare, compared to the baseline. Under the convention EPA used for the analysis, forgone benefits are presented as negative benefit values (cost savings are also presented as negative values). EPA presents both costs and benefits, positive or negative, in the BCA. EPA also disagrees with the commenter's statement that cost is "the motivating factor" for revising the effluent limitations guidelines and standards (ELG) and for establishing the limitations. As required by the CWA, the final rule is based on the statutory factors specified in sections 301(b) and 304(b). EPA applied these factors in selecting the option it is now finalizing. These factors are discussed in more detail in Sections IV and VII of the preamble for the final rule.

In addition, EPA disagrees that the final regulatory action violates the Administrative Procedure Act or Clean Water Act. EPA followed all rulemaking steps outlined in the Administrative Procedure Act (see response to comments in Code 1) as well as other regulatory analytical directives (e.g., cost-benefit analysis, distributional analysis) established by Executive Order 12866 and Office of Management and Budget (OMB) Circular A-4, the Regulatory Flexibility Act (RFA), and the Unfunded Mandates Reform Act (UMRA), and other applicable administrative directives (e.g., , Executive Orders 12898, 13771, 13045, 13132, 13175, 13211; see Chapter 10 of RIA for details).

EPA used the best methods and available data to identify, quantify, and wherever possible monetize, the benefits of the rule. EPA quantified and monetized a range of human health, ecological, and ancillary benefit categories, including human health impacts from changes in air emissions, and qualitatively described benefit categories that cannot be quantified or monetized due to data limitations (see Chapter 2 of BCA for detail). EPA has considered many factors in evaluating the benefits and costs of the final rule, including the degree to which benefits and costs can be monetized fully, the uncertainties associated with benefit and cost calculations and the distribution of the final rule impacts across society. For example, EPA carefully examined whether the change in benefits from the final rule may be differentially distributed among population subgroups (minority and low-income population) in the affected areas (see Chapter 14 of BCA for detail). EPA notes that the analysis of benefits fulfills the Agency's requirements under Executive Order 12866 and is, not a statutory factor for determining effluent limitations and standards. For further discussion of the consideration of benefits in the development of the final ELGs, see response in Code 1 (Legal Authority).

EPA disagrees with the commenters assertion that the benefit analysis for the proposed rule omitted benefit categories. The benefits categories identified by the commenter were, at a minimum, discussed qualitatively, consistent with EPA's *Guidelines for Preparing Economic Analyses* (Guidelines) and OMB's Circular A-4 and as is the practice for benefits for which data or methodologies are insufficient to support quantification and monetization. In response to comments, EPA revised its analysis to quantify and monetize additional benefit categories in the analysis of the final rule. Specifically, the Agency quantified and monetized human health impacts from changes in air emissions resulting from the final rule (see Chapter 8 of the final rule BCA).

EPA disagrees with the commenter that BCA is subject to "structural flaws that obscure the true costs of the rule." EPA also disagrees with the commenter that the Agency's presentation of benefit cost analysis hampers public review and assessment of regulatory alternatives. Both the Regulatory Impact Analysis (RIA) and the BCA clearly document all analyses, analytic assumptions, and limitations and uncertainties inherent in each analytic step. EPA provides supporting data in the docket for the rule.

EPA addresses the three specific issues characterized by the commenter as "major shortcomings" below:

- EPA agrees that removal of facilities that will either retire or switch fuels by December 31, 2028 from the analysis resulted in an inaccurate baseline**.** For the final rule, EPA included all steam electric power plants projected to be in operation after December 31, 2023, in its analysis of the pollutant loadings, costs, and benefits under the baseline. See the *Supplemental TDD* and EPA's response in Code 7 for details. EPA also updated its methodology to better capture the transition from current wastewater treatment practices to practices that achieve the revised limitations, accounting for any differences in the timing of these changes under the baseline and final rule. Specifically, for the final rule analysis, EPA used annual average loadings projected during two distinct periods (2021-2028 and 2029-2047) within the overall analysis period (2021-2047) to analyze potential environmental changes and resulting estimated benefits. See Section 3.2 of BCA for details.
- EPA disagrees that its benefits cost analysis lacks transparency and does not adhere to best benefit cost analysis practices. Analyses detailed in the RIA and BCA follow EPA's Guidelines for Preparing Economic Analyses (U.S. EPA, 2010) and Office of Management and Budget Circular A-4. EPA used reasonable assumptions in assessing the likelihood of a facility's participation in the voluntary incentive program, as described in Section 3.1.5 of RIA and in the response to Code 41 (see section "Benefits Analysis Scope and General Assumptions"). EPA compared the annualized and discounted cost of implementing CP+LRTR between 2021 and 2025 (based on plant-specific schedules described in Section 3.1.3 of the RIA) or implementing membrane filtration in 2028. For the proposal and final analysis, EPA estimated VIP participants by comparing the two technologies and assuming that a plant owner would select the less costly of the two. EPA also considered additional information provided in public comment on potential VIP participation.
- EPA disagrees that incomplete monetization of health and other benefits render the comparison of benefits to costs invalid for Agency decision-making. EPA notes that the analysis of benefits fulfills the Agency's requirements under Executive Order 12866, but is not a statutory factor for Agency decision-making in determining effluent limitations and standards. Consistent with EPA's *Guidelines for Preparing Economic Analyses* and OMB Circular A-4, the Agency used the best methods and available data to identify, quantify, and wherever possible monetize, the benefits of the rule. For the final rule, EPA expanded its benefit analyses in response to comments received on the proposal, including accounting for additional benefit categories (e.g., human health benefits from changes in air emissions). As described in Chapter 2 of the final BCA, the Agency was unable to quantify some benefits

due to data limitations. The Agency describes these benefits in qualitative terms in the document and, if feasible, presents screening level assessment of potential benefits. Overall, EPA's benefit analysis provides a reasonable understanding of the magnitude of the major benefits estimated to result from the final rule. The Agency acknowledges that exclusion of some benefit categories may understate the total benefits of the final rule, particularly when compared to costs which are more readily quantifiable.

EO 12898 – Environmental Justice

EPA conducted various analyses to quantify the potential impacts of steam electric pollutants, including selenium, on aquatic species. For example, the Agency compared in-stream pollutant concentrations to the aquatic life National Recommended Water Quality Criteria (NRWQC) based on modeled concentrations in immediate receiving reaches and downstream reaches. Chapters 3 and 4 in the *Supplemental EA* and Chapter 3 in the *BCA* describe the methodology and results of these analyses. For a summary of selenium's effects, see Section 2 in the *Supplemental EA*.

The following table summarizes estimated selenium exceedances of the chronic and acute NRWQC to protect aquatic life during the two periods used for the analysis of the final rule benefits (see BCA for details and data files in DCN SE09370).

Scenario	**Number of reaches with modeled selenium concentration exceeding the aquatic life NRWQC (out of total 10,454 reaches)**			
	Period 1: 2021-2028		**Period 2: 2029-2047**	
	Acute	**Chronic**	**Acute**	**Chronic**
Baseline	3	18	3	3
Final Rule (Option A)	4	21	0	0

EPA's analysis shows very few of the modeled reaches exceeding the chronic selenium NRWQC in the baseline (approximately 0.2 percent), and even fewer reaches exceeding the acute selenium criterion for aquatic life EPA estimates that the final rule will have a small impact in the short term by increasing the number of reaches with exceedances slightly, when compared to baseline, and will eliminate baseline exceedances altogether in the longer term once all steam electric power plants have transitioned to technologies that meet the revised limitations. Based on these results, EPA assesses that the final rule is unlikely to have material effects on abundance or health of fish species targeted by subsistence fishers. EPA also notes that none of the reaches affected by stream electric discharges were estimated to exceed human health NRWQC for selenium (see Chapter 5 of BCA for detail).

EPA disagrees with the commenter that the Agency did not analyze and compare the distribution of forgone benefits of different options among communities. Chapter 14 of the proposed rule BCA presented two types of analyses to evaluate environmental justice (EJ) considerations: (1) a comparison of the socio-economic characteristics of the populations that live in proximity to steam electric power plants to state and national averages, and (2) the evaluation of human health effects and benefits that accrue to populations in different socioeconomic subgroups. EPA agrees, however, that more detailed analysis of the distribution of ecological effects and human health impacts among minority and/or low-income populations from changes in exposure to steam electric pollutants can help further inform the understanding of potential differences in the distribution of effects and benefits. Accordingly, in the final rule BCA, EPA expanded its EJ analysis to include the distributional impacts of changes in air emissions and to provide more details on the socioeconomic characteristics of communities living in proximity to reaches with changes in concentrations of pollutants that have at least one exceedance of human health criteria across the options and periods (antimony, arsenic, cadmium, cyanide, lead, manganese, and thallium) plus mercury.[93] These analyses are detailed in Chapter 14 of the BCA. The analysis shows that the EJ population subgroups are not excluded from the benefits associated with the regulatory options, including the final rule. In general, changes under the final rule are estimated to be small, and where distributional effects are present, these effects may affect low-income and minority populations disproportionately, including in cases where the final rule provides positive benefits.

For example, projected air quality changes under the final rule may disproportionately benefit minority and low-income populations based on the socioeconomic characteristics of populations of counties with changes in $PM_{2.5}$ and ozone levels during the period of analysis. Additionally, estimated forgone benefits related to water quality may disproportionately affect minority and subsistence fisher populations. However, the magnitude of the changes (positive and negative) and associated benefits (including forgone benefits) is small, relative to the baseline, both overall across the exposed population, and across socioeconomic and fisher subgroups.

The distributional effects of CCR operations and CCR part A rule requirements are outside the scope of this action. See Section IV.E.2 in the preamble for a discussion of the scope of the CCR Part A rule relative to the scope of the final rule. However, EPA generally agrees with the commenter that it is important to account for the timing of the transition of wastewater treatment practices when evaluating the environmental changes and resulting health benefits to populations living in proximity to steam electric power plants. For the final rule benefits and EJ analyses, EPA looked at changes in environmental conditions and resulting health effects over two periods: Period 1 (2021-2028), representing the period when the universe of plants would transition from current treatment practices to practices that achieve the revised limitations, and Period 2 (2029-2047), when the full universe of plants is projected to employ treatment practices that achieve the revised limitations. See Section 3.2 of the BCA for details.

EO 13045 – Protection of Children from Environmental Health Risks and Safety Risks

EPA notes that the analysis of children health impacts fulfills the Agency's requirements under Executive Order 13045, but is not a statutory factor for determining technology-based effluent limitations and standards, i.e., what is best available technology economically achievable as that

[93] EPA did not include selenium in this analysis because none of the reaches affected by stream electric discharges were estimated to exceed human health criteria for selenium (see Chapter 5 of BCA for detail).

term is used in Clean Water Act (CWA) section 301(b) after consideration of the factors specified under CWA section 304(b).

EPA disagrees that it did not address risks to children and disagrees further that the final rule will exacerbate environmental health risks to children. EPA analyzed the changes in children's exposure to lead and mercury and resulting changes in adverse health effects using the same methodology used in analyzing the 2015 rule. The results of this analysis, detailed in Chapter 5 of the BCA, show small effects to children, compared to the baseline which is the 2015 rule. While the final rule is estimated to result in small increases in IQ point loss compared to baseline, the aggregate increase is 19 IQ points over a population of approximately 1.6 million children for lead and an aggregate increase of 201 IQ points over approximately 226,000 infants for mercury. Additionally, EPA estimated that the final rule will have some positive health effects by reducing emissions of air pollutants in some years, when compared to the baseline. The resulting air quality improvements are estimated to benefit children's health by reducing infant mortality, lower and upper respiratory symptoms, and asthma, among other health effects. See Chapter 8 of the BCA for details.

EO 13175 – Consultation and Coordination with Indian Tribal Governments

EPA disagrees with the commenter's assertion that EPA violated EO 13175 and the Agency's own policy. According to EPA policy,[94] two types of rules require consultation with tribal officials early in the process before promulgation: (1) rules with tribal implications, substantial direct compliance costs on Indian tribal governments, and not required by statute, and (2) rules with tribal implications and that preempt tribal law. As the commenter notes, EPA consulted with tribal governments in developing the 2015 rule that promulgated the ELGs revised by the final rule. At the time of the 2015 rule, EPA assessed that none of the plants owned or operated by tribal governments would incur costs to comply with the ELG. This finding holds for the final rule, which provides cost savings relative to the 2015 rule baseline.

EPA policy lays out several mechanisms for identifying matters for consultations, including request by tribal government. EPA did not receive a request for consultation on this final rule from any of the tribal representatives it had consulted with when developing the 2015 rule.

EPA specifically addressed potential impacts on tribal populations as part of its analysis of environmental effects and benefits that was conducted for Executive Orders. This analysis includes impacts from changes occurring at all steam electric plants affected by the final rule (including the eight plants listed by the commenters). Specifically, EPA analyzed the distribution of environmental changes and their potential effects on tribal populations where data supported a distributional analysis. The results of this analysis, which are detailed in Chapter 14 of the BCA, show the potential for changes in source water quality for public water systems operated by tribal governments, as well as increased exposure to toxic pollutants (e.g., lead and mercury), via

[94] See Summary of Executive Order 13175 (https://www.epa.gov/laws-regulations/summary-executive-order-13175-consultation-and-coordination-indian-tribal) and EPA policy on consultation and coordination with Indian Tribes (https://www.epa.gov/sites/production/files/2013-08/documents/cons-and-coord-with-indian-tribes-policy.pdf).

consumption of self-caught fish. EPA estimates small environmental changes associated with changes in pollutant loadings for the final rule as compared to the baseline, including small changes in impacts to wildlife and humans. EPA also estimated that changes in pollutant emissions would result in net human health benefits in many regions of the United States and/or years within the period of analysis. While the Agency did not estimate the share of benefits accruing specifically to tribal populations, the analysis does show a disproportionate share of benefits accruing to minority populations, which include American Indian and Alaska Native peoples.

References

U.S. Environmental Protection Agency. (2010). *Guidelines for Preparing Economic Analyses*. (EPA 240-R-10-001).

U.S. Environmental Protection Agency. (2019). *Benefit and Cost Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*.

Appendix A

Comment Submittal Index Listing the Comment Submittals Ordered by DCN (and Affiliate Name) and Corresponding Comment Codes

DCN	Commenter	Affiliate	Comment Code Topics
EPA-HQ-OW-2009-0819-8285-A1	Anonymous		41
EPA-HQ-OW-2009-0819-8287-A1	Donald Shattuck		18
EPA-HQ-OW-2009-0819-8292-A1	Gary Hess		1, 3
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EPA-HQ-OW-2009-0819-8461-A1	Anonymous		41
EPA-HQ-OW-2009-0819-8288-A1	Kevin C. O'Brien	Prairie Research Institute, Illinois Sustainable Technology Center	9.b
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EPA-HQ-OW-2009-0819-8467-A1	Iliana Paul	Institute for Policy Integrity at New York University School of Law, et al.	41
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EPA-HQ-OW-2009-0819-8463-A1	Colton Fagundes	American Sustainable Business Council	27, 40
EPA-HQ-OW-2009-0819-8490-A1	Regina Rodriguez, Ph.D.	Carbonxt	14, 18
EPA-HQ-OW-2009-0819-8290-A1	Usha-Maria Turner	Oklahoma Gas and Electric Company (OG&E)	3, 3.a, 21.a
EPA-HQ-OW-2009-0819-8306-A1	Ron Eller and Jim Zerefos	Tinuum Group, LLC	3, 13, 28
EPA-HQ-OW-2009-0819-8312-A1	G. Tracy Mehan, III	American Water Works Association (AWWA)	3, 36, 41
EPA-HQ-OW-2009-0819-8317-A1	Patti Hershey	Lower Colorado River Authority (LCRA)	1, 3.a, 21.a
EPA-HQ-OW-2009-0819-8321-A1	Angie Rosser	West Virginia Rivers Coalition (WV Rivers), et al.	1, 5, 27

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EPA-HQ-OW-2009-0819-8464-A2	Ed Stone	Maryland Department of the Environment	4, 9, 21.a
EPA-HQ-OW-2009-0819-8291-A1	Rachel Procter	Consumers Energy Company (CE)	3.a, 7, 8, 9.a
EPA-HQ-OW-2009-0819-8294-A1	Jeffrey L. West	Xcel Energy Inc.	7, 9.a, 10, 38
EPA-HQ-OW-2009-0819-8315-A1	American Coal Council (ACC)	American Coal Council (ACC)	15, 21.a, 33, 43
EPA-HQ-OW-2009-0819-8324-A1	Eric C. Massey	Arizona Public Service Company	3, 3.a, 4, 21.a
EPA-HQ-OW-2009-0819-8459-A1	James S. Andrews	GSP Merrimack LLC	7, 9, 9.b, 34
EPA-HQ-OW-2009-0819-8462-A1	Jennifer Peters, et al.	Clean Water Action, et al.	9, 17, 23, 34
EPA-HQ-OW-2009-0819-8298-A1	GenOn Holdings, Inc. (GenOn)	GenOn Holdings, Inc. (GenOn)	3.a, 9.a, 9.b, 21.a, 33
EPA-HQ-OW-2009-0819-8310-A1	Major L. Clark, III and David Rostker	Office of Advocacy, U. S. Small Business Administration	3, 5, 9.b, 14, 15
EPA-HQ-OW-2009-0819-8327-A1	Caitlin McHale	National Mining Association (NMA)	15, 21.a, 33, 40, 43
EPA-HQ-OW-2009-0819-8460-A1	Cynthia E. Vodopivec	Vistra Energy Corp. ("Vistra")	9, 9.a, 9.b, 21.a, 43
EPA-HQ-OW-2009-0819-8308-A1	Mike Krumland	Nebraska Public Power District (NPPD)	9.a, 9.b, 21.a, 23, 33, 37
EPA-HQ-OW-2009-0819-8309-A1	Patrick O'Loughlin	Buckeye Power, Inc.	3, 9.a, 21.a, 33, 38, 43
EPA-HQ-OW-2009-0819-8322-A1	Jane H. Hood	Santee Cooper	7, 9, 9.a, 9.b, 33, 36
EPA-HQ-OW-2009-0819-8323-A1	Josh Shapiro, Brian E. Frosh, Kwame Raoul, Dana Nessel, and Thomas J. Donovan, Jr.	Attorneys General of Maryland, Pennsylvania, Illinois, Michigan, and Vermont	1, 3, 9, 9.a, 9.b, 38
EPA-HQ-OW-2009-0819-8470-A2	Thomas Weissinger	Talen Energy	7, 9.a, 9.b, 33, 38, 40
EPA-HQ-OW-2009-0819-8289-A1	Clark Harrison	Purestream Services, LLC	5, 9.a, 11, 18, 21.a, 25, 34
EPA-HQ-OW-2009-0819-8297-A1	Jennifer McIvor	Berkshire Hathaway Energy Company	3, 3.a, 19, 21.a, 33, 38, 43
EPA-HQ-OW-2009-0819-8305-A1	Michael P. Alaimo	Clean Fuels Michigan, et al.	3, 9.b, 17, 23, 27, 28, 34
EPA-HQ-OW-2009-0819-8318-A1	Toni Presnell	Oglethorpe Power Corporation	3, 9, 9.a, 9.b, 33, 36, 43
EPA-HQ-OW-2009-0819-8302-A1	David A. Friedman	FirstEnergy Corporation	8, 9.a, 9.b, 11, 13, 21.a, 33, 36
EPA-HQ-OW-2009-0819-8319-A1	Dorothy Kellogg	National Rural Electric Cooperative Association (NRECA)	4, 9.a, 9.b, 13, 17, 21.a, 36, 43
EPA-HQ-OW-2009-0819-8325-A1	Bill Matthews	Cleco Corporate Holdings LLC	3, 3.a, 4, 9.a, 9.c, 11, 21.a, 36
EPA-HQ-OW-2009-0819-8329-A1	Bethany Davis Noll	Institute for Policy Integrity, New York University School of Law	1, 3, 9.a, 9.b, 9.c, 34, 41, 44

DCN	Commenter	Affiliate	Comment Code Topics
EPA-HQ-OW-2009-0819-8330-A2	Michelle Bloodworth	America's Power	3, 9.b, 9.c, 15, 21.a, 23, 36, 43
EPA-HQ-OW-2009-0819-8316-A1	Matthew Goddard	DTE Energy (DTE)	4, 9.a, 15, 19, 21.a, 33, 34, 36, 37
EPA-HQ-OW-2009-0819-8320-A1	Nathan Craig	Duke Energy	3.a, 4, 9.b, 15, 17, 21.a, 36, 37, 43
EPA-HQ-OW-2009-0819-8326-A1	Martha Thomsen, Baker Botts L.L.P.	Cross-Cutting Issues Group (CCIG)	3, 9.a, 15, 21.a, 28, 33, 36, 37, 43
EPA-HQ-OW-2009-0819-8328-A1	Carolyn Slaughter	American Public Power Association (APPA)	3.a, 4, 9.a, 9.b, 17, 21.a, 22, 33, 34, 36, 43
EPA-HQ-OW-2009-0819-8331-A1	Doug Brown	Office of Public Utilities dba as City Water Light and Power (CWLP), City of Springfield, Illinois	1, 3, 7, 9, 9.a, 9.b, 11, 29, 33, 38, 40, 43
EPA-HQ-OW-2009-0819-8314-A1	Alexander Bond	Edison Electric Institute (EEI)	4, 7, 9.a, 9.b, 11, 15, 17, 19, 21.a, 33, 34, 36, 43
EPA-HQ-OW-2009-0819-8474-A2	Ranajit Sahu	Consultant to EarthJustice, et al.	4, 9.c, 11, 15, 17, 18, 19, 21.a, 22, 23, 33, 36, 37, 43
EPA-HQ-OW-2009-0819-8457-A1	Donna Hill	Southern Company Services, Inc.	3, 3.a, 4, 9.a, 9.b, 11, 14, 15, 17, 21.a, 33, 34, 35, 36, 37, 43
EPA-HQ-OW-2009-0819-8458-A1	Rebecca C. Tolene	Tennessee Vallley Authority (TVA)	3, 3.a, 4, 7, 9, 9.b, 11, 15, 17, 21.a, 21.b, 22, 33, 34, 36, 43
EPA-HQ-OW-2009-0819-8293-A1	Robert Chapman	Electric Power Research Institute, Inc. (EPRI)	3, 9.b, 11, 13, 14, 15, 17, 18, 19, 20, 21.a, 21.b, 22, 23, 28, 37, 41, 43
EPA-HQ-OW-2009-0819-8465-A1	Megan Kimball	Southern Environmental Law Center et al.	1, 3, 4, 9, 9.a, 9.b, 9.c, 10, 11, 13, 14, 15, 17, 23, 27, 28, 33, 34, 36, 41, 44
EPA-HQ-OW-2009-0819-8473-A1	Thomas Cmar	Earthjustice et al.	1, 3, 3.b, 4, 9, 9.a, 9.b, 9.c, 10, 11, 14, 15, 17, 18, 21.a, 23, 27, 28, 29, 33, 34, 36, 40, 41, 44
EPA-HQ-OW-2009-0819-8456-A1	Elizabeth E. Aldridge, Hunton Andrews Kurth	Utility Water Act Group (UWAG)	1, 3, 3.a, 4, 5, 7, 8, 9, 9.a, 9.b, 13, 15, 17, 18, , 20, 21.a, 21.b, 22, 23, 28, 29, 33, 34, 35, 36, 37, 40, 41, 43