6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 423

[EPA–HQ–OW–2009–0819; FRL–10002–04–OW]

RIN 2040-AF77

Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (the EPA or the Agency) is proposing a regulation to revise the technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category applicable to flue gas desulfurization (FGD) wastewater and bottom ash (BA) transport water. This proposal is estimated to save approximately $175 million dollars annually in pre-tax compliance costs and $137 million dollars annually in social costs as a result of less costly FGD wastewater technologies that could be used with the proposed relaxation of the Steam Electric Power Generating Effluent Guidelines 2015 rule (the 2015 rule) selenium limitation; less costly BA transport water technologies made possible by the proposed relaxation of the 2015 rule's zero discharge limitations; a two-year extension of compliance timeframes for meeting FGD wastewater limits, and additional proposed subcategories for both FGD wastewater and BA transport water. EPA also believes that participation in the voluntary incentive program would further reduce the pollutants that these steam electric facilities discharge in FGD wastewater by approximately 105 million pounds per year.

DATES: *Comments.* Comments on this proposed rule must be received on or before **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**

Public Hearing. The EPA will conduct an online public hearing about today's proposed rule on December 19, 2019. Following a brief presentation by EPA personnel, the Agency will accept oral comments that will be limited to three (3) minutes per commenter. The hearing will be recorded and transcribed, and the EPA will consider all of the oral comments provided, along with the written public comments submitted via the docket for this rulemaking. To register for the hearing, please visit the EPA's website at *https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2019-proposed-revisions*

ADDRESSES: Submit your comments on the proposed rule, identified by Docket No. EPA-HQ-OW-2009-0819, by one of the following methods:

- Federal eRulemaking Portal: *https://www.regulations.gov/* (preferred method). Follow the online instructions for submitting comments.
- Email: a-and-r-docket@epa.gov. Include Docket ID No. EPA-HQ-OW-2009-0819 (specify the applicable docket number) in the subject line of the message.
- Fax: (202) 566-9744. Attention Docket ID No. EPA-HQ-OW-2009-0819 (specify the applicable docket number).
- Mail: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA-HQ-OW-2009-0819, Office of Science and Technology Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- Hand Delivery / Courier: EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations are 8:30 a.m. – 4:30 p.m., Monday – Friday (except Federal Holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov/*, including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, *see* the “Public Participation” heading of the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For technical information, contact Richard Benware, Engineering and Analysis Division, Telephone: 202–566–1369; Email: *benware.richard@epa.gov*. For economic information, contact James Covington, Engineering and Analysis Division, Telephone: 202–566–1034; Email: *covington.james@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble Acronyms and Abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines terms and acronyms used in Appendix A.

Supporting Documentation. The rule proposed today is supported by a number of documents including:

- *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-R-19-009. This report summarizes the technical and engineering analyses supporting the proposed rule. The Supplemental TDD presents the EPA’s updated analyses supporting the proposed revisions to FGD wastewater and BA transport water. These updates include additional data collection that has occurred since the publication of the 2015 rule, updates to the industry (e.g., retirements, updates to FGD treatment and BA handling), cost methodologies, pollutant removal estimates, corresponding nonwater quality environmental impacts associated with updated FGD and BA methodologies, and calculation of the proposed effluent limitations. Except for the updates described in the

Supplemental TDD, the *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2015 TDD, Document No. EPA-821-R-15-007) is still applicable and provides a more complete summary the EPA's data collection, description of the industry, and underlying analyses supporting the 2015 rule.

- *Supplemental Environmental Assessment for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental EA), Document No. EPA-821-R-19-010. This report summarizes the potential environmental and human health impacts that are estimated to result from implementation of the proposed revisions to the 2015 rule.
- *Benefit and Cost Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA Report), Document No. EPA-821-R-19-011. This report summarizes estimated societal benefits and costs that are estimated to result from implementation of the proposed revisions to the 2015 rule.
- *Regulatory Impact Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA), Document No. EPA-821-R-19-012. This report presents a profile of the steam electric power generating industry, a summary of estimated costs and impacts associated with the proposed revisions to the 2015 rule, and an assessment of the potential impacts on employment and small businesses.

- *Docket Index for the Proposed Revisions to the Steam Electric ELGs.* This document provides a list of the additional memoranda, references, and other information relied upon by the EPA for the proposed revisions to the ELGs.

Organization of this Document. The information in this preamble is organized as follows:

I. Executive Summary

A. Purpose of Rule

Coal-fired facilities are impacted by several environmental regulations. One of these regulations, the Steam Electric Power Generating ELGs was promulgated in 2015 (80 Fed. Reg.

67838; November 3, 2015) and applies to the subset of the electric power industry where "generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel (coal, oil, gas), fuel derived from fossil fuel (e.g., petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam-water system as the thermodynamic medium." (40 CFR 423.10). The 2015 rule addressed discharges from flue gas desulfurization (FGD) wastewater, fly ash transport water, bottom ash transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non-chemical metal cleaning wastes.

In the few years since the steam electric ELGs were revised in 2015, steam electric facilities have installed more affordable technologies which are capable of removing a similar amount of pollution as those which existed in 2015. This proposal would revise requirements for two of the waste streams addressed in the 2015 rule: bottom ash (BA) transport water and flue gas desulfurization (FGD) wastewater – two of the facilities' largest sources of wastewater – while reducing industry costs as compared to the costs of the 2015 rule's controls. This proposal does not seek to revise the other waste streams covered by the 2015 rule.

B. Summary of Proposed Rule

For existing sources that discharge directly to surface water, with the exception of the subcategories discussed below, the proposed rule would establish the following effluent limitations based on Best Available Technology Economically Achievable (BAT):

- For flue gas desulfurization wastewater, there are two sets of proposed BAT limitations. The first set of limitations is a numeric effluent limitation on Total Suspended Solids (TSS) in the discharge of FGD wastewater. The second set of BAT limitations comprises numeric effluent limitations on mercury, arsenic, selenium, and nitrate/nitrite as nitrogen in the discharge of FGD wastewater.

- 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.

The proposed rule includes separate requirements for the following subcategories: high flow facilities, low utilization boilers, and boilers retiring by 2028. The proposed rule does not seek to change the existing subcategories for oil-fired boilers and small generating units (50 MW or less) from the 2015 rule. For high flow facilities (FGD wastewater flows over four 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) or low utilization boilers (876,000 MWh per year or less), the proposed rule would establish the second set of BAT limitations in the discharge of FGD wastewater as numeric effluent limitations only on mercury and arsenic (and not on selenium and nitrate/nitrite as nitrogen). For low utilization boilers, the proposed rule would establish BAT limitations for BA transport water for TSS, and would also include standards for implementation of a best management practices (BMP) plan. For oil-fired boilers, small boilers (50 MW or less), and boilers retiring by 2028, the proposed rule would establish BAT limitations for TSS in FGD wastewater and bottom ash transport water.

The proposed rule would establish a voluntary incentives program that provides the certainty of more time (until December 31, 2028) for facilities to implement new standards and limitations, if they adopt additional process changes and controls that achieve more stringent limitations on mercury, arsenic, selenium, nitrate/nitrite, bromide, and total dissolved solids in FGD wastewater. The optional program offers environmental protections beyond those achieved by the proposed BAT limitations, while providing facilities that opt into the program more flexibility (such as additional time) than the current voluntary incentives program.

For indirect discharges (i.e., discharges to publicly owned treatment works), the proposed rule establishes pretreatment standards for existing sources that are the same as the BAT limitations, except for TSS, where there is no pass through of pollutants at POTWs.

Where BAT limitations in this rule are more stringent than previously established BPT limitations, the EPA proposes that those limitations do not apply until a date determined by the permitting authority that is as soon as possible on or after November 1, 2020, but that is no later than December 31, 2023 (for BA transport water) or December 31, 2025 (for FGD wastewater).

C. Summary of Costs and Benefits

The EPA has estimated costs and benefits of four different regulatory options. The 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, and will save $166.2 million per year in social costs and between $28.4 million and $74.4 million in benefits, using a seven percent discount. Table XV–1 summarizes the benefits and social costs for the four regulatory options at a three percent discount rates. The EPA's analysis reflects the Agency's understanding of the actions steam electric facilities will take to meet the limitations and standards in the final rule. The EPA based its analysis on a baseline that reflects the expected impacts of announced retirements and fuel conversions, impacts of relevant rules such as the Coal Combustion Residuals (CCR) rule that the Agency promulgated in April 2015 and the Affordable Clean Energy Rule (ACE) that the Agency promulgated in 2019, and the full implementation of the 2015 rule. The EPA understands that these modeled results have uncertainty and that the actual costs could be higher or lower than estimated. The current estimate reflects the best data and analysis available at this time. For additional information, see Sections V and VIII.

II. Public Participation

Submit your comments, identified by Docket ID No. EPA-HQ-OW-2009-0819, at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e. on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets*.

III. General Information

A. Does this action apply to me?

Entities potentially regulated by any final rule following this action include:

Category	Example of regulated entity	North American Industry Classification System (NAICS) Code
Industry	Electric Power Generation Facilities – Electric Power Generation	22111
	Electric Power Generation Facilities – Fossil Fuel Electric Power Generation	221112

This section is not intended to be exhaustive, but rather provides a guide regarding entities likely to be regulated by any final rule following this action. Other types of entities that do not meet the above criteria could also be regulated. To determine whether your facility is regulated by any final rule following this action, you should carefully examine the applicability criteria listed in 40 CFR 423.10 and the definitions in 40 CFR 423.11 of the 2015 rule. If you still have questions regarding the applicability of any final rule following this action to a particular entity, consult the person listed for technical information in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What action is the agency taking?

The agency is proposing to revise certain Best Available Technology Economically Achievable (BAT) effluent limitations guidelines and pretreatment standards for existing sources in the steam electric power generating point source category that apply to FGD wastewater and BA transport water.

C. What is the agency's authority for taking this action?

The EPA is proposing to promulgate this rule under the authority of sections 301, 304, 306, 307, 308, 402, and 501 of the Clean Water Act (CWA), 33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342, and 1361.

D. What are the monetized incremental costs and benefits of this action?

This action is estimated to save $136.3 million per year in social costs and result in between $14.8 million and $68.5 million in benefits, using a 3 percent discount rate. Using a 7 percent discount rate, the estimated savings are $166.2 million per year and benefits are between $28.4 million and $74.4 million.

IV. Background

A. Clean Water Act

Among its core provisions, the CWA prohibits the discharge of pollutants from a point source to waters of the U.S., except as authorized under the CWA. Under section 402 of the CWA, 33 U.S.C. 1342, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA establishes a dual approach for these permits: (1) technology-based controls that establish a floor of performance for all dischargers, and (2) water quality-based effluent limitations, where the technology-based effluent limitations are insufficient to meet applicable water quality standards (WQS). As the basis for the technology-based controls, the CWA authorizes the EPA to establish national technology-based effluent limitations guidelines and new source performance standards for discharges into waters of the United States from categories of point sources (such as industrial, commercial, and public sources).

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 sections 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. Pretreatment standards are designed to ensure that wastewaters from direct and indirect industrial dischargers are subject to similar levels of treatment. *See* CWA section 301(b), 33 U.S.C. 1311(b). In addition, POTWs are required to implement local treatment limitations applicable to their industrial indirect dischargers to satisfy any local requirements. *See* 40 CFR 403.5.

Direct dischargers (those discharging to waters of the U.S. rather than to a POTW) must comply with effluent limitations in NPDES permits. Indirect dischargers, who discharge through POTWs, must comply with pretreatment standards. Technology-based effluent limitations and standards in NPDES permits are derived from effluent limitations guidelines (CWA sections 301 and 304, 33 U.S.C. 1311 and 1314) and new source performance standards (CWA section 306, 33 U.S.C. 1316) promulgated by the EPA, or are based on best professional judgment (BPJ) where EPA has not promulgated an applicable effluent limitation guideline or new source performance standard (CWA section 402(a)(1)(B), 33 U.S.C. 1342(a)(1)(B)). Additional limitations are also required in the permit where necessary to meet WQS. CWA section 301(b)(1)(C), 33 U.S.C. 1311(b)(1)(C). The ELGs are established by EPA regulation for categories of industrial dischargers and are based on the degree of control that can be achieved using various levels of pollution control technology, as specified in the Act (e.g., BPT, BCT, BAT; *see* below).

EPA promulgates national ELGs for industrial categories for three classes of pollutants: (1) conventional pollutants (total suspended solids (TSS), oil and grease, biochemical oxygen demand (BOD5), fecal coliform, and pH), as outlined in CWA section 304(a)(4), 33 U.S.C. 1314(a)(4), and 40 CFR 401.16; (2) toxic pollutants (e.g., toxic metals such as arsenic, mercury, selenium, and chromium; toxic organic pollutants such as benzene, benzo-a-pyrene, phenol, and naphthalene), as outlined in CWA section 307(a), 33 U.S.C. 1317(a); 40 CFR 401.15 and 40 CFR part 423, appendix A; and (3) nonconventional pollutants, which are those pollutants that are not categorized as conventional or toxic (e.g., ammonia-N, phosphorus, and total dissolved solids (TDS)).

B. Relevant Effluent Guidelines

The EPA establishes ELGs based on the performance of well-designed and well-operated control and treatment technologies. The legislative history also supports that the EPA need not consider water quality impacts on individual water bodies as the guidelines are developed; *see* Statement of Senator Muskie (principal author) (October 4, 1972), reprinted in Legislative History of the Water Pollution Control Act Amendments of 1972, at 170. (U.S. Senate, Committee on Public Works, Serial No. 93–1, January 1973).

There are four types of standards applicable to direct dischargers and two types of standards applicable to indirect dischargers. The three standards relevant to this rulemaking are described in detail below.

1. Best Practicable Control Technology Currently Available (BPT)

Traditionally, the EPA establishes effluent limitations based on BPT by reference to the average of the best performances of facilities within the industry, grouped to reflect various ages, sizes, processes, or other common characteristics. The EPA promulgates BPT effluent limitations for conventional, toxic, and nonconventional pollutants. In specifying BPT, the EPA looks at a number of factors. The EPA first considers the cost of achieving effluent reductions in relation to the effluent reduction benefits. The Agency also considers the age of equipment and facilities, the processes employed, engineering aspects of the control technologies, any required process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. *See* CWA section 304(b)(1)(B), 33 U.S.C. 1314(b)(1)(B). If, however, existing performance is uniformly inadequate, the EPA may establish limitations based on higher levels of control than those currently in place in an industrial category, when based on an Agency determination that the technology is available in another category or subcategory and can be practically applied.

2. Best Available Technology Economically Achievable (BAT)

BAT represents the second level of control for direct discharges of toxic and nonconventional pollutants. As the statutory phrase intends, the EPA considers the technological availability and the economic achievability in determining what level of control represents BAT. CWA section 301(b)(2)(A), 33 U.S.C. 1311(b)(2)(A). Other statutory factors that the EPA must consider in assessing BAT are the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. CWA section 304(b)(2)(B), 33 U.S.C. 1314(b)(2)(B); *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998). The Agency retains considerable discretion in assigning the weight to be accorded each of these required consideration factors. *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1045 (D.C. Cir. 1978). Generally, the EPA determines economic achievability based on the effect of the cost of compliance with BAT limitations on overall industry and subcategory (if applicable) financial conditions. 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 subcategory or category, bench scale or pilot studies, or foreign facilities. *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). BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice. *See Am. Frozen Food Inst.*, 539 F.2d at 132, 140;

Reynolds Metals Co. v. EPA, 760 F.2d 549, 562 (4th Cir. 1985); *Cal. & Hawaiian Sugar Co. v. EPA*, 553 F.2d 280, 285–88 (2nd Cir. 1977).

One way that EPA may take into account differences within an industry when establishing BAT limitations is through subcategorization. The Supreme Court has recognized that the substantive test for subcategorizing an industry is the same as that which applies to establishing fundamentally different factor variances – i.e., whether the plants are different with respect to relevant statutory factors. *See Chem. Mfrs. Ass'n v. EPA*, 870 F.2d 177, 214 n.134 (5th Cir. 1989) (citing *Chem. Mfrs. Ass'n v. NRDC*, 470 U.S. 116, 119-22, 129-34 (1985)). Courts have stated that there need only be a rough basis for subcategorization. See *Chem. Mfrs. Ass'n v. EPA*, 870 F.2d at 215 n.137 (summarizing cases).

3. Pretreatment Standards for Existing Sources (PSES)

Section 307(b) of the CWA, 33 U.S.C. 1317(b), authorizes the EPA to promulgate pretreatment standards for discharges of pollutants to POTWs. PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical 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. 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. Conf. Rep. No. 95–830, at 87 (1977), reprinted in U.S. Congress. Senate Committee on Public Works (1978), A Legislative History of the CWA of 1977, Serial No. 95–14 at 271 (1978). The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR

403. These regulations establish pretreatment standards that apply to all non-domestic dischargers. *See* 52 FR 1586 (January 14, 1987).

C. 2015 rule

The EPA, on September 30, 2015, finalized a rule revising the regulations for the Steam Electric Power Generating point source category (40 CFR Part 423) (hereinafter the "2015 rule"). The rule set the first federal limitations on the levels of toxic metals in wastewater that can be discharged from steam electric facilities, based on technology improvements in the steam electric power industry over the preceding three decades. Prior to the 2015 rule, regulations for the industry had been last updated in 1982.

New technologies for generating electric power and the widespread implementation of air pollution controls over the last 30 years have altered existing wastewater streams or created new wastewater streams at many steam electric facilities, particularly coal-fired facilities. Discharges of these wastestreams include arsenic, lead, mercury, selenium, chromium, and cadmium. Many of these toxic pollutants, once in the environment, remain there for years, and continue to cause impacts.

The 2015 rule addressed effluent limitations and standards for multiple wastestreams generated by new and existing steam electric facilities: BA transport water, combustion residual leachate, FGD wastewater, flue gas mercury control wastewater, fly ash (FA) transport water, and gasification wastewater. The rule required most steam electric facilities to comply with the effluent limitations "as soon as possible" after November 1, 2018, and no later than December 31, 2023. Within that range, except for indirect dischargers, the particular compliance date(s) for each facility would be determined by the facility's National Pollutant Discharge Elimination System permit, which is typically issued by a state environmental agency.

On an annual basis, the 2015 rule was projected to reduce the amount of metals defined in the Act as toxic pollutants, nutrients, and other pollutants that steam electric facilities are allowed to discharge by 1.4 billion pounds and reduce water withdrawal by 57 billion gallons. At the time, the EPA estimated annual compliance costs for the final rule to be $480 million (in 2013 dollars) and estimated benefits associated with the rule to be $451 to $566 million (in 2013 dollars).

D. Legal Challenges, Administrative Petitions, Section 705 Action, Postponement Rule, and Reconsideration of Certain Limitations and Standards

Seven petitions for review of the 2015 rule were filed in various circuit courts by the electric utility industry, environmental groups, and drinking water utilities. These petitions were consolidated in the U.S. Court of Appeals for the Fifth Circuit, *Southwestern Electric Power Co., et al. v. EPA.*[1] On March 24, 2017, the Utility Water Act Group (UWAG) submitted to the EPA an administrative petition for reconsideration of the 2015 rule. Also, on April 5, 2017, the Small Business Administration (SBA) submitted an administrative petition for reconsideration of the final rule.

On April 25, 2017, the EPA responded to these petitions by publishing a postponement of the 2015 rule compliance deadlines that had not yet passed, under Section 705 of the Administrative Procedure Act (APA). This Section 705 Action drew multiple legal challenges.[2] The Administrator then signed a letter on August 11, 2017, announcing his decision to conduct a rulemaking to potentially revise the new, more stringent BAT effluent limitations and

[1] Case No. 15-60821.

[2] *See Clean Water Action. v. EPA*, No. 17-0817 (D.D.C.), appeal docketed, No. 18-5149 (D.C. Cir.); *see also Clean Water Action. v. EPA*, No. 18-60619 (5th Cir.) (case dismissed for lack of jurisdiction on October 18, 2018).

pretreatment standards for existing sources in the 2015 rule that apply to FGD wastewater and BA transport water. The Fifth Circuit subsequently granted EPA's request to sever and hold in abeyance aspects of the litigation related to those limitations and standards. With respect to the remaining claims related to limitations applicable to legacy wastewater and leachate, which are not at issue in this proposed rulemaking, the Fifth Circuit issued a decision on April 12, 2019, vacating those limitations as arbitrary and capricious under the Administrative Procedure Act and unlawful under the CWA, respectively. The EPA plans to address this vacatur in a subsequent action.

In September 2017, the EPA finalized a rule, using notice-and-comment procedures, postponing the earliest compliance dates for the new, more stringent BAT effluent limitations and PSES for FGD wastewater and BA transport water in the 2015 rule, from November 1, 2018 to November 1, 2020. The EPA also withdrew its prior action taken pursuant to Section 705 of the APA. The rule received multiple legal challenges, but EPA prevailed, and the courts did not sustain any of them.[3]

E. Other Ongoing Rules Impacting the Steam Electric Sector

1. Clean Power Plan (CPP) and Affordable Clean Energy (ACE)

The final 2015 CPP established carbon dioxide (CO2) emission guidelines for fossil-fuel fired facilities based in part on shifting generation at the fleet-wide level from one type of energy source to another. On February 9, 2016, the U.S. Supreme Court stayed implementation of the CPP pending judicial review. *West Virginia* v. *EPA*, No. 15A773 (S.Ct. Feb. 9, 2016).

[3] *See Center for Biological Diversity v. EPA*, No. 18-cv-00050 (D. Ariz. filed Jan. 20, 2018); *see also Clean Water Action. v. EPA*, No. 18-60079 (5th Cir.). On October 29, 2018, the District of Arizona case was dismissed upon EPA's motion to dismiss for lack of jurisdiction, and on August 28, 2019, the Fifth Circuit denied the petition for review of the postponement rule.

On June 19, 2019, the EPA issued the ACE rule, an effort to provide existing coal-fired electric utility generating units (EGUs) with achievable and realistic standards for reducing greenhouse gas emissions. This action was finalized in conjunction with two related, but separate and distinct rulemakings: (1) the repeal of the CPP, and (2) revised implementing regulations for ACE, ongoing emission guidelines, and all future emission guidelines for existing sources issued under the authority of Clean Air Act section 111(d). ACE provides states with new emission guidelines that will inform the state's development of standards of performance to reduce CO2 emissions from existing coal-fired EGUs consistent with the EPA's role as defined in the CAA.

ACE establishes heat rate improvement (HRI), or efficiency improvement, as the best system of emissions reduction (BSER) for CO_2 from coal-fired EGUs.[4] By employing a broad range of HRI technologies and techniques, EGUs can more efficiently generate electricity with less carbon intensity.[5] The BSER is the best technology or other measure that has been adequately demonstrated to improve emissions performance for a specific industry or process (a "source category"). In determining the BSER, the EPA considers technical feasibility, cost, non-air quality health and environmental impacts, and energy requirements. The BSER must be applicable to, at, and on the premises of an affected facility. ACE lists six HRI "candidate technologies," as well as additional operating and maintenance (O&M) practices.[6] For each candidate technology, the EPA has provided information regarding the degree of emission

[4] Heat rate is a measure of the amount of energy required to generate a unit of electricity.

[5] An improvement to heat rate results in a reduction in the emission rate of an EGU (in terms of CO_2 emissions per unit of electricity produced).

[6] These six technologies are: (1) Neural Network/Intelligent Sootblowers, (2) Boiler Feed Pumps, (3) Air Heater and Duct Leakage Control, (4) Variable Frequency Drives, (5) Blade Path Upgrade (Steam Turbine), and (6) Redesign/Replace Economizer.

limitation achievable through application of the BSER as ranges of expected improvement and costs.

The 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). As noted in the ACE RIA, while the final repeal of the CPP has been promulgated, the business-as-usual economic conditions achieved the carbon reductions laid out in the final CPP. The EPA used the IPM version 6 to analyze today's proposal to be consistent with the base case analyses done for the ACE final rule. The Agency also performed a sensitivity analysis on the proposed Option 2, following promulgation of the ACE final rule, that estimates the impacts of the proposed option relative to a baseline that includes the ACE rule. A similar sensitivity analysis was not conducted for Option 4. The EPA intends to perform IPM runs with the most up-to-date version of the model available for the final rule. *See* additional discussion of IPM in Section VIII of this preamble.

2. Coal Combustion Residuals (CCR)

On April 17, 2015, the Agency published the Disposal of Coal Combustion Residuals from Electric Utilities final rule. This rule finalized national regulations to provide a comprehensive set of requirements for the safe disposal of CCRs, commonly known as coal ash, from coal-fired facilities. The final CCR rule was the culmination of extensive study on the effects of coal ash on the environment and public health. The rule established technical requirements for CCR landfills and surface impoundments under subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste.

These regulations addressed coal ash disposal, including regulations designed to prevent leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the CCR rule set out recordkeeping and reporting requirements as well as the requirement for each facility to establish and post specific information to a publicly-accessible website. This final CCR rule also supported the responsible recycling of CCRs by distinguishing safe, beneficial use from disposal.

As explained in the 2015 rule, the ELGs and CCR rules may affect the same boiler or activity at a facility. That being the case, 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. The coordination of the two rules continues to be a consideration in the development of today's proposal. The EPA's analysis of this proposal incorporates the same approach used in the 2015 rule to estimate how the CCR rule may affect surface impoundments and the ash handling systems and FGD treatment systems that send wastes to those impoundments. However, as a result 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), amendments to the CCR rule are being proposed which would establish a deadline of August 2020 by which all unlined surface impoundments[7] must cease receiving waste, subject to certain exceptions. This would not impact the ability of facilities to install new, composite lined surface impoundments. This CCR proposal and accompanying background documents are available at *www.regulations.gov* Docket EPA-HQ-OLEM-2019-0172, and comments on that proposal should be submitted to that docket.

In order to account for the CCR rule proposed amendments in this proposed rule, the EPA conducted a sensitivity analysis to determine how the closure of unlined surfaced

[7] Due to the Court vacatur of 40 CFR Part 257.71(a)(1)(i) (provision for clay-lined surface impoundments) clay-lined surface impoundments are currently also considered unlined.

impoundments would impact the compliance cost and pollutant loading estimates for today's proposal. After conducting this sensitivity analysis, the EPA found that the capital and operation and maintenance compliance cost estimates decrease by 50 to 60 percent and the total industry pollutant loadings decrease by five percent (*see* DCN SE07233).

The EPA solicits comment on the overlap between these two rules, including whether the Agency's cost benefit and regulatory impact analyses appropriately capture the overlap of the two rules, and ways that the Agency could harmonize the timelines for regulatory requirements. The Agency also solicits comment on the extent to which facilities have chosen to construct new composite lined surface impoundments for the treatment of bottom ash transport water or FGD wastewater. Comments on the intersection of the two rules should be submitted to both dockets.

F. Scope of this Proposed Rulemaking

This proposal, if finalized, would revise the new, more stringent BAT effluent limitations guidelines and pretreatment standards for existing sources in the 2015 rule that apply to FGD wastewater and BA transport water. It does not propose otherwise to amend (nor is the EPA requesting comment on) the effluent limitations guidelines and standards for other wastes discharged by the steam electric power generating point source category. The EPA plans to address the Court's remand in *Southwestern Elec. Power Co. v. EPA* with respect to the limitations for leachate and legacy wastewater in a subsequent action.

V. Steam Electric Power Generating Industry Description

A. General Description of Industry

The EPA provided a general description of the steam electric power generating industry in the 2013 proposed rule and the 2015 rule, and has continued to collect information and update that profile. The previous descriptions reflected the known information about the universe of steam electric facilities and incorporated applicable final environmental regulations at that time. For this proposal, as described in the Supplemental TDD Section 3, the EPA has revised its description of the steam electric power generating industry (and its supporting analyses) to incorporate major changes such as additional retirements, fuel conversions, ash handling conversions, wastewater treatment updates, and updated information on capacity utilization.[8] The analyses supporting this proposal use an updated baseline that incorporates these changes in the industry. The analyses then compare the effect of today's proposed rules for FGD wastewater and bottom ash transport water to the effect of the 2015 rule's limitations for FGD wastewater and BA transport water on the industry as it exists today.

B. Current Market Conditions in the Electricity Generation Sector

Market conditions in the electricity generation sector have changed significantly and rapidly in the past decade. These changes include availability of abundant and inexpensive natural gas, emergence of alternative fuel technologies, and continued aging of coal-fired facilities. These changes have resulted in coal-fired unit and facility retirements and switching of fuels. The lower cost of natural gas and technological advances in solar and wind power have had a depressive effect on both coal-fired and nuclear-powered generation. (This proposal, if finalized, would have no effect on the nuclear-powered sector, except as it might affect relative prices through its impacts on coal-fired generation.) In the coal-fired sector, the market forces are manifest as scaling back coal-fired power generation (including unit and facility closures) at an accelerated rate. The rate of coal capacity retirement is affected by regulation affecting coal-fired electricity generation as there have been regulations adopted, particularly in the last decade (e.g.,

[8] The data presented in the general description continues to rely on some 2009 conditions, as the industry survey remains the EPA's best available source of information for characterizing operations across the industry.

CCR, CPP and 2015 Steam Electric ELG), that are cited by some power companies when they announce unit or facility closures, fuel switching, or other operational changes. Among some utilities, there is also a general trend of supplementing or replacing traditional generation with alternative sources. As these changes happen in the industry, the electric power infrastructure adjusts and generally trends toward the optimal infrastructure and operations that deliver the country's power demand, with negative effects for some communities and positive effects for others. The negative distributional effects can be particularly difficult for communities affected by company decisions to scale back or retire a facility. Also *see* Section 2.3 of the RIA.

C. Control and Treatment Technologies

In general, control and treatment technologies for some wastestreams have continued to advance since the 2015 rule. Often, these advancements provide facilities with additional ways of meeting effluent limitations, in some instances at a lower cost. For this proposal, the EPA incorporated updated information and evaluated several technologies available to control and treat FGD wastewater and BA transport water produced by the steam electric power generating industry. *See* Section VIII of this preamble for details on updated cost information.

1. FGD Wastewater

FGD scrubber systems, either dry or wet, are used to remove sulfur dioxide from flue gas so that sulfur dioxide is not emitted into the air. Dry FGD systems generally do not discharge wastewater, as the water they use is evaporated during operation; wet FGD systems do produce a wastewater stream.

As part of this proposed rule, the EPA is including two additional FGD wastewater treatment technologies among the suite of regulatory options that were not evaluated as main regulatory options in the 2015 rule: Low Hydraulic Residence Time Biological Reduction (LRTR) and membrane filtration, which are further described below.

- 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.

- Membrane Filtration. A membrane filtration system designed specifically for high TDS and TSS wastestreams. These systems are designed to eliminate fouling and scaling associated with industrial wastewater. These systems typically combine pretreatment for potential scaling agents such as calcium, magnesium, and sulfates, and one or more types of membrane technology (e.g., nanofiltration, or reverse osmosis) to remove a broad array of particulate and dissolved pollutants from FGD wastewater. The membrane filtration units may also employ advanced techniques, such as vibration or creation of vortexes to mitigate fouling or scaling of the membrane surfaces.

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:

- Chemical precipitation systems that use tanks to treat FGD wastewater. Chemicals are added to help remove suspended solids and dissolved solids, particularly metals. The precipitated solids are then removed from solution by coagulation/flocculation, followed by clarification and/or filtration. The 2015 rule focused on a specific design that employs hydroxide precipitation, sulfide precipitation (organosulfide), and iron coprecipitation to remove suspended solids and to convert soluble metal ions to insoluble metal hydroxides or sulfides.

- Biological treatment systems that use microorganisms to treat FGD wastewater. The EPA identified three types of biological treatment systems used to treat FGD wastewater: (1) anoxic/anaerobic fixed-film bioreactors, which target removals of nitrogen compounds and selenium, as well as other metals; (2) anoxic/anaerobic suspended growth systems, which target removals of selenium and other metals; and (3) aerobic/anaerobic sequencing batch reactors, which target removals of organics and nutrients. The 2015 rule focused on a specific design of anoxic/anaerobic fixed-film bioreactors that employs a relatively long residence time for the microbial processes. The bioreactor design used as the basis for the 2015 rule, with typical hydraulic residence time on the order of approximately 10 to 16 hours, is referred to in this rulemaking as high residence time reduction (HRTR). The BAT technology basis for the 2015 rule also included chemical precipitation as a pretreatment stage prior to the bioreactor and a sand filter as a polishing step following the bioreactor (i.e., CP+HRTR).

- Thermal evaporation systems that use a falling-film evaporator (or brine concentrator), following a softening pretreatment step, to produce a concentrated wastewater stream and a distillate stream to reduce the volume of wastewater by 80 to 90 percent and also reduce the discharge of pollutants. The concentrated wastewater is usually further processed in a crystallizer that produces a solid residue for landfill disposal and additional distillate that can be reused within the facility or discharged. These systems are designed to remove the broad spectrum of pollutants present in FGD wastewater to very low effluent concentrations.

- Constructed wetland systems using natural biological processes involving wetland vegetation, soils, and microbial activity to reduce the concentrations of metals, nutrients, and TSS in wastewater. High temperature, chemical oxygen demand (COD), nitrates, sulfates, boron, and chlorides in the wastewater can adversely affect constructed wetlands' performance. To avoid this, facilities typically find it necessary to dilute the FGD wastewater with service water before it enters the wetland.

- Some facilities operate their wet FGD systems using approaches that eliminate the discharge of FGD wastewater. These facilities use a variety of operating and management practices to achieve this.

  - Complete recycle. Facilities that operate in this manner do not produce a saleable solid product from the FGD system (e.g., wallboard-grade gypsum). Because the facilities are not selling the FGD gypsum, they are able to allow the landfilled material to contain elevated levels of chlorides, and as a result do not need a separate wastewater purge stream.

  - 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.

  - Fly ash (FA) conditioning. Many facilities that operate dry FA handling systems will add water to the FA to suppress dust or improve handling and/or compaction characteristics in an on-site landfill. The EPA is not aware of any plants using FGD wastewater to condition ash that will be marketed.

  - Combination of wet and dry FGD systems. The dry FGD process involves atomizing and injecting wet lime slurry, which ranges from approximately 18 to 25 percent solids, into a spray dryer. The water in the slurry evaporates from the heat of the flue gas within the system, leaving a dry residue that is removed from the flue gas by a fabric filter (i.e., a baghouse) or electrostatic precipitator (ESP).

- Underground injection. These systems dispose of wastes by injecting them into an underground well as an alternative to discharging wastewater to surface waters.

The EPA also collected new information on other FGD wastewater treatment technologies, including spray dryer evaporators, direct contact thermal evaporators, zero valent iron treatment, forward osmosis, absorption or adsorption media, ion exchange, electrocoagulation, and electrodialysis reversal. These treatment technologies have been evaluated at fullscale or pilotscale, or are being developed to treat FGD wastewater. *See* Section 4.1 of the Supplemental TDD for more information on these technologies.

2. BA Transport Water

BA consists of heavier ash particles that are not entrained in the flue gas and fall to the bottom of the furnace. In most furnaces, the hot BA is quenched in a water-filled hopper.[9] Many facilities use water to transport (sluice) the BA from the hopper to an impoundment system or a dewatering bin system. In both the impoundment and dewatering bin systems, the BA transport water is usually discharged to surface water as overflow from the system, after the BA has settled to the bottom. In addition to wet sluicing to an impoundment or dewatering bin system, the industry also uses the following BA handling systems that generate BA transport water:

- Remote Mechanical Drag System. These systems use the same processes as wet-sluicing impoundment or dewatering bin systems to transport bottom ash to a remote mechanical drag system. A drag chain conveyor dewaters the bottom ash by pulling it out of the water bath on an incline. The system can either be operated as a closed-loop (evaluated during the 2015 rule) or a high recycle rate system. For this proposed rule, under the high recycle rate option, facilities would be permitted to purge a portion of the wastewater from the system to maintain a high recycle rate, as described in Section VII of this preamble.[10]

---

[9] Consistent with the 2015 rule, boiler slag is considered BA.

[10] In some cases, additional treatment may be necessary to maintain a closed-loop system. This additional treatment could include polymer addition to enhance removal of suspended solids, or membrane filtration of a slip stream to remove dissolved solids.

- Dense Slurry System. These systems use a dry vacuum or pressure system to convey the bottom ash to a silo (as described below for the "Dry Vacuum or Pressure System"), but instead of using trucks to transport the bottom ash to a landfill, the facility mixes the bottom ash with water (a lower percentage of water compared to a wet-sluicing system) and pumps the mixture to the landfill.

As part of the 2015 rule and this reconsideration, the EPA identified the following BA handling systems that do not generate bottom ash transport water.

- Mechanical Drag System. These systems are located directly underneath the boiler. The bottom ash is collected in a water quench bath. A drag chain conveyor dewaters the bottom ash by pulling it out of the water bath on an incline.

- Dry Mechanical Conveyor. These systems are located directly underneath the boiler. The system uses ambient air to cool the bottom ash in the boiler and then transports the ash out of the boiler on a conveyor. No water is used in this process.

- Dry Vacuum or Pressure System. These systems transport bottom ash from the boiler to a dry hopper without using any water. Air is percolated through the ash to cool it and combust unburned carbon. Cooled ash then drops to a crusher and is conveyed via vacuum or pressure to an intermediate storage destination.

- Vibratory Belt System. These systems deposit bottom ash into a vibratory conveyor trough, where the ash is air-cooled and ultimately moved through the conveyor deck to an intermediate storage destination without using any water.

- Submerged Grind Conveyor. These systems are located directly underneath the boiler and are designed to reuse slag tanks, ash gates, clinker grinders, and transfer enclosures from the existing wet sluicing systems. The system collects bottom ash from the discharge of each clinker grinder. A series of submerged drag chain conveyors transport and dewater the bottom ash.

See Section 4.2 of the Supplemental TDD for more information on these technologies.

VI. Data Collection Since the 2015 rule

A. Information from the Electric Utility Industry

1. Engineering Site Visits

During October and November 2017, the EPA conducted seven site visits to facilities in five states. The EPA selected facilities to visit using information gathered in support of the 2015 rule, information from industry outreach, and publicly available facility-specific information.

The EPA visited four facilities that were previously visited in support of the 2015 rule because they had recently conducted, or were currently conducting, FGD wastewater treatment pilot studies. The EPA also revisited facilities that had implemented new FGD wastewater treatment technologies or BA handling systems (after the 2015 rule) to learn more about implementation timing, start-up and operation, and implementation costs.

The specific objectives of these site visits were to gather general information about each facility's operations; their pollution prevention and wastewater treatment system operations; their ongoing pilot or laboratory scale studies for FGD wastewater treatment; and BA handling system conversions.

2. Data Requests, Responses, and Meetings

Under the authority of Section 308 of the Clean Water Act (CWA) (33 U.S.C. 1318), in January 2018, the EPA requested the following information from nine steam electric power companies that own coal-fired facilities generating FGD wastewater:

- FGD wastewater characterization data associated with testing and implementation of treatment technologies, in 2013 or later.
- Information on halogen usage to reduce flue gas emissions, as well as halogen concentration data in FGD wastewater.
- Projected installations of FGD wastewater treatment technologies.
- Cost information for projected or installed FGD wastewater treatment systems, from bids received in 2013 or later.

After receiving each company's response, the EPA met with these companies to discuss the FGD-related data submitted, other FGD and BA data outside the scope of the request that the company believed to be relevant, and suggestions each company had for potential changes to the 2015 rule with respect to FGD wastewater and BA transport water. The EPA used this information to learn more about the performance of treatment systems, inform the development of FGD wastewater limitations, learn more about facility-specific halogen usage (such as bromide), and obtain information useful for updating cost estimates of installing candidate treatment technologies. As needed, the EPA conducted follow-up meetings and conference calls with industry representatives to discuss and clarify these data.

3. Voluntary BA Transport Water Sampling

In December 2017, the EPA invited seven steam electric facilities to participate in a voluntary BA transport water sampling program designed to obtain data to supplement the wastewater characterization data set for BA transport water included in the record for the 2015 rule. The EPA asked facilities to provide analytical data for ash pond effluent and untreated BA transport water (i.e., ash pond influent). The EPA selected the facilities based on their responses to its 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines (*see* Section 3.2 of the 2015 TDD). Two facilities chose to participate in the voluntary BA sampling program. These data were incorporated into the analytical data set used to estimate pollutant removals for BA transport water.

4. Electric Power Research Institute (EPRI) Voluntary Submission

EPRI conducts studies—funded by the steam electric power generating industry—to evaluate and demonstrate technologies that can potentially remove pollutants from wastestreams or eliminate wastestreams using zero discharge technologies. Following the 2015 rule, the EPA reviewed 35 reports published between 2011 and 2018 that EPRI voluntarily provided regarding characteristics of FGD wastewater and BA transport water, FGD wastewater treatment pilot studies, BA handling practices, halogen addition rates, and the effect of halogen additives on FGD wastewater. The EPA used information presented in these reports to inform the development of numeric effluent limitations for FGD wastewater and to update methods for estimating the costs and pollutant removals associated with candidate treatment technologies.

5. Meetings with Trade Associations

In May and June of 2018, the EPA met with the Edison Electric Institute (EEI), the National Rural Electric Cooperatives Association (NRECA), and the American Public Power Association (APPA). These trade associations represent investor-owned utilities, electric cooperatives, and community-owned utilities, respectively. The EPA also met with the Utility Water Act Group (UWAG), an association comprising the trade associations above as well as individual electric utilities. The EPA met with each of these trade associations separately and together to discuss the technologies and the analyses presented in the 2015 rule and to hear suggestions for potential changes to the 2015 rule. The EPA also used information from these meetings to update industry profile data (i.e., accounting for retirements, fuel conversions, and updated treatment technology installations).

B. Information from the Drinking Water Utility Industry and States

The EPA obtained additional information from the drinking water utility sector and states on the effects of bromide discharges from steam electric facilities on drinking water treatment processes. First, the EPA received letters from, and met with, the American Water Works Association (AWWA), the Association of Metropolitan Water Agencies (AMWA), the National Association of Water Companies (NAWC), the Association of Clean Water Administrators (ACWA), and the Association of State Drinking Water Administrators (ASDWA). Second, the EPA visited two drinking water treatment facilities in North Carolina that have modified their treatment processes to address an increase in disinfection byproduct levels due to bromide discharges from an upstream steam electric power facility. Finally, the EPA obtained data on surface water bromide concentrations and data from drinking water monitoring from the two drinking water treatment facilities. The EPA also obtained existing state data from other drinking water treatment facilities from the states of North Carolina and Virginia.

C. Information from Technology Vendors and Engineering, Procurement, and Construction (EPC) Firms

The EPA gathered data on availability and effectiveness from technology vendors and EPC firms through presentations, conferences, meetings, and email and phone contacts regarding FGD wastewater and BA handling technologies used in the industry. The data collected informed the development of the technology costs and pollutant removal estimates for FGD wastewater and BA transport water. The EPC firms also suggested potential changes to the 2015 rule.

D. Other Data Sources

The EPA gathered information on steam electric generating facilities from the Department of Energy's (DOE's) Energy Information Administration (EIA) Forms EIA-860 (Annual Electric Generator Report) and EIA-923 (Power Plant Operations Report). The EPA used the 2015 through 2017 data to update the industry profile prepared for the 2015 rule, including commissioning dates, energy sources, capacity, net generation, operating statuses, planned retirement dates, ownership, and pollution controls of the boilers.

The EPA conducted literature and Internet searches to gather information on FGD wastewater treatment technologies, including information on pilot studies, applications in the steam electric power generating industry, and implementation costs and timelines. The EPA also used the Internet searches to identify or confirm reports of planned facility and boiler retirements, and reports of planned unit conversions to dry or closed-loop recycle ash handling systems. The EPA used this information to inform the industry profile and identify process modifications occurring in the industry.

The EPA received information from several environmental groups and other stakeholders following the 2015 rule. In general, these groups voiced concerns about extending the period that facilities could continue to discharge FGD wastewater and BA transport water pollutants subject to BPT limitations, as well as steam electric bromide discharges, their interaction with drinking water treatment facilities, and the associated human health effects. They also noted the improved availability of technological controls for reducing or eliminating pollutant discharges from FGD and BA handling systems. Finally, they provided examples where they believed that states had not properly considered the "as soon as possible date" for the new, more stringent BAT requirements in the 2015 rule when issuing permits.

VII. Proposed Regulation

A. Description of the BAT/PSES Options

The proposal evaluates four regulatory options and identifies one proposed option, as shown in Table VII-1. All options include similar technology bases for BA transport water, except that Option 2 allows surface impoundments and a BMP plan for low utilization boilers. In general, each successive option from Option 1 to 4 would achieve a greater reduction in FGD wastewater pollutant discharges. Each subcategorization is described further in Section VII.C below. In addition to some specific requests for comment included throughout this proposal, the EPA solicits comment on all aspects of this proposal, including the information, data and assumptions EPA relied upon to develop the proposed regulatory options, as well as the proposed BAT, effluent limitations, and alternate approaches included in this proposal.

TABLE VII-1. Main Regulatory Options

Wastestream	Subcategory	Technology basis for the BAT/PSES regulatory Options			
		1	2	3	4
FGD Wastewater	N/A	Chemical precipitation	Chemical precipitation + low hydraulic residence time biological treatment	Chemical precipitation + low hydraulic residence time biological treatment	Membrane filtration
	High FGD flow facilities	NS	Chemical precipitation	Chemical precipitation	Chemical precipitation
	Low utilization boilers	NS	Chemical precipitation	NS	NS
	Boilers retiring by 2028	Surface impoundments	Surface impoundments	Surface impoundments	Surface impoundments
FGD Wastewater Voluntary Incentives Program (Direct Dischargers Only)		Membrane filtration	Membrane filtration	Membrane filtration	N/A
BA Transport Water	N/A	Dry handling or High recycle rate systems	Dry handling or High recycle rate systems	Dry handling or High recycle rate systems	Dry handling or High recycle rate systems
	Low utilization boilers	NS	Surface impoundments +BMP plan	NS	NS
	Boilers retiring by 2028	Surface impoundments	Surface impoundments	Surface impoundments	Surface impoundments

NS = Not Subcategorized

Note: The table above does not present existing subcategories included in the 2015 rule as the EPA is not proposing any changes to the existing subcategorization of oil-fired units or units with a nameplate capacity of 50 MW or less.

1. FGD Wastewater

Under Option 1, the EPA would establish BAT limitations and PSES for mercury and arsenic based on chemical precipitation. For Options 2 and 3, the EPA would establish BAT limitations and PSES for mercury, arsenic, selenium, and nitrate/nitrate based on chemical precipitation followed by LRTR and ultrafiltration. Option 2 subcategorizes boilers producing less than 876,000 MWh per year[11] and for those boilers would require mercury and arsenic

[11] The equivalent of a 100 MW boiler operating at 100% capacity or a 400 MW boiler operating at 25% capacity.

limitations and pretreatment standards based on chemical precipitation.[12] Finally, for Option 4, the EPA would establish BAT limitations and PSES for mercury, arsenic, selenium, nitrate-nitrite, bromide, and TDS based on membrane filtration. Options 2, 3, and 4 would subcategorize facilities with high FGD flows, and for this subcategory would establish limitations and standards for mercury and arsenic based on chemical precipitation. 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. Finally, the EPA would establish voluntary incentives program limitations for mercury, arsenic, selenium, nitrate-nitrite, bromide, and TDS based on membranes.

2. BA Transport Water

Under all options described above, the EPA proposes to control discharge of pollutants from BA transport water by establishing daily BAT limitations and PSES on the volume of BA transport water that can be discharged based on high recycle rate systems. A high recycle rate system is a recirculating wet ash handling system operated such that it periodically discharges (purges) a small portion of the process wastewater from the system. Under all 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 gravity settling in surface impoundments. Under Option 2, for boilers producing less than 876,000 MWh per year, BAT effluent limitations for BA transport water would be set equal to the BPT effluent limitations based on gravity settling in surface impoundments to remove TSS.[13] Such facilities would also

[12] As explained above, EPA is not proposing to revise BAT limitations or PSES for oil-fired boilers and/or small boilers (50 MW or smaller).

[13] Although TSS is a conventional pollutant, as it did in the 2015 rule, whenever EPA would be regulating TSS in any final rule following this proposal, it would be regulating it as an indicator pollutant for the particulate form of toxic metals.

be required to develop and implement a BMP plan to minimize the discharge of pollutants from BA transport water. Because POTWs are designed to treat conventional pollutants such as TSS, TSS is not considered to pass through and EPA would establish PSES based on the inclusion of a BMP plan only. For additional information on pass through analysis, *see* Section VII(C) of the 2015 rule preamble. Finally, the EPA proposes a slight modification of the definition of BA transport water to exclude water remaining in a tank-based high recycle rate system at the end of the useful life of the facility.[14] The EPA proposes not to characterize a technology basis for BAT/PSES applicable to such wastewater at this time.[15]

B. Rationale for the Proposed BAT

In light of the criteria and factors specified in CWA sections 304(b)(2)(B) and 301(b)(2)(A) (*see* Section IV of this preamble), the EPA proposes to establish BAT effluent limitations based on the technologies described in Option 2.

1. FGD Wastewater

This proposal identifies treatment using chemical precipitation followed by a low hydraulic residence time biological treatment including ultrafiltration as the BAT technology basis for control of pollutants discharged in FGD wastewater because after considering the factors specified in CWA section 304(b)(2)(B), the EPA proposes to find that this technology is available and economically achievable. More specifically, the technology basis for BAT would

[14] Under this modified definition, the water at the end of the useful life of the facility would be at most the volume of a full system. Since the high recycle rate system being selected as BAT allows for a 10 percent purge of the system volume each day, this would be the equivalent of 10 days discharge, a marginal, one-time increase in pollution.

[15] As illustrated above, there is a wide range of technologies currently in use for pollutant discharges associated with BA transport water, and new approaches continue to emerge. For the exclusion proposed today, permitting authorities would establish BAT limitations for such discharges on a site-specific, best professional judgement (BPJ) basis. 33 U.S.C. 1342 (a)(1)(B); 40 CFR 124.3. Pretreatment program control authorities would need to develop local limitations to address the introduction of pollutants from this wastewater to POTWs that cause pass through or interference, as specified in 40 CFR 403.5(c)(2).

include the same chemical precipitation system described in the 2015 rule. Thus, it would employ equalization, hydroxide and sulfide (organosulfide) precipitation, iron coprecipitation, and removal of suspended and precipitated solids. This chemical precipitation system would be followed by a low hydraulic residence time, anoxic/anaerobic biological treatment system designed to remove heavy metals, selenium, and nitrate-nitrite.[16] The LRTR bioreactor stage would be followed by an ultrafilter to remove suspended solids exiting the bioreactor, including colloidal particles.

Both chemical precipitation and biological treatment are well-demonstrated technologies that are available to steam electric facilities for use in treating FGD wastewater. In addition to the 39 facilities mentioned as using chemical precipitation in the 2015 rule preamble, facilities have installed, or begun installation of such systems, because they have taken steps to cease using surface impoundments to treat their FGD wastewater. In addition, chemical precipitation has been used at thousands of industrial facilities nationwide for the last several decades as described in the 2015 rule record. Ultrafilters downstream of the biological treatment stage are designed for the removal of suspended solids exiting the bioreactor, such as any reduced, insoluble selenium, mercury, and other particulates. Ultrafiltration uses a membrane with pore size small enough to remove these smaller suspended particulates after the biological treatment stage, but still much larger than the pore size of the membrane technology (i.e., nanofiltration or reverse osmosis) that is the basis for option 4 and the VIP which is designed to remove dissolved metals and inorganics (e.g., nutrients, bromides, etc.). Unlike the nanofiltration and reverse

---

[16] Similar to the 2015 rule and consistent with discussions with engineering firms and facility staff, EPA assumed that in order to meet the limitations and standards, 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), where the FGD system metallurgy can accommodate an increase in chlorides. *See* Section 5 of the Supplemental TDD.

osmosis technologies, ultrafilters do not generate a brine that would require encapsulation with fly ash or other disposal techniques. 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 treatment technology and do not result in the same non-water quality environmental impacts that are associated with the brine generated by the membrane technology of Option 4 and proposed for the VIP program.

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] Of these fifteen facilities, nine are currently operating anoxic/anaerobic biological treatment designed to substantially reduce nitrogen compounds and selenium in their FGD wastewater. These biological treatment systems are a mix of low and high hydraulic residence time.[18] The EPA identified a tenth facility that previously operated an anoxic/anaerobic biological treatment system; however, more recently installed a thermal system for the treatment of FGD wastewater. Another five steam electric facilities are also operating thermal treatment systems for FGD wastewater.

---

[17] These fifteen facilities represent 11 percent of steam electric facilities with wet scrubbers. 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.

[18] In addition to these nine facilities, some facilities employ other types of biological treatment. Some of these systems are sequencing batch reactors (SBR), which treat nitrogen, and that technology can be operated to remove selenium. The SBR systems currently operating at power facilities, however, would likely not be able to meet the limitations discussed in today's proposal without reconfiguration.

In the 2015 rule, the EPA rejected three availability arguments made against biological treatment generally. The EPA is not proposing to change these findings based on record information received since the 2015 rule but solicits comment on whether, and to what extent, these findings should be retained for the final rule. First, the EPA rejected the argument that maintaining a biological system over the long run was infeasible. Of the ten full-scale systems discussed above, four facilities have used the biological technology to treat FGD wastewater for more than a decade under varying operating conditions, climate conditions, and coal sources. Many pilot tests of the biological technology have been conducted at various facilities, and data from these tests demonstrate that even in the face of major upsets within the chemical precipitation stage of treatment, the biological stage continues to reduce selenium and nitrogen.

In the 2015 rule, the EPA also rejected the argument that selenium removal efficacy was subject to the type of coal burned (specifically subbituminous coal) and coal-switching. Facilities have continued to operate biological treatment systems while switching coals and, in those cases, have maintained a consistent level of selenium removal. Furthermore, at least three pilot and two full-scale systems have now been successfully run or installed to treat FGD wastewater at facilities burning sub-bituminous coals or blends of bituminous and sub-bituminous coals, encompassing both HRTR and LRTR technologies.

Finally, in the 2015 rule the EPA rejected arguments that cycling of facilities up and down in production, and even out of service for various periods of time, would affect the ability of facilities to meet the effluent limitations. Industry provided data for two facilities showing that they successfully operated biological systems while cycling operations and undergoing shutdowns in the years since the 2015 rule.

While the rationale above applies to both HRTR and LRTR technologies, the EPA proposes to establish BAT based on the LRTR technologies. LRTR reductions are comparable to HRTR reductions[19], are less costly, and require significantly less process or facility footprint modifications than the HRTR option. 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.[20]

LRTR is less costly than HRTR. Compared to the baseline of the 2015 rule, LRTR is estimated to save approximately $72 million per year in after-tax costs to industry.

LRTR requires fewer process changes than HRTR. Compared to HRTR, LRTR installations are less complex and require fewer modifications to a facility's footprint. The HRTR systems selected in the 2015 rule were large, concrete tanks which, along with their associated piping and pumping and control equipment, would be fabricated on site. By contrast, new LRTR systems have smaller footprints, and in many cases come prefabricated as modular components, including the ultrafilter polishing stage, requiring little more than a concrete foundation, electricity supply, and piping connections.

The EPA is not proposing to establish BAT limitations or PSES based on chemical precipitation alone (Option 1). As the EPA noted during the development of the 2015 rule,

---

[19] For example, 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.

[20] Courts have recognized that while Section 301 of the CWA is intended to help achieve the national goal of eliminating the discharge of all pollutants, at some point the technology-based approach has its limitations. *See* 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 polluting agents from our nation's waters […]").

chemical precipitation is effective at removing mercury, arsenic, and certain other heavy metals. While basing BAT limitations and PSES on this technology alone could save industry $103 million per year in after-tax costs relative to the 2015 rule, this technology alone does not remove nitrogen, nor does it remove the majority of selenium. Furthermore, the data in the EPA's record demonstrate that both LRTR and HRTR remove approximately 90 percent of the mercury remaining in the effluent from chemical precipitation treatment.[21] Because the combination of chemical precipitation with LRTR provides substantial further reductions in the discharge of pollutants, the EPA proposes chemical precipitation followed by LRTR for BAT.

The EPA is not proposing to establish BAT limitations based on membrane filtration (Option 4). Based on the EPA's record, the EPA could not conclude that membrane filtration is technologically available nationwide at this time, as the term is used in the CWA, but may become "available" on a nationwide basis by 2028 (this is reflected in the date of compliance for the VIP program under Options 2 and 3). Furthermore, membrane filtration entails non-water-quality environmental impacts (associated with management of the brine) that the EPA proposes to find unacceptable.

At the time of the 2015 rule, the EPA had no record of information about membrane filtration technologies being used to treat FGD wastewater. Since that time, the EPA collected information on several types of membrane filtration technologies. Microfiltration and ultrafiltration membranes are used primarily for removing suspended solids, including colloids. Nanofiltration, reverse osmosis, forward osmosis, and electrodialysis reversal (EDR) membranes are used to remove a broad range of dissolved pollutants. Each of these membrane filtration

[21] Recall that the 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.

technologies generate both a treated effluent and a residual requiring further treatment or disposal. Microfiltration and ultrafiltration generate a solid waste residual which is disposed. Similarly, nanofiltration, reverse osmosis, forward osmosis, and EDR all produce a concentrated brine residual which must be disposed.

The EPA's current record includes information on seven pilot studies of FGD wastewater treatment at domestic facilities using four different membrane filtration technologies.[22] All of these technologies first employed some form of suspended solids removal such as microfiltration or chemical precipitation. This pretreated FGD wastewater was then fed into either nanofiltration or reverse osmosis membrane filtration systems.[23] For several of the pilot studies, the resultant brines were mixed with FA and/or lime to test the potential for encapsulation of the concentrated brine wastestream.[24]

The EPA 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, although EPA is aware of three facilities in China which have installed such membrane filtration systems.[25] The record contains limited information about these facilities. Two of the facilities employ pretreatment and a combination of reverse osmosis and forward osmosis. The EPA does not have detailed information about the specific configurations or the long-term performance of these two systems, nor is the EPA aware of how the resultant brine is

[22] Two of these pilot studies were completed in 2014, but information about these tests was not provided to EPA prior to the 2015 rule.

[23] The EPA has also learned of an eighth pilot on an EDR system, but no data have yet been provided (*https://www.filtsep.com/water-and-wastewater/news/saltworks-completes-fgd-pilot-in-us/*).

[24] The record includes additional encapsulation studies and data not explicitly linked to these seven pilots.

[25] Ultrafiltration has been installed as part of FGD wastewater treatment systems in the U.S.; however, these membranes are intended to remove suspended solids, not dissolved pollutants.

being disposed.[26] Furthermore, the company that sold these two systems has since ceased commercial operations.[27] The third facility operating in China employs pretreatment followed by nanofiltration and reverse osmosis. At this facility, the brine is crystallized and the resulting salt is sold for industrial uses. The EPA does not have information on the long-term performance of this system.

While the EPA does have some information about the use of membrane filtration on FGD wastewater from pilot studies, uncertainty remains regarding operation of the suite of membrane filtration technologies evaluated by the EPA as the basis for Option 4. With respect to data from the pilot studies, these studies focused on membrane technologies that would remove dissolved pollutants. For the technologies designed to remove dissolved pollutants, several studies either did not include a second stage of membrane filtration (i.e., a reverse osmosis polishing stage which electric utilities and vendors indicated would need to be part of any potential future membrane filtration system they would install and operate with a discharge) or provided only summaries of effluent data because of nondisclosure agreements between EPRI, treatment technology vendors, and/or the plant operators. In both cases, this prevented the EPA from fully analyzing the pollutant removal efficacy and effluent variability associated with the treatment systems used in those studies. The pilot tests that omitted the second stage of membrane filtration do not provide sufficient insight into the performance capabilities of the membrane technology because the initial membrane filtration step (e.g., a nanofilter unit) does not by itself remove the broad range of pollutants as effectively as would be achieved by the two-stage configuration.

[26] This is in contrast to biological treatment systems for which EPA has long-term performance data. Although LRTR and HRTR systems differ in their configuration (e.g., residence time), the underlying performance has been well demonstrated on this wastewater.

[27] The following story summarizes the forward osmosis company Oasys ceasing commercial operations: *https://www.bluetechresearch.com/news-blog/comment-oasys-hits-funding-drought/*

The pilot tests for which the EPA has only summary-level data provide summary statistics, such as the observed range of pollutant concentrations, average influent and effluent pollutant concentrations, and duration of the testing periods. However, the EPA lacks the individual daily sample results that are needed to fully evaluate treatment system operation and calculate effluent limitations. Complete data sets were only available from three pilot facilities using a single vendor's reverse osmosis technology.[28]

In addition, while the EPA does have information about membrane filtration application to FGD wastewater from bids and engineering documents, those sources express concerns about operating a technology on this wastewater that would be the first of its kind in the U.S. With respect to information from bids for full-scale installations and related documents, the EPA obtained copies of bids that represented a single vendor's reverse osmosis-based technology and that incorporated performance guarantees. Such guarantees, which are standard within the steam electric power generating industry, act to transfer the costs of specific performance issues from the purchaser of the equipment to the vendor. While the willingness of this vendor to take on these risks might suggest confidence in the long-term performance of its technology, third-party EPC firms with no vested interest in the 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. This further supports EPA's proposal to

[28] These three data sets served as the basis of the proposed revisions to the VIP limitations, described further in Section XIII of this preamble. These limited data sets do not provide sufficient information to evaluate the performance of nanofiltration and reverse osmosis membrane filtration technology as the primary treatment for dissolved pollutants FGD wastewater. The EPA anticipates that additional pilots, tests and data collection could result in these technologies becoming available by the VIP compliance date of 2028. By contrast and for the reasons explained in section VII.2.B., the EPA proposes to conclude that ultrafiltration technology is available for use in the polishing stage for systems using LRTR biological systems as the primary treatment technology for FGD wastewater

find, at this time, that membrane filtration is not, technologically available or an appropriate basis for mandatory requirements for the entire industry. The EPA solicits comment on this availability finding, and whether membrane filtration may become nationally available sooner or later than 2028.

The EPA also rejects membranes as the technology basis for BAT for all existing facilities because it could discourage more valuable forms of beneficial reuse of FA (such as replacing Portland cement in concrete) potentially causing more FA to be incorporated in wastes being disposed.[29] While there are several alternative ways to treat or dispose of the brine generated by membrane filtration, the method most likely to be employed (based on bids, engineering documents, and discussions with electric utilities) is encapsulation with FA and lime for disposal of the resulting solid in a landfill.[30]

Landfilling an encapsulated material raises challenges. For instance, comingling might result in a leachate blowout. The King County Landfill in Virginia experienced a leachate blow out when compact CCR materials with a low infiltration rate were layered with normal municipal solid waste having a higher infiltration rate. Similarly, in the case of encapsulated brine paste, the paste would set and thereafter achieve a very low infiltration rate. When comingled with CCRs having a higher infiltration rate, this would lead to layers with disparate infiltration rates akin to those experienced in the King County scenario. Thus, segregation of low infiltration rate encapsulated brine in a landfill cell separate from other, higher infiltration wastes could be necessary to prevent this layering, and a potential leachate blowout. Such dedicated landfill cells do not exist today, and would require time to permit and construct.

---

[29] While the 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.

[30] Bids also indicate that this would be the least-cost brine management alternative.

Moreover, instead of disposing of their FA, facilities can sell it for beneficial use. As stated in the 2015 CCR rule:

> The beneficial use of CCR is a primary alternative to current disposal methods. And as EPA has repeatedly concluded, it is a method that, when performed correctly, can offer significant environmental benefits, including greenhouse gas (GHG) reduction, energy conservation, reduction in land disposal (along with the corresponding avoidance of potential CCR disposal impacts), and reduction in the need to mine and process virgin materials and the associated environmental impacts.[31]

According to 2016 EIA data, the median percent of FA sold for beneficial use by the facilities with wet FGD systems is approximately fifty percent, with a range of zero to one hundred percent. The fact that encapsulation with FA and lime is the most likely, and least cost, brine management method that facilities could employ nationally, combined with the high percent of FA currently being beneficially used, indicates that selection of membrane filtration as BAT could discourage environmentally preferable beneficial uses of FA, such as replacement of Portland cement in concrete.[32] Specifically, the Agency estimated in U.S. EPA (2011) that each ton of fly ash used as a substitute for Portland cement would avoid 5,400 megajoules of nonrenewable energy use, 690 liters of water use, 1,000,000 grams (g) of CO2 emissions, 840 g of methane emissions, 1,400 g of CO emissions, 2,700 g of NOx emissions, 2,500 g of SOx emissions, 2,400 g of PM, 0.08 g of Hg, 490 g of TSS discharge, 23 g of BOD discharge, and 46 g of COD discharge.[33] After considering these cross-program environmental impacts, the EPA

---

[31] 80 FR 21329 (April 17, 2015).

[32] Although the EPA evaluated FA and lime encapsulation as the least-cost nationally available brine disposal alternative, other alternatives may have higher costs and non-water quality environmental impacts. For example, if a facility chose to crystallize the resulting brine to continue selling its FA, this thermal crystallization process could have a higher cost and parasitic energy load.

[33] U.S. EPA (Environmental Protection Agency). 2011. *Waste and Materials - Flow Benchmark Sector Report: Beneficial Use of Secondary Materials - Coal Combustion Products*. Office of Solid Waste and Emergency Response. Washington, DC. 20460. April.

proposes to find that discouraging this beneficial use of FA would result in unacceptable non-water-quality environmental impacts.

Finally, while the EPA views the foregoing reasoning as sufficient to find that membrane filtration is not BAT for all existing sources, the EPA notes that membrane filtration is projected to cost industry more than the proposed BAT option for FGD wastewater, i.e., chemical precipitation plus LRTR. Added to these costs are the costs to facilities of disposing of the resulting brine. Some facilities that otherwise sell their FA may choose to use their FA to encapsulate the brine, thereby foregoing revenue from FA sales. Other facilities that choose to continue to sell their FA must dispose of the brine using another disposal alternative, such as crystallization, at an additional cost. Costs are a separate statutory factor that the EPA considers in selecting BAT (see, for example, *BP Exploration & Oil, Inc. v. EPA*, 66 F.3d 784, 796 (6th Cir. 1996). Here, while these costs do not make the membrane filtration option economically unachievable, the additional costs associated with membrane filtration provide additional support for the EPA's proposal that membrane filtration is not BAT for all existing sources.

Although the EPA is proposing to reject membranes as the national technology basis for BAT, the EPA proposes to establish a VIP based on membrane technology, as discussed later in this section. The EPA solicits comment on this conclusion. Furthermore, the EPA solicits comment on whether there are early adopters who have already contracted for, purchased, or installed biological technology for compliance with the 2015 rule, and whether these facilities should be included as a subcategory not subject to the final BAT of Option 4, if finalized. The EPA solicits comment on whether such a subcategory could be based on the age of the new pollution control equipment that had not yet lived out its useful life, the disparate costs of purchasing two sets of equipment, or other statutory factors.

As described further below, the EPA is also not proposing to establish BAT limitations based on other technologies also evaluated in the 2015 rule.

First, except for the end of life boiler and low-utilization subcategories discussed below, the EPA is not proposing to establish BAT limitations based on surface impoundments. Surface impoundments are not as effective at controlling pollutants like dissolved metals and nutrients as available and achievable technologies like CP and LRTR. EPA drew a similar conclusion in the 2015 rule, and nothing in the record developed by the Agency since the 2015 rule would change this determination.

Second, the EPA is not proposing to establish BAT limitations based on thermal technologies, such as chemical precipitation (including softening) followed by a falling film evaporator, on the basis of high costs to industry. In the 2015 rule, the EPA rejected this technology as a basis for BAT limitations due to high costs to industry. Since the 2015 rule, the EPA has collected additional information on full-scale installations and pilots of thermal technologies to treat FGD wastewater. The EPA's record includes information about approximately 10 pilot studies conducted in the U.S., providing performance data for five different thermal technologies. In addition, full scale installations are operating at six facilities,[34] and a seventh purchased thermal equipment, but elected not to install it.[35] While new thermal technologies have been pilot tested and used at full-scale since the 2015 rule, and related cost information demonstrates that thermal technologies are less costly than estimated for the 2015 rule, the thermal costs evaluated in the EPA's memorandum *FGD Thermal Evaporation Cost*

[34] One of these facilities successfully ran three different thermal systems to treat its wastewater, transitioning from a falling film evaporator to a direct-contact evaporator that mixes hot gases in a high turbulence evaporation chamber, and finally to a spray dryer evaporator.

[35] This facility purchased a falling film evaporator for the purpose of meeting water quality-based effluent limitations for boron, but then elected to instead pay approximately $1 million per year to send its wastewater to a local POTW.

Methodology (DCN SE07098) are still three to five times higher than any other option presented in Table VIII-1. As authorized by section 304(b) of the CWA, which allows the EPA to consider costs, the Agency is not proposing that thermal technologies are BAT due to the unacceptable costs to industry. Given the high costs associated with the technology, and the fact that the steam electric power generating industry continues to face costs associated with several other rules, in addition to this rule, the EPA is not proposing to establish BAT limitations for FGD wastewater based on evaporation for all steam electric facilities. The EPA solicits comment on this finding, as well as the accuracy of the revised costs estimates.

Furthermore, since membrane filtration technologies included in Option 4 appear to achieve similar pollutant removals for lower costs than thermal, the EPA is proposing to revise the basis for the VIP limitations adopted in the 2015 rule to membrane filtration, instead of thermal technologies, as discussed later in this section.[36] The EPA solicits comment on the extent to which membrane filtration technologies could be used in lieu of, or in combination with, thermal technologies.

Finally, the EPA is not proposing to decline to establish BAT and leave BAT effluent limitations for FGD wastewater to be established by the permitting authority using BPJ. The EPA explained in the 2015 rule why BPJ determinations would not be appropriate for FGD wastewater, particularly given the availability of several other technologies, and nothing in EPA's record would alter its previous conclusion.

2. BA Transport Water

[36] The EPA notes that thermal technologies could continue to be used to meet the voluntary incentives program limitations based on membrane filtration.

This proposal identifies treatment using high recycle rate systems as the BAT technology basis for control of pollutants discharged in BA transport water because, after evaluating the factors specified in CWA section 304(b)(2)(B), the EPA proposes to find that this technology is available and economically achievable. In the 2015 rule, the EPA selected dry BA handling or closed-loop wet ash handling systems as the technology basis for the "zero discharge" BAT requirements for BA transport water. The EPA established zero pollutant discharge limitations based on these technologies and included a limited allowance for pollutant discharges associated with certain maintenance activities.[37]

At the time of the 2015 rule, the EPA estimated that more than 50 percent of facilities already employed dry handling systems or wet sluicing systems designed to operate closed-loop, or had announced plans to switch to such systems in the near future. Based on new information collected since the 2015 rule, that value is now over 75 percent, nearly evenly split between dry and wet systems. However, since the 2015 rule, the EPA's understanding of the types of available dry systems, and the ability of wet systems to achieve complete recycle has changed, as discussed below.

There have been advances in dry BA handling systems since the 2015 rule.[38] For example, in addition to under-boiler mechanical drag chain systems (described in the 2015 rule), pneumatic systems and submerged grinder conveyors are now available and in use at some facilities. Such systems often can be installed at facilities that are constrained from retrofitting a mechanical drag system due to insufficient vertical space under the boiler.

---

[37] *See* 40 CFR Part 423.11(p).

[38] The term "dry handling" is used to refer to ash handling systems that do not use water as the transport medium for conveying ash away from the boiler. Such systems include pneumatic and mechanical processes (some mechanical processes use water to cool the BA or create a water seal between the boiler and ash hoppers, but the water does not act as the transport medium).

With respect to wet BA handling systems, in their petitions for reconsideration and in recent meetings with the EPA, utilities and trade associations informed the EPA that many existing remote wet systems are, in reality, "partially closed" rather than closed-loop, as indicated by the EPA in the 2015 rule. Utilities and trade associations informed the EPA that these systems operate partially closed, rather than closed, due to small discharges associated with additional maintenance and repair activities not accounted for in the 2015 maintenance allowances,[39] water imbalances within the system such as those associated with stormwater,[40] 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 (*See* DCNs SE08179 and SE06963), others require more extensive process changes and associated increased costs or find them difficult to resolve (*See* DCNs SE08188, SE08180, and SE06920).

The EPA agrees that the new information 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. While some facilities currently handle the challenges discussed above by discharging some portion of their BA transport water (as the zero discharge limitations in the 2015 rule are not yet applicable), the record demonstrates that facilities can likely eliminate such discharges with additional process changes and expenditures. Just as the EPA estimated costs of chemical additions in the 2015 rule to manage scaling, companies could add additional treatment

[39] 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.

[40] 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.

chemicals (caustic) to manage acidity or other chemicals to control alkalinity, make use of reverse osmosis filters 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. Industry-wide, the EPA estimates the costs of fully closing the loop to be $43 million per year in after-tax costs, above and beyond the costs of the systems themselves.[41] These additional costs and process changes were not accounted for in the 2015 rule; however, as discussed in Section 5.3 of the Supplemental TDD, in estimating the baseline costs of the BA limitations in the 2015 rule, the EPA now accounts for these costs. The EPA solicits comment on whether these assumptions and costs are appropriate and requests commenters identify and include available data or information to support their recommended approach.

The EPA also recognizes the need for facilities to consider the standards of multiple environmental regulations simultaneously. As discussed in Section IV above, the EPA is separately proposing changes to the CCR rule that, if finalized, would allow facilities to cease receiving waste in unlined surface impoundments by August 2020.[42] The challenges of operating a truly closed-loop system discussed above are compounded when considered in conjunction with the requirements of the CCR rule. Facilities often send various CCR and non-CCR wastestreams, such as coal mill rejects, economizer ash, etc., with BA transport water into their

[41] Utilities and EPC firms have discussed the availability of new dry systems, such as the submerged grinder conveyor or pressure systems, which at some facilities would have costs similar to recirculating wet systems that would require a purge. Because the EPA did not have cost information to determine the subset of facilities for which new dry systems might be least costly, some portion of the costs estimated for this proposal may be based on selecting recirculating wet systems at facilities which could ultimately go dry. Thus, the EPA may overestimate costs or underestimate pollutant removals at the subset of facilities where such a dry system would be selected.

[42] As discussed in Section IV of this preamble, further information about this proposal is available at *http://www.regulations.gov*, Docket EPA-HQ-OLEM-2019-0172.

surface impoundments. According to reports provided to the EPA and conversations with electric utilities, several facilities have already begun the transition away from impoundments, and also use the BA treatment system for some of their non-CCR wastewaters.[43] This reportedly can lead to or exacerbate problems with scaling, corrosion, or plugging of equipment that complicate achievement of a closed-loop system and require additional process changes and expense to address. All of which problems could be avoided by purging the system from time to time, as necessary. While those facilities that have not yet installed a BA transport water technology (less than 25 percent) could potentially employ a dry system, and those facilities with existing wet systems could potentially segregate their BA transport water from their non-CCR wastewaters, short compliance timeframes under the CCR rule may limit the availability of such options.

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 in combination with the CCR rule, and to give facilities flexibilities that will facilitate orderly compliance with the fast-approaching CCR rule deadlines, 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, the technologies on which the zero discharge BAT limitation adopted in the 2015 rule were based. The EPA's proposal is based on its discretion to give particular weight to the CWA Section 304(b) statutory factor of "process changes." Process changes to existing high recycle rate systems that do not currently operate as closed loop, or that will be installed in the near-future, to comply with this rule in conjunction with the CCR rule as discussed above could be more challenging without a further discharge allowance, and in some cases could also result in the prolonged use of unlined surface impoundments.

[43] In some cases, the treatment system predated even the proposed CCR rule.

The EPA considers that the factors discussed above are sufficient to support the Agency's decision not to select closed-loop systems as BAT for BA transport water. The EPA also notes that cost is a statutory factor that it must consider when establishing BAT, and that closed-loop systems cost more than high recycle rate systems for treatment of BA transport water. While the EPA does not find this higher cost to be economically unachievable, the higher cost of closed loop systems is an additional reason for the EPA to not select closed loop systems as BAT for treating BA transport water.

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. This does not mean that the EPA expects all facilities to discharge up to 10 percent on a regular basis, rather this option is designed to provide flexibility if and when needed to address site-specific challenges of operating the recirculating ash system (for more on implementation, *see* Section XIV of this preamble).[44] The EPA also solicits comment on a facility-specific recycle rate alternative to the 10 percent 30-day rolling average option. 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 in

[44] The EPA's pollutant loading analyses provided in Section IX.B of this preamble and described in detail in the BCA Report and Supplemental TDD were based on an assumed 10 percent purge at each affected facility.

Section VII.C.2 below. Under this approach, 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 system, the facility would be authorized to purge a portion of the system volume. The purge volume 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. The EPA solicits comment on whether these two options provide sufficient notice and regulatory certainty for facilities to understand potential obligations under the proposed rule and associated costs. 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.

Under either option discussed above for determining discharge allowances (10 percent 30-day rolling average or site-specific), there may be wastewater from whatever is purged by the high recycle rate system, and plants may wish to discharge this wastewater. 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] Each facility necessarily has different climates and maintenance needs that could make selecting a uniform treatment system more difficult. Second, utilities have stated that discharges of wastewater associated with high rate recycle systems are sent to low volume wastewater treatment systems, which are typically dewatering basins or

[45] 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.

surface impoundments. Many of these systems are in transition as a result of the CCR rule. New wastewater treatment systems installed for low volume wastewater and other wastestreams (which could be used to treat the wastewater purged from a high recycle rate system), as well as the types of wastestreams combined in such systems, are likely to vary across facilities.

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. The EPA assumes permitting authorities will be in a better position than the EPA to examine site-specific climate and maintenance factors for infrequent events. Permitting authorities will also be in a better position than the 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 high recycle rate system associated with the proposed allowance. The EPA also solicits comment on technologies that could serve as the basis for BAT for this discharge and what technologies state permitting authorities may consider as BPJ. 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. The EPA further solicits comment on whether delaying the selection of appropriate treatment technology though the BPJ process masks the true cost of this proposed rule for both the regulated entity and the regulatory agency that must undertake the evaluation and ultimately establish BPJ. The EPA also solicits comment on whether the EPA should constrain BPJ by precluding the consideration of some technologies (e.g., zero discharge) using nationwide application of the statutory factors. The EPA solicits any data, information or methodologies that may be useful in evaluating the potential costs of establishing and complying with as yet undetermined BPJ requirements.

The EPA is not proposing to identify surface impoundments as BAT for BA transport water except for BATW purge water because surface impoundments are not as effective at removing dissolved metals as available and achievable technologies, such as high recycle rate systems. Furthermore, the record since the 2015 rule shows that facilities have continued to convert away from surface impoundments to the types of technologies described above, either voluntarily or due to the CCR rule, and in 2018, the U.S. Court of Appeals for the District of Columbia vacated that portion of the 2015 CCR rule that allowed both unlined and clay-lined surface impoundments to continue operating. *USWAG v. EPA*, No. 15-1219 (DC Cir. 2018). Since very few CCR surface impoundments are composite-lined, the practical effect of this ruling is that the majority of facilities with operating ponds likely will cease sluicing waste to their ponds in the near future. In the 2015 CCR rule, the EPA estimated that it would be less costly for facilities to install under-boiler or remote drag chain systems and send BA to landfills rather than continue to wet sluice BA and replace unlined ponds with composite lined ponds. This supports the suggestion that surface impoundments are not BAT for all facilities. However, the EPA proposes to identify surface impoundments as BAT for two subcategories, as discussed later in this section.

3. Rationale for Voluntary Incentives Program (VIP)

As part of the BAT for existing sources, the 2015 rule established a VIP that provided the certainty of more time (until December 31, 2023 instead of a date determined by the permitting authority that is as soon as possible beginning November 1, 2018) for facilities to implement new

BAT limitations if they adopted additional process changes and controls that achieve limitations on mercury, arsenic, selenium and TDS in FGD wastewater, based on thermal evaporation technology. *See* Section VIII(C)(13) of the 2015 rule preamble for a more complete description of the selection of the thermal technology basis, chemical precipitation (with softening) followed by a falling film evaporator. The EPA expected this additional time, combined with other factors (such as the possibility that a facility's NPDES permit may need more stringent limitations to meet applicable water quality standards), would lead some facilities to choose this option for future implementation by incorporating the VIP limits into their permit during the permit application process. New information in several utilities' internal analyses and contractor reports provided to the EPA since the 2015 rule, as well as meetings with utilities, EPC firms, and vendors indicates that facility decisions to install the more expensive thermal systems were driven by water quality-based effluent limitations imposed by the NPDES permitting authority. Furthermore, such documents and meetings also show that several facilities considered installing membrane filtration technologies under the 2015 rule VIP as well, and thus the EPA evaluated membrane filtration as an alternative basis for VIP.

The EPA proposes to revise the VIP limitations established in the 2015 rule using membrane filtration as the technology basis because it costs less than half the cost of thermal technology and has comparable pollutant removal performance. Membrane filtration achieves pollutant removals comparable to thermal systems in situations where the thermal system would discharge. Engineering documents for some individual facilities evaluated this technology as a zero liquid discharge system which would recycle permeate into the plant. Due to the higher costs of thermal systems compared to chemical precipitation followed by LRTR, the EPA does not expect that any facility would install a new thermal system under the 2015 rule VIP as the least cost technology. As authorized by section 304(b) of the CWA, which allows the EPA to consider costs, the EPA proposes membrane filtration as the technology basis for the VIP BAT limitations, with limitations for mercury, arsenic, selenium, nitrate-nitrite, bromide, and TDS.[46]

Second, as authorized by section 304(b) of the CWA, which allows the EPA to consider process changes and non-water quality environmental impacts, the EPA proposes to revise the compliance date for the VIP limitations to December 31, 2028. That is the date the EPA has determined that the membrane filtration technology will be available nationwide, as that term is used in the CWA, for those facilities who choose to adopt it. This 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. The EPA notes that this is similar to the eight-year period between promulgation of the 2015 rule and the 2023 deadline for the current voluntary incentives program. The EPA proposes to find that forthcoming changes in membrane filtration brine disposal options may significantly reduce the non-water quality environmental impacts associated with encapsulation, discussed in Section VII(b)(i) above. Through discussions with several utilities and EPRI, the EPA learned that a forthcoming paste technology may allow facilities to mix the brine with lower quantities of FA and lime and pump the resulting paste via pipes to an onsite landfill where the paste would self-level prior to setting as an encapsulated material. According to these discussions, such a process may be less costly than existing brine disposal alternatives. This process could also reduce non-water quality environmental impacts by reducing the amount of FA used, decreasing air emissions and fuel use associated with trucking and spreading, and, where FA is already being disposed of, could reduce the volumes and

[46] Note that the 2015 rule did not include limitations for nitrate/nitrite or bromide.

pollutant concentrations in leachate.[47,48] A compliance date of December 31, 2028, would have the advantage of allowing this forthcoming paste technology potentially enough time to become available, allow facilities more time to permit landfill cells for brine encapsulated with FA and lime if needed, and conduct pilot testing, demonstrations, and further analyses to fully understand and incorporate the process changes associated with membrane filtration operation, and understand the long term performance of the technology for treatment of FGD waste.

One remaining challenge identified for this paste technology is developing approaches to manage wastes (e.g., flush water) from periodic cleaning of the paste transportation piping, where such piping is used.[49] As authorized by section 304(b) of the CWA, which allows the EPA to consider the process employed, the EPA is proposing a modification of the definition of FGD wastewater and ash transport water to explicitly exclude water used to clean FGD paste piping so that facilities using paste piping for brine encapsulation and disposal in an on-site landfill can more easily clean residual paste from pipes.

Taken together, the EPA's proposed changes to the VIP would give facilities greater flexibility when choosing a technology, while continuing to achieve pollutant reductions beyond the BAT limitations that are generally applicable to the industry and currently available nationwide. Under Option 2, the EPA estimated that 18 plants (27 percent of plants estimated to

[47] Sniderman, Debbie. 2017. *From Power Plant to Landfill: Encapsulation. Innovative Technology Offers Elegant Solution for Disposing of Multiple Types of Waste*. EPRI Journal. September 19. Available online at: http://eprijournal.com/from-power-plant-to-landfill-encapsulation/

[48] Although the EPA is not establishing BAT for leachate in the current rulemaking, the vacatur and remand of BAT for leachate in *Southwestern Electric Power Co., et al. v. EPA* means that decreasing volumes of leachate and the concentration of pollutants in that leachate might make more technologies available in a future BAT rulemaking.

[49] Utilities described this process as water pushing a ball through the paste piping when not in use, based on cleaning done of concrete pipes at construction sites. While the ball would clean out the majority of the paste, water would still contact incidental amounts of ash and FGD materials, thus potentially subjecting it to regulations for those wastewaters.

incur FGD compliance costs) may opt into the VIP program and under Option 3 the number rises to 23 plants (34 percent of plants estimated to incur FGD compliance costs). The EPA solicits comment on the accuracy of the cost estimates indicating that these plants would opt into the revised VIP program, including data identifying costs that may be potentially excluded from this analysis. Specifically, the EPA solicits data and information on any potential technology limitations, commercial availability, and other limitations that may affect plants' ability to adopt the VIP limits by the proposed VIP compliance date of 2028.

C. Additional Proposed Subcategories

In the 2015 rule, the EPA established subcategories for small boilers (< 50 MW nameplate capacity) and oil-fired units. The EPA subcategorized small boilers due to disproportionate costs when compared to the rest of the industry and subcategorized oil-fired boilers both because they generated substantially fewer pollutants and are generally older[50] (and more susceptible to early retirement). In the 2015 rule, the EPA stated:

> "If these units shut down, EPA is concerned about resulting reductions in the flexibility that grid operators have during peak demand due to less reserve generating capacity to draw upon. But, more importantly, maintaining a diverse fleet of generating units that includes a variety of fuel sources is important to the nation's energy security. Because the supply/delivery network for oil is different from other fuel sources, maintaining the existence of oil-fired generating units helps ensure reliable electric power generation, as commenters confirmed."[51]

[50] Age is a statutory factor for BAT. CWA section 304(b), 233 U.S.C. 1304(b).
[51] 80 FR 67856.

For these subcategorized units, in the 2015 rule the EPA established differentiated limitations based on surface impoundments (i.e, setting BAT equal to BPT limitations for TSS).

As part of this proposal, the EPA is not proposing a change to the 2015 rule subcategorization of small and oil-fired boilers; therefore, these boilers have limitations for TSS. The EPA is incorporating and expanding on its previous analysis of characteristics and possible differences within the industry. The EPA proposes further subcategorization for FGD wastewater and BA transport water for boilers with low utilization and boilers with limited remaining useful life. In addition, for FGD wastewater, the EPA proposes to subcategorize units with high FGD flows. These proposed subcategories are discussed below.

1. Subcategory for Facilities with High FGD Flows

The EPA is proposing to establish a new subcategory for facilities with high FGD flows based on the statutory factor of cost. 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.[52] This variance request relied primarily on two facts. First, TVA stated that Cumberland's FGD wastewater flow volumes are several million gallons per day,[53] 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

[52] 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.

[53] In the FDF variance, TVA cites to a hypothetical maximum flow of 9 MGD; however, based on survey responses and discussions with TVA staff, the company has never approached this flow rate and does not expect to.

industry.[54] 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.[55] 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.

The EPA proposes to subcategorize facilities with FGD purge flows greater than four 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 to avoid placing a disproportionate cost on such facilities.[56] Such a flow reflects the reasonably predictable flow associated with actual and expected FGD operations.

According to TVA's analysis, chemical precipitation plus biological treatment would result in a capital cost of $171 million, and an O&M cost of approximately $20 million per year.[57] The EPA's cost estimates are even higher than TVA's (a $256 million dollar capital cost plus $21 million per year in O&M). These costs are five to six times higher than comparable

[54] Cumberland accounts for approximately one-sixth to one-seventh of all industry FGD wastewater flows.

[55] Reducing the volume purged from the FGD system or recycling FGD wastewater back to the FGD system can be used to reduce the volume of wastewater requiring treatment, and thus reduce the cost of treating the wastes. However, reducing the flow sent to treatment also has the effect of increasing the concentration of chlorides in the wastewater, and FGD system metallurgy can impose constraints on the degree of recycle that is possible.

[56] Although it is theoretically possible that another coal facility could be built, or an FGD system installed, that resulted in flows of this volume, in practice, all FGD systems in the past decade have been built with materials that allow for recycling of the FGD wastewater. While facilities with these characteristics could potentially apply for an FDF variance, the EPA is proposing to subcategorize them instead because it currently has sufficient information to do so and because FDF variances are governed by strict timelines and procedural requirements set forth in 33 U.S.C. 1311(n).

[57] Email to Anna Wildeman. November 13, 2018.

costs at facilities selling similar numbers of MWh per year.[58] Passing these disparately higher costs on to consumers would likely put the facility at a competitive disadvantage with other coal-fired facilities not subject to the same capital and operating costs. As authorized by section 304(b) of the CWA, which allows the EPA to consider costs, the EPA proposes a new subcategory for FGD wastewater based on unacceptable disparate costs. For such facilities, the EPA proposes to establish BAT based on chemical precipitation alone, with effluent limitations for mercury and arsenic.

2. Subcategory for Boilers with Low Utilization

The EPA is proposing to establish a new subcategory for boilers with low utilization based on the statutory factors of cost and non-water quality environmental impacts (including energy requirements). Low natural gas prices and other factors have led to a decline in capacity utilization for the majority of coal-fired boilers. According to EIA 923 data,[59] overall coal-fired production for 2017 decreased by approximately one-third from 2009 levels, with the majority of boilers decreasing utilization, sometimes significantly. 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.[60]

In light of these industry changes, the EPA examined the costs of the proposed BAT limitations and pretreatment standards for FGD wastewater and BA transport water on the basis

[58] This would generally also hold true for the costs of other FGD technology options at comparable facilities.

[59] *https://www.eia.gov/electricity/data/eia923/*

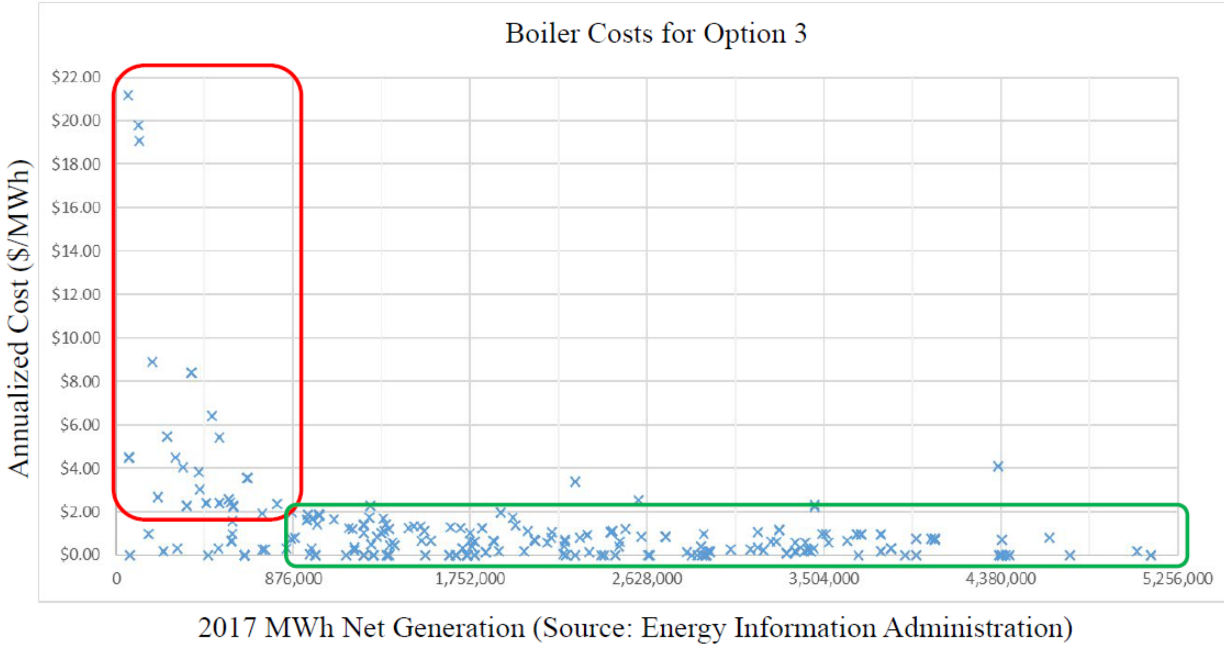
[60] In conversations with electric utilities, several examples were given of former base load facilities which have since modified operations to be load-following, or which no longer produce except for peak days in summer or winter. These discussions tracked closely with changes in production reported in the EIA 923 data.

of MWh produced, rather than the nameplate capacity used to subcategorize boilers less than or equal to 50 MW in the 2015 rule. Due to changed utilization, nameplate capacity has become less representative of electricity production. Nevertheless, the EPA is not proposing any changes to the 50 MW nameplate capacity subcategory of the 2015 rule as that subcategory applied to additional wastestreams not part of this proposal (e.g., fly ash), and has already been implemented in some permits. Thus, the EPA focused on MWh production for boilers greater than 50 MW nameplate capacity, as discussed below.

Similar to the EPA's finding regarding small boilers in the 2015 rule, the record indicates 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. Figure VIII-1 below presents costs per MWh produced as measured against the status quo, rather than against the 2015 rule baseline. As can be seen in this figure, there is a significant difference between boilers above and below 876,000 MWh per year.[61] As a result of these disparate costs, the EPA proposes an additional subcategory for low capacity utilization boilers producing less than 876,000 MWh per year. Many of these boilers are either close to the 50 MW nameplate capacity of the 2015 rule (e.g., a 100 MW boiler running at 100% capacity), or somewhat larger units that have continued to reduce electricity generation due to market forces (e.g., a 400 MW boiler running at 25% capacity). The latter group are expected to produce fewer and fewer MWh per year, moving those boilers further toward the high $/MWh costs over time. Attempting to pass on the higher costs per MWh produced would make these boilers increasingly uncompetitive, exacerbating the disparate cost impacts.

[61] This is the equivalent of a 100 MW boiler running at 100 percent capacity or a 400 MW boiler running at 25 percent capacity.

Figure VIII-1 – Costs per MWh Produced vs. MWh Produced[62]



In addition to disparate costs, the 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.

In light of the information discussed above, the EPA proposes to establish a subcategory for low utilization units producing less than 876,000 MWh per year. 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. The EPA solicits comment on whether chemical precipitation is appropriate and economical or if other approaches would be appropriate. The EPA requests commenters identify and include available data or

---

[62] While the EPA only presents the disparate costs of one technology in this figure, a similar comparison could be made for the technologies comprising Options 1 or 4 for a final rule. No comparison is necessary for Option 2 as that option already incorporates the subcategorization that eliminates these disparate costs.

information to support their recommended approach. Also, for this subcategory, as it did for the subcategories established in the 2015 rule, the EPA proposes to select surface impoundments as the BAT technology basis for BA transport water and establish limitations for TSS based on surface impoundments in combination with a BMP plan under section 304(e) of the Act. Although facilities are likely to meet these TSS limits using technologies other than surface impoundments once they have closed any unlined surface impoundments under the CCR rule, facilities may choose to retrofit a surface impoundment or construct a new surface impoundment. As authorized by section 304(b) of the CWA, which allows the EPA to consider costs, the EPA proposes to find that additional technologies are not BAT for this subcategory due to the unacceptable disproportionate costs per MWh those technologies would impose. Chemical precipitation for FGD wastewater and surface impoundments for BA transport water, along with a requirement to prepare and implement a BMP plan under section 304(e) of the Act to reduce pollutant discharges, are the only technologies the EPA proposes to find would not impose such disproportionate costs on this subcategory of boilers. While the Fifth Circuit in *Southwestern Electric Power Company v. EPA,* 920 F.3d 999, 1018 n.20 (5th Cir. 2019), found EPA's use of surface impoundments as the technology basis for effluent limitations on legacy wastewater to be arbitrary and capricious, 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. Finally, the EPA proposes to find that allowing permitting authorities to set BAT limitations for BA transport water on a case-by-case basis using BPJ for this subcategory would be equally problematic. The technologies a permitting authority would necessarily consider are the same dry handling and high recycle rate systems that result in unacceptable disproportionate costs per MWh, according to the EPA's analysis above. The EPA solicits comment on whether the impacts of the proposed revisions to the CCR rule could result in a different analysis from the disparate costs presented above. The EPA also solicits comment on other options to address the disproportionate impacts identified above.

3. Subcategory for Boilers Retiring by 2028

The EPA is proposing to establish a new subcategory for boilers retiring by 2028 based on 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. The EPA has continued to gather information about facility and boiler retirements, deactivations, and fuel conversions since the 2015 rule. Of the 107 facilities that the EPA identified in Section 3 of the Supplemental TDD that have announced, commenced or completed such actions, the most frequently stated reason was market forces, such as the continued low price of natural gas (49 facilities).[63] This was followed by environmental regulations (33),[64] consent decrees (10), and other reasons (46).[65,66] The fact that environmental regulations were cited by approximately one-third of these facilities and that ELGs were specifically mentioned by some respondents suggests that additional flexibility may help to avoid premature closures for some facilities and/or boilers.

---

[63] This is consistent with recent analyses of the costs of coal-fired electric generation versus other sources. Examples include: (1) *https://www.bloomberg.com/news/articles/2018-03-26/half-of-all-u-s-coal-plants-would-lose-money-without-regulation;*

(2) *https://insideclimatenews.org/news/25032019/coal-energy-costs-analysis-wind-solar-power-cheaper-ohio-valley-southeast-colorado*

[64] Approximately 31 percent of the facilities identified specific environmental regulations affecting the decision-making process. When specific environmental regulations were stated, they included CPP, MATS, ELGs, CCR Rule, and Regional Haze Rules.

[65] Some announcements cited several rationales, hence the numbers do not add to 107.

[66] "Other" includes age, reliability of the facility, emission reductions goals, decreased local electricity demand, facility site limitations, and company goals to invest in clean/renewable energy.

To further explore this, the EPA examined the cost implications of complying with the proposed limitations and standards on a dollar-per-MWh-produced basis under hypothetical boiler retirement scenarios. Cost estimates for this proposal assume that facilities will amortize capital and O&M costs across the 20-year life of the technologies (*see* Section 5 of the Supplemental TDD), so the EPA only examined retirement scenarios within the next 20 years. Furthermore, since O&M costs are already spread out over time, the EPA focused on capital costs, which also tended to make up a sizeable portion of costs in the EPA's estimates. Finally, the EPA looked at both three and seven percent discount rates. The analysis showed that a facility 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 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.

In meetings with the EPA, utilities expressed two other concerns related to retiring units. First, several utilities discussed the 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. Although the utilities indicated that PUCs have historically allowed for cost recovery even after the retirement of a boiler, they provided recent examples of PUCs rejecting cost recovery, which make the prospect of continued recovery after retirement less certain. Second, the utilities expressed the need for sufficient time to plan, construct, and obtain necessary permits and approvals for replacement generating capacity. In discussions of example Integrated Resource Plans (IRPs) and the associated process, utilities suggested timelines that would extend for five to eight years or longer.[67]

[67] Utilities also shared instances of very quick turnaround in some cases.

Finally, the North American Electric Reliability Corporation (NERC) 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.[68] That report found that if these retirements happen faster than the system can respond (*e.g.,* construction of new base load), significant reliability problems could occur. NERC cautions that, though this stress test is not a predictive forecast,[69] the 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.

In light of the information discussed above, and the EPA's authority under section 304(b) to consider cost, the age of equipment and facilities involved, non-water quality environmental impacts (including energy requirements), and other factors that the Administrator deems appropriate, the EPA proposes a new subcategory for boilers with a limited remaining useful life, i.e., those intending to close no later than December 31, 2028, subject to a certification requirement (described in Section XIV). For this subcategory, the EPA proposes to identify surface impoundments as the technology basis for BAT, and establish BAT limitations for TSS for both FGD wastewater and BA transport water. 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. The

---

[68] North American Electric Reliability Corporation (NERC). 2018. *Special Reliability Assessment: Generation Retirement Scenario*. Atlanta, GA 30326. December 18. Available online at: *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf.*

[69] "NERC's stress-test scenario is not a prediction of future generation retirements nor does it evaluate how states, provinces, or market operators are managing this transition. Instead, the scenario constitutes an extreme stress-test to allow for the analysis and understanding of potential future reliability risks that could arise from an unmanaged or poorly managed transition."

EPA proposes to find that additional technologies such as chemical precipitation with or without LRTR for FGD wastewater, and the high recycle rate BA transport water technologies are not BAT for this 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. EPA proposes to find that surface impoundments are the only technology that would not impose such disproportionate costs on this subcategory of boilers. Establishing surface impoundments as BAT for this subcategory would alleviate the choice for these facilities to either pass on disparately high capital costs over a shorter useful life or risk the possibility that post-retirement rate recovery would be denied for the significant capital and operating costs associated with the BAT options in this proposal. Creation of this subcategory would also allow electric utilities to continue the organized phasing out of boilers that are no longer economical, in favor of more efficient, newly constructed generating stations, and would help prevent the scenario described in the NERC stress test. Additionally, 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.[70] The EPA notes that in order to complete closure by 2028, facilities may have to cease receiving waste well in advance of that date; however, 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. Furthermore, the EPA proposes to find that allowing permitting authorities to set BAT limitations for either FGD wastewater or BA transport water on a case-by-case basis using BPJ would be problematic. The technologies a

[70] 40 CFR Part 257.103(b).

permitting authority would necessarily consider are the same systems that result in unacceptable disproportionate costs according to the EPA's analysis (described above). Since these boilers are already nearing the end of their useful life, and are susceptible to early retirement, losing the ability to use surface impoundments for any wastewater prior to currently planned closure dates would undermine the flexibility of the CCR alternative closure provisions and could hasten the retirement of units in a manner more closely resembling the reliability stress test discussed above, which resulted in unacceptable non-water quality environmental impacts (including energy requirements) of compromised electric reliability.

The EPA solicits comment on whether approaches to retirement in other rules have worked particularly well and might be adopted here. The EPA solicits comment on whether this subcategory would adversely incentivize coal-fired boilers planning to retire after 2028 to accelerate their retirement to 2028, as well as alternatives for addressing the disproportionate costs, energy requirements, and intersection with the CCR rule discussed above. The EPA also solicits comment 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. For example, the EPA solicits comment on data and information demonstrating that boilers that are repowered with gas units are unable to finance both the repowering and the FGD and BA technology upgrades applicable to the rest of the industrial category, and whether BAT for such units should also be established based on surface impoundments as for retiring units described above. The EPA solicits comment on whether 2028 is the most appropriate target date for retirement or if a date earlier or later than 2028 would be more appropriate. The EPA also solicits comment on whether an additional subcategory for low utilization boilers retiring by a date certain that is after 2028 would be warranted, and what an appropriate retirement date might be. The EPA requests commenters identify and include available data or information to support their recommended approach.

D. Availability Timing of New Requirements

Where BAT limitations in the 2015 rule are more stringent than previously established BPT limitations for FGD wastewater and BA transport water, those limitations, under the compliance dates as amended by the 2017 postponement rule, do not apply until a date determined by the permitting authority that is “as soon as possible” beginning November 1, 2020.[71] The rule also specifies the factors that the permitting authority must consider in determining the “as soon as possible” date.[72] In addition, the 2017 postponement rule did not revise the 2015 rule’s “no later than” date of December 31, 2023, for implementation because, as public commenters pointed out, without such a date, implementation could be substantially delayed, and a firm “no later than” date creates a more level playing field across the industry. As the EPA did in developing the 2015 rule, as part of the consideration of the technological availability and economic achievability of the BAT limitations in this proposal, the Agency considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the proposed requirements. As discussed below, the EPA is considering availability of the technologies for FGD wastewater and BA transport water.

In the 2015 rule, and as amended by the 2017 postponement rule, the EPA selected the time frames described above to enable many facilities to raise needed capital, plan and design

[71] 40 CFR 423.11(t).

[72] These factors are: (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. 40 CFR 423.11(t)

systems, procure equipment, and then construct and test systems. The time frames 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). The EPA understands that some facilities may have already installed, or are now installing, technologies that could comply with the proposed limitations. While these facilities could therefore potentially comply with the proposed rule by the earliest date on which the limitations may become applicable (November 1, 2020), the EPA solicits comment on whether the earliest date on which facilities may have to meet the proposed limitations should be later than November 1, 2020.[73]

As described previously, the industry continues to shift away from the use of surface impoundments for handling BA. Information collected since the 2015 rule, as well as conversations with electric utilities, EPA understands that facilities may be able to complete design, procurement, installation, and operation of BA transport water technologies by December 31, 2023.[74] The CCR rule proposal would require the majority of unlined surface impoundments to stop receiving waste by August 2020. This would necessarily require installation by August 2020 of an alternative system to meet those ELG standards. As described earlier, because the record for the 2015 CCR rule found that it would be less costly for facilities to install under-boiler or remote drag chain systems and send BA to landfills rather than continue to wet sluice BA and replace unlined ponds with composite lined ponds. Flexibility for facilities to comply with BAT limitations for BA transport water beyond 2023 is not necessary because the process

[73] The EPA received a request on behalf of two Maryland facilities that the EPA issue a rule postponing the earliest compliance date from November 1, 2020 to November 1, 2022. *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.

[74] Information in the record indicates a typical timeframe of 15-23 months to raise capital, plan and design systems, procure equipment, and construct a dry handling or closed-loop or high rate recycle BA system.

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. The EPA solicits comment on whether these assumptions are appropriate. The EPA also solicits comment on whether it should modify the existing language which explicitly allows permitting authorities to consider extensions granted under the CCR rule in establishing compliance dates for BA transport water. The EPA requests commenters identify and include available data or information to support their recommended approach.

For FGD wastewater, the EPA proposes to continue the existing "beginning" date, but proposes a different "no later than" date. The EPA collected updated information regarding the technical availability of the proposed FGD BAT technology basis, including the proposed VIP alternative. Based on the engineering dependency charts, bids, and other analytical documents in the current record, individual facilities may need two to three years from the effective date of any rule to install and begin operating a treatment system to achieve BAT.[75] While 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. As was the case with BA transport water above, facilities with FGD wastewater have continued to convert away from surface impoundments, and the majority of facilities with unlined surface impoundments would have to stop receiving waste in those unlined surface impoundments by August 2020, under the CCR proposal. To stop receiving waste in an unlined surface impoundment, a facility

[75] 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.

would need to construct a treatment system to meet applicable ELGs, such as a tank-based system that meets the BPT limitations. However, biological treatment is not necessary to remove TSS, and therefore more time for implementation of the proposed BAT limitations will help to accommodate the process changes necessitated by combining chemical precipitation and LRTR, and alleviate competition for resources. Considering all the factors described above, the EPA proposes to extend the "no later than" date for compliance with BAT FGD wastewater limitations to December 31, 2025, based on the proposed technology basis. Thus, for FGD wastewater, where BAT limitations are more stringent than previously established BPT limitations, BAT limitations would not apply until a date determined by the permitting authority that is as soon as possible beginning November 1, 2020, but no later than December 31, 2025. The EPA solicits comment on whether these assumptions are appropriate and whether these compliance dates should be harmonized with the compliance dates for BA transport water. The EPA requests commenters identify and include available data or information to support their recommended approach.

In addition, as discussed earlier, the EPA is proposing to give facilities that elect to use the VIP until December 31, 2028, to meet the VIP limitations, which are based on membrane filtration technology. That is the date on which the EPA proposes to determine that the membrane filtration-based limitations are "available" (as that term is used in the CWA) to all plants that might choose to participate in the voluntary incentives program. The EPA is proposing to give facilities sufficient time to work out operational issues related to being the first facilities in the U.S. to treat FGD wastewater using membrane filtration at full scale, as well as having to dispose of the resulting brine. Both issues contribute to the EPA's proposed decision that membrane filtration is not BAT on a nationwide basis at this time. The EPA also wants to incentivize facilities to opt into a program that can achieve significant pollutant reductions.

E. Regulatory Sub-Options to Address Bromides

The 2015 rule rejected thermal evaporation technology as the basis for BAT and therefore did not establish limitations for bromides in FGD wastewater. Section XVI.D of the preamble noted that the VIP established in the 2015 rule would address bromide through the limitations for TDS. The newly proposed VIP includes limits for bromide. Because the EPA proposes to provide more flexible VIP limits on other pollutants and more flexible VIP timing, the EPA estimates that selecting the proposed VIP may be the least-cost option for some facilities. The facilities that the EPA estimates VIP may be the least-cost option range in FGD wastewater flows, nameplate capacity, capacity utilization, and location. The EPA cost estimates for the VIP tend to be lower at facilities where no treatment has been installed beyond surface impoundments, however even for this group of facilities biological systems are still often least-cost. Thus, while the EPA estimates that the proposed revisions to the VIP may address bromide at more facilities than the 2015 VIP, it is still a voluntary program, and concerns about costs, availability, and disposal of the resultant brine are still present.

The EPA suggested in the preamble to the 2015 rule that water-quality-based effluent limitations 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. Since that time, few states have begun to monitor bromide discharges and it is unclear how many have acted to address such discharges.[76]

[76] The EPA is aware that Pennsylvania, Alabama, and North Carolina conduct bromide monitoring at multiple facilities with FGD discharges.

On June 8, 2018, drinking water utilities sent a letter to the EPA requesting that the Agency consider three regulatory BAT/PSES technology options to reduce bromide discharges in FGD wastewater: (1) zero liquid discharge technologies (ZLD), such as membrane filtration or thermal treatment; (2) treatment with reverse osmosis; or (3) a requirement that facilities provide data to the state permitting authority for use in calculating a site-specific discharge limitation. For the reasons explained earlier in this section, the EPA is not proposing to base BAT limitations or PSES for FGD wastewater at all existing units based on membrane filtration or thermal treatment. The EPA proposes a water quality-based approach as the most appropriate approach and solicits comment on that alternative, including ways that such an alternative could be strengthened. However, in light of the letter from the drinking water utilities and the limited state action since the 2015 rule to address this potential issue, the 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 water quality-based effluent limitations:[77] (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. Each of these are described in more detail below.

In the case of FGD wastewater monitoring, the EPA solicits comment on two approaches suggested by electric utilities. Under the first approach, bromide would be monitored monthly for two years, and thereafter only after specific changes in facility operations that could alter bromide concentrations in FGD wastewater. Such operational changes could include changing to

[77] These sub-options would not be applicable to the VIP limitations as those limitations would control bromide (and other halogens) in FGD wastewater discharges.

a brominated refined coal, a bromide addition process, a coal feedstock with higher bromide levels, or use of brominated powdered activated carbon (PAC). Under the second approach, bromide would be monitored monthly for five years in two locations to better capture bromide variability. The first monitoring location would be of intake water not affected by the site's discharge to capture what fraction of bromide is present from background surface water. The second would be of discharge water to capture the amount of bromide added by various wastewaters. The monitoring point for the FGD wastewater discharge could be at the final outfall. The EPA also solicits comment on whether monitoring should be longer or shorter duration than proposed and if additional monitoring locations may be appropriate to capture other operational changes that the EPA has not identified.

The EPA solicits comment on whether a facility should develop a plan to minimize its use of bromide on a site-specific basis. Such a plan could allow a facility to consider the costs of potential approaches to minimizing bromide use in conjunction with its efforts to meet other standards (e.g., MATS). Otherwise, facilities would minimize the bromide in their discharges by switching to lower-bromide coals, reducing bromide addition, and/or cutting back on refined coal use. The EPA solicits comment on whether such a plan is appropriate for all steam electric generators and, if so, the elements that might be included in such a plan.

Regarding a bromide limitation based on product substitution, the EPA solicits comment on whether a limitation could be established that reflects the difference in concentrations naturally occurring in coal as opposed to levels found in refined coal or from other halogen applications. Alternatively, the EPA solicits comment on whether facilities could certify that they do not burn refined coal and/or use bromide addition processes. The EPA solicits data that supports development of a numerical bromide limitation, or that demonstrates a specific numerical bromide limitation to be inappropriate.

The Agency solicits input on the pros and cons of each of these bromide sub-option approaches. Finally, the Agency solicits comment on other pollutants, including other halides, discharged from steam electric facilities that may impact the formation of disinfection byproducts (DBPs).

F. Economic Achievability

As the EPA did for the 2015 rule, the Agency performed cost and economic impact assessments using the Integrated Planning Model (IPM) to determine the effect of the proposed ELGs, using a baseline that incorporates impacts from other relevant environmental regulations (*see* Chapter 5 in RIA). At the time of the 2015 rule, the IPM model showed a total incremental closure of 843 MW of coal-fired generation as a result of the ELGs, corresponding to a net effect of two boiler closures.[78] However, since that time, natural gas prices have remained low, additional coal facilities have retired or refueled, and changes that have been proposed to several environmental regulations have been included in those model runs. Due to these changes, the EPA ran an updated version of IPM. (*See* Section VIII.C.2 for additional discussion on these updates.) This update showed that the 2015 rule resulted in the closure of 1.8 GW of coal-fired generation, corresponding to a net effect of approximately four boiler closures, based on the average capacity of coal-fired electric boilers.

The EPA similarly ran the IPM model to determine the effect of the regulatory options presented in Table VII-1. Options 2 and 4 bound the costs to industry of these four options, IPM

[78] In meetings with EPA since the 2015 rule, electric utilities have expressed concerns that IPM underpredicts closures by not accounting for the ability of facilities in regulated states to cost recover even if they would otherwise lose money or are not economical to operate.

results from these options alone reflect the range of impacts associated with all four regulatory options.[79] The IPM models for these two options were run prior to finalization of the ACE rule (the impact of ACE is analyzed in a separate sensitivity scenario) and ranged from a total net increase of 0.7 GW to 1.1 GW in coal-fired generating capacity compared to the 2015 rule, reflecting full compliance by all facilities. This capacity increase corresponds to a net effect of one to two boiler closures avoided as a result of this reconsideration action. These IPM results indicate that the proposed Option 2 is economically achievable for the steam electric power generating industry as a whole, as required by CWA section 301(b)(2)(A). Following the promulgation of the ACE rule, the EPA also conducted a sensitivity analysis that includes the effects of that rule in the ELG analytic baseline. The results of this sensitivity analysis, which are detailed in Appendix C of the RIA, also indicate that the proposed Option 2 is economically achievable. The EPA will use the latest IPM baseline, including the ACE rule as part of existing regulations, when analyzing the ELG final rulemaking.

The EPA's economic achievability analysis for this and other options is described in Section VIII, below.

G. Non-Water Quality Environmental Impacts

For the 2015 rule, the EPA performed an assessment of non-water quality environmental impacts, including energy requirements, air impacts, solid waste impacts, and changes in water use and found them to be acceptable. The EPA has reevaluated these impacts in light of the changed industry profile, as well as the proposed changes to BAT. Based on the results of these analyses the EPA determined that Options 1, 2, and 3 have acceptable non-water quality impacts.

[79] Although Option 1 includes the less stringent chemical precipitation technology, Option 2 has a greater savings due to subcategorization of low utilization boilers.

Option 4, however, would result in unacceptable non-water quality environmental impacts where management of the brine could divert FA that might otherwise be sold for use in products (e.g., replacing Portland cement in concrete) back toward placement in a landfill. *See* additional information in Section 7 of the Supplemental TDD, as well as Section X of this preamble.

H. Impacts on Residential Electricity Prices and Low-Income and Minority Populations

As the EPA did for the 2015 rule, the Agency examined the effects of today's regulatory options on consumers as an additional factor that might be appropriate when considering what level of control represents BAT. If all annualized compliance cost savings were passed on to residential consumers of electricity, instead of being borne by the operators and owners of facilities, the average monthly cost savings under any of the options would be between $0.01 and 0.04 per month as compared to the 2015 rule.

The EPA similarly evaluated the effect of today's regulatory options on minority and low-income populations. As explained in Section XII, the EPA used demographic data for populations potentially impacted by steam electric power plant discharges due to their proximity (i.e., within 50 miles) to one or more plants. For those populations, the EPA evaluated both recreational and subsistence fisher populations. The analysis described in Section XII indicates that absolute changes in human health impacts are smaller than the overall impacts resulting from the 2015 rule. However, low-income and minority populations are potentially affected to a greater degree than the general population by discharges from steam electric facilities and are expected to also accrue to a greater degree than the general population the benefits of the proposed rule, positive or negative.

I. Additional Rationale for the Proposed PSES

The 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.

With respect to BA, the EPA notes that facilities converting to dry handling or recycling all of their BA transport water would continue to perform as the zero discharge systems the EPA used in its 2015 rule pass-through analysis. 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 and to subject such direct discharges to TSS limitations of BPT. Consistent with the 2015 rule pass through analysis, TSS is not considered to pass through and the EPA would not establish TSS limitations under PSES.

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.[80] The EPA proposes these technologies as the bases for PSES for the same reasons that

[80] 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.

the EPA proposes the technologies as the bases for BAT, and also proposes the same subcategories proposed for BAT.[81]

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 CWA section 307(b)(1), 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).

VIII. Costs, Economic Achievability, and Other Economic Impacts

The EPA evaluated the costs and associated impacts of the proposed regulatory options on existing boilers at steam electric facilities. These costs are analyzed within the context of compounding regulations and other industry trends that have affected steam electric facilities profitability and generation. These include the impacts of existing environmental regulations

---

[81] Where any of the subcategories would establish BAT based on surface impoundments, with a restriction on TSS, there would be no such parallel restriction for the analogous PSES subcategory because POTWs effectively treat TSS.

(e.g., Cross-State Air Pollution Rule, Mercury and Air Toxics Standards, CWA section 316(b) rule, final CCR rule, final ACE rule), as well as other market conditions described in Section V.B.[82] This section provides an overview of the methodology the EPA used to assess the costs and the economic impacts and summarizes the results of these analyses. *See* the RIA in the docket for additional detail.

In developing ELGs, and as required by CWA section 301(b)(2)(A), the EPA evaluates the economic achievability of regulatory options to assess the impacts of applying the limitations and standards on the industry as a whole, which typically includes an assessment of incremental facility closures attributable to a regulatory option. As described in more detail below, this proposed ELG is expected to provide cost savings when compared to the baseline. Like the prior analysis of the 2015 rule, the cost and economic impact analysis for this proposed rulemaking focuses on understanding the magnitude and distribution of compliance cost savings across the industry, and the broader market impacts.

The EPA used certain indicators to assess the impacts of the proposed regulatory options on the steam electric power generating industry as a whole. These indicators are consistent with those used to assess the economic achievability of the 2015 rule (80 FR 67838); however, for this proposal, the EPA compared the values to a baseline that reflects implementation of existing environmental regulations (as of this proposal), including the 2015 rule. In the 2015 rule analysis, the costs of achieving the 2015 rule requirements were reflected in the policy cases analyzed rather than the baseline. Here, the baseline appropriately includes costs for achieving the 2015 rule limitations and standards, and the policy cases show the impacts resulting from

[82] As discussed above, impacts of the final ACE rule will be incorporated into this analysis after proposal, but were not included here as the analyses for these proposed ELGs were completed prior to the ACE rule being finalized.

changes to those existing 2015 limitations and standards. More specifically, the EPA considered the total cost to industry and change in the number and capacity of specific boilers and facilities expected to close under the options in this proposal (including proposed Option 2) compared to the estimated baseline costs. The EPA also analyzed the ratio of compliance costs to revenue to see how the proposed regulatory options change the number of facilities and their owning entities that exceed certain thresholds indicating potential financial strain.

In addition to the analyses supporting the economic achievability of the regulatory options, the EPA conducted other analyses to (1) characterize other potential impacts of the regulatory options (e.g., on electricity rates), and (2) to meet the requirements of Executive Orders or other statutes (e.g., Executive Order 12866, Regulatory Flexibility Act, Unfunded Mandates Reform Act).

A. Facility-Specific and Industry Total Costs

The EPA estimated facility-specific costs to control FGD wastewater and BA transport water discharges at existing boilers at steam electric facilities to which the ELGs apply.[83] The EPA assessed the operations and treatment system components currently in place at a given unit (or expected to be in place as a result of other existing environmental regulations), identified equipment and process changes that facilities would likely make to meet the 2015 rule (for baseline) and each of the four regulatory options presented in Table VII-1, and estimated the cost to implement those changes. As explained in the Supplemental TDD, the baseline also accounts for additional announced unit retirements, conversions, and relevant operational changes that have occurred since the EPA promulgated the 2015 rule. The EPA thus derived facility-level capital and O&M costs for controlling FGD wastewater and BA transport water using the

[83] The EPA did not estimate costs for other wastestreams not in this proposal.

technologies that form the bases of the 2015 rule, and for each regulatory option presented in Table VII-1 for existing sources. *See* Section 5 of the Supplemental TDD for a more detailed description of the methodology the EPA used to estimate facility-level costs for this proposal.

Following the same methodology used for the 2015 rule analysis, the EPA used a rate of seven percent to annualize one-time costs and costs recurring on other than on an annual basis over a specific useful life, implementation, and/or event recurrence period. For capital costs and initial one-time costs, the EPA used 20 years. For O&M costs incurred at intervals greater than one year, EPA used the interval as the annualization period (3 years, 5 years, 6 years, 10 years). The EPA added annualized capital, initial one-time costs, and the non-annual portion of O&M costs to annual O&M costs to derive total annualized facility costs. The EPA then calculated total industry costs by summing facility-specific annualized costs. For the assessment of industry costs, the EPA considered costs on both a pre-tax and after-tax basis. Pre-tax annualized costs provide insight on the total expenditure as incurred, while after-tax annualized costs are a more meaningful measure of impact on privately owned for-profit facilities and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. The EPA uses pre- and/or after-tax costs in different analyses, depending on the concept appropriate to each analysis (e.g., social costs are calculated using pre-tax costs whereas cost-to-revenue screening-level analyses are conducted using after-tax costs).

Table VIII–1 summarizes estimates of incremental pre- and post-tax industry costs for the four regulatory options presented in Table VII-1 as compared to the baseline. All four options provide cost savings (negative incremental costs) as compared to the costs that the industry would incur under the 2015 rule. Under all four options, some savings are attributable to cheaper high recycle rate BA systems. Under Options 1, 2, and 3, additional savings are due to lower cost

FGD wastewater treatment systems (chemical precipitation and LRTR). Under Option 2, further savings are attributable to the subcategorization of low utilization boilers. Finally, some cost savings are due to the changes in compliance timeframes discussed above in Section VII.D. The after-tax savings range from approximately $26 million under Option 4 to $147 million under Option 2.[84]

TABLE VIII-1. Estimated Total Annualized Industry Costs (Million of 2018$, seven percent discount rate)

Regulatory Option	Pre-tax	After-tax
Option 1	-$165.6	-$136.6
Option 2	-$175.6	-$146.5
Option 3	-$126.3	-$105.9
Option 4	-$25.5	-$26.4

B. Social Costs

Social costs are the costs of the proposed rule from the viewpoint of society as a whole, rather than the viewpoint of regulated facilities (which are private costs). In calculating social costs, the EPA tabulated the pre-tax costs in the year when they are estimated to be incurred. As described in Section VII.D of this preamble, the proposed compliance deadlines and therefore the expected technology implementation years vary across the regulatory options. The EPA performed the social cost analysis over a 27-year analysis period of 2021-2047, which combines the length of the period during which facilities are anticipated to install the control technologies (which could be as late as 2028 under Option 4) and the useful life of the longest-lived technology installed at any facility (20 years). The EPA calculated the social cost of the proposed rule using both a three percent discount rate and an alternative discount rate of seven percent.

[84] In response to additional information the EPA received from a vendor showing installed costs of LRTR were lower than EPA's predicted costs, and to account for the small difference in cost between the sand filter and ultrafiltration polishing stage technologies, the EPA conducted a sensitivity analysis (DCN SE07120). Based on this analysis, the costs to install LRTR may be approximately five percent lower than the LRTR cost estimates used for developing the total costs presented in Table VIII-1.

Social costs include costs incurred by both private entities and the government (e.g., in implementing the regulation). As described further in Chapter 10 of the RIA, the EPA did not evaluate the incremental increase in the cost to state governments to evaluate and incorporate BPJ into NPDES permits. EPA solicits comments on whether these incremental costs are significant enough to be included. Consequently, the only category of costs used to calculate social costs are those pre-tax costs estimated for steam electric facilities. Note that the annualized social costs presented in Table VIII-2 for the seven percent discount rate differ from comparable pre-tax industry compliance costs shown in Table VIII-1. The costs in TableVIII-1 represent the annualized costs of each option if they were incurred in 2020, whereas the annualized costs in Table VIII-2 are estimated based on the stream of future costs starting in the year that individual facilities are projected to actually comply with the requirements of the proposed options under the availability timing proposed in Section VII.D.

Table VIII-2 presents the total annualized social costs of the four regulatory options presented in Table VII-1, compared to the baseline and calculated using three percent and seven percent discount rates. All four options provide cost savings (negative incremental costs) compared to the baseline using a seven percent discount rate, and Options 1, 2, and 3 also show cost savings using a three percent discount rate. Option 2 has estimated annualized cost savings of $166.2 million using a seven percent discount rate and $136.3 million using a three percent discount rate.

Table VIII-2. Estimated Total Annualized Social Costs (Million of 2018$, three and seven percent discount rate)

Regulatory Option	3% Discount Rate	7% Discount Rate
Option 1	-$130.6	-$154.0
Option 2	-$136.3	-$166.2
Option 3	-$90.1	-$119.5
Option 4	$11.9	-$27.3

C. Economic Impacts

The EPA assessed the economic impacts of this proposed rule in two ways: (1) a screening-level assessment of the cost impacts on existing boilers at steam electric facilities and the entities that own those facilities, based on comparison of costs to revenue; and (2) an assessment of the impact of the regulatory options presented in Table VII-1 within the context of the broader electricity market, which includes an assessment of changes in predicted facility closures attributable to the options. The following sections summarize the results of these analyses. The RIA discusses the methods and results in greater detail.

The first set of cost and economic impact analyses—at both the facility and parent company levels— provide screening-level indicators of the impacts of costs for FGD wastewater and BA transport water controls relative to historical operating characteristics of steam electric facilities incurring those costs (i.e., level of electricity generation and revenue). The EPA conducted these analyses for the baseline and for the four regulatory options presented in Table VII-1, and then compared these impacts to understand the incremental effects of the regulatory options in this proposal. The second set of analyses look at broader electricity market impacts considering the interconnection of regional and national electricity markets. It also looks at the distribution of impacts at the facility and boiler level. This second set of analyses provides insight on the impacts of the regulatory options in this proposal on steam electric facilities, as well as the electricity market as a whole, including changes in generation capacity, generation, and wholesale electricity prices. The market analysis compares model predictions for the options to a base case that includes the predicted and observed economic and market effects of the 2015 rule. The EPA used results from the screening analysis of facility- and entity- level impacts, together with changes in projected capacity closure from the market model, to understand the impacts of the regulatory options in this proposal relative to the baseline.

1. Screening-Level Assessment

The EPA conducted a screening-level analysis of each regulatory option's potential impact to existing boilers at steam electric facilities and parent entities based on cost-to-revenue ratios. For each of the two levels of analysis (facility and parent entity), the Agency assumed, for analytic convenience and as a worst-case scenario, that none of the compliance costs would be passed on to consumers through electricity rate increases and would instead be absorbed by the steam electric facilities and their parent entities. This assumption overstates the impacts of compliance expenditures since steam electric facilities that operate in a regulated market may be able to pass on changes in production costs to consumers through changes in electricity prices. It is, however, an appropriate assumption for a screening-level estimate of the potential cost impacts.

a. Facility-Level Cost-to-Revenue Analysis

The EPA developed revenue estimates for this analysis using EIA data. The EPA then calculated the change in the annualized after-tax costs of the four regulatory options presented in Table VII-1 as a percent of baseline annual revenues. *See* Chapter 4 of the RIA for a more detailed discussion of the methodology used for the facility-level cost-to-revenue analysis.

Cost-to-revenue ratios are used to describe impacts to entities because they provide screening-level indicators of potential economic impacts. Just as for the facilities owned by small entities under guidance in U.S. EPA (2006),[85] the full range of facilities incurring costs below

[85] U.S. EPA (Environmental Protection Agency). 2006. EPA's Action Development Process: Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory

one percent of revenue are unlikely to face economic impacts, while facilities with costs between one percent and three percent of revenue have a higher chance of facing economic impacts, and facilities incurring costs above three percent of revenue have a still higher probability of economic impacts.

As a result of the 2015 rule (baseline), the EPA estimated that 18 facilities incur costs greater than or equal to one percent of revenue, including six facilities that have costs greater than or equal to three percent of revenue, and an additional 96 facilities incur costs that are less than one percent of revenue. By contrast, the four regulatory options the EPA analyzed for this proposal are estimated to provide cost savings that reduce this impact to various degrees, with Option 2 showing the largest reductions in cost. Options 1, 3, and 4 show an estimated 16 to 19 facilities with costs greater than or equal to one percent of revenue, including four or five facilities with costs greater than or equal to three percent of revenue. Under Option 2, the EPA estimated that eight facilities incur costs greater than or equal to one percent of revenue, including two facilities that have costs greater than or equal to three percent of revenue, and an additional 100 facilities incur costs that are less than one percent of revenue.

b. Parent Entity-Level Cost-to-Revenue Analysis

The EPA also assessed the economic impact of the regulatory options presented in Table VII-1 at the parent entity level. The screening-level cost-to-revenue analysis at the parent entity level provides insight on the impact on those entities that own existing boilers at steam electric facilities. In this analysis, the domestic parent entity associated with a given facility is defined as that entity with the largest ownership share in the facility. For each parent entity, the EPA

Enforcement Fairness Act. November 2006. Available online at: *https://www.epa.gov/reg-flex/epas-action-development-process-final-guidance-epa-rulewriters-regulatory-flexibility-act*.

compared the incremental change in the total annualized after-tax costs and the total revenue for the entity compared to the baseline (*see* Chapter 4 of the RIA for details). Following the methodology employed in the analyses for the 2015 rule (80 FR 67838), the EPA considered a range of estimates for the number of entities owning an existing boiler at a steam electric power facility to account for partial information available for steam electric facilities that are not expected to incur ELG compliance costs.

Similar to the facility-level analysis above, cost-to-revenue ratios provide screening-level indicators of potential economic impacts, this time to the owning entities; higher ratios suggest a higher probability of economic impacts. The EPA estimated that the number of entities owning existing boilers at steam electric facilities ranges from 243 (lower-bound estimate) to 478 (upper-bound estimate), depending on the assumed ownership structure of facilities not incurring ELG costs and not explicitly analyzed. The EPA estimates that in the baseline 236 to 470 parent entities, respectively, would either incur no costs or the annualized cost they incur to meet the 2015 rule BAT limitations and pretreatment standards would represent less than one percent of their revenues.

Compared to the baseline, all four regulatory options reduce the impacts on the small number of entities incurring costs. The changes are greatest for Option 2, which has five fewer entities with costs exceeding one percent of revenue, including one less entity with costs exceeding three percent of revenue, with the remaining entities either having no cost, or costs that are less than one percent of revenue. Options 1 and 3 each have two fewer entities in the one to three percent of revenue category, and Option 4 has one fewer entity in the one to three percent of revenue category.

2. Electricity Market Impacts

In analyzing the impacts of regulatory actions affecting the electric power sector, the EPA used IPM, a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. The model is designed to evaluate the effects of changes in boiler-level electric generation costs on the total cost of electricity supply, subject to specified demand and emissions constraints. Use of a comprehensive, market analysis system is important in assessing the potential impact of any power facility regulation because of the interdependence of electric boilers in supplying power to the electric transmission grid. Changes in electricity production costs at some boilers can have a range of broader market impacts affecting other boilers, including the likelihood that various units are dispatched, on average. The analysis also provides important insight on steam electric capacity closures (e.g., retirements of boilers that become uneconomical relative to other boilers), or avoided closures, based on a more detailed analysis of market factors than in the screening-level analyses above. The results further inform the EPA's understanding of the potential impacts of the regulatory options presented in Table VII-1. For the current analyses, the EPA used version 6 (V6) of IPM to analyze the impacts of the regulatory options. IPM V6 is based on an inventory of U.S. utility- and non-utility-owned boilers and generators that provide power to the integrated electric transmission grid, including facilities to which the ELGs apply. IPM V6 embeds an energy demand forecast that is derived from DOE's "Annual Energy Outlook 2018" (AEO 2018). IPM V6 also incorporates the expected compliance response to existing regulatory requirements for regulations affecting the power sector (e.g., Cross-State Air Pollution Rule (CSAPR) and CSAPR Update Rule, Mercury and Air Toxics Rule (MATS), the Cooling Water Intake Structure (CWIS) rule, and 2015 CCR rule, as well as the 2015 rule). Federal CO_2 standards for existing sources are not modeled in IPM V6, owing to ongoing litigation.

The EPA analyzed proposed Option 2 and Option 4 using IPM V6. As discussed in Section VIII.A, these two options have the greatest and least cost savings, respectively, compared to the baseline, and therefore reflect the full range of potential impacts from the regulatory options in this proposal. In addition, following promulgation of the ACE final rule, EPA also analyzed proposed Option 2 relative to a baseline that includes the ACE rule. *See* Appendix C in the RIA for details of these results.

In contrast to the screening-level analyses, which are static analyses and do not account for interdependence of electric boilers in supplying power to the electricity transmission grid, IPM V6 accounts for potential changes in the generation profile of steam electric and other boilers and consequent changes in market-level generation costs, as the electric power market responds to changes in generation costs for steam electric boilers due to the regulatory options. Additionally, in contrast to the screening-level analyses, in which the EPA assumed no cost pass through of ELG compliance costs, IPM V6 depicts production activity in wholesale electricity markets where the specific increases in electricity prices for individual markets would result in some recovery of compliance costs for plants in those markets.

In analyzing the regulatory options presented in Table VII-1, the EPA estimated changes in fixed and variable costs for the steam electric facilities and boilers already incurring costs in the baseline to instead incur costs (or avoid incurring costs) to comply with Option 2 and Option 4. Because IPM is not designed to endogenously model the selection of wastewater treatment technologies as a function of electricity generation, effluent flows, and pollutant discharge, the EPA estimated these costs exogenously for each steam electric generating unit and input these costs into the IPM model as fixed and variable O&M cost adders. The EPA then ran IPM V6 including these new cost estimates to determine the dispatch of electric boilers that would meet projected demand at the lowest costs, subject to the same constraints as those present in the baseline analysis. The estimated changes in facility- and boiler-specific production levels and costs—and, in turn, changes in total electric power sector costs and production profile—are key data elements in evaluating the expected national and regional effects of the regulatory options in this proposal, including closures or avoided closures of steam electric boilers and facilities. The EPA considered impact metrics of interest at three levels of aggregation: (1) impact on national and regional electricity markets (all electric power generation, including steam and non-steam electric facilities); (2) impact on steam electric facilities as a group, and (3) impact on individual steam electric facilities incurring costs. Chapter 5 of the RIA discusses the first analysis; the sections below summarize the last two, which are further described in Chapter 5 and in Appendix C of the RIA. All results presented below are representative of modeled market conditions in the years 2028–2033, when the rule would either be implemented or plans for implementation by the end of 2028 would be well underway at all facilities.

a. Impacts on Existing Steam Electric Facilities

The EPA used IPM V6 results for 2030[86] to assess the potential impact of the regulatory options presented in Table VII-1 on existing boilers at steam electric facilities. The purpose of this analysis is to assess any fleetwide changes from baseline impacts on boilers at steam electric facilities. Table VIII-3 reports estimated results for existing boilers at steam electric facilities, as a group. The EPA looked at the following metrics: (1) incremental (and avoided) early retirements and capacity closures, calculated as the difference between capacity under the regulatory option and capacity under the baseline; (2) incremental capacity closures as a percentage of baseline capacity; (3) change in electricity generation from facilities regulated by

[86] IPM model year 2030 represents years 2028-2033.

ELGs; (4) changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; and (5) changes in annual costs (fuel, variable O&M, fixed O&M, and capital). Note that changes in electricity generation presented in Table VIII-3 are attributable both to changes in retirements, as well as changes in capacity utilization at boilers and plants whose retirement status does not change.

Table VIII-3. Estimated Impact on Steam Electric Facilities as a Group at the Year 2030

Metric	Baseline Value	Change Attributable to Regulatory Option as Compared to Baseline			
		Option 2		Option 4	
		Value	Percent	Value	Percent
Total capacity (MW)	336,872	2,880	0.9%	3,194	0.9%
Early retirements or closures[a] (MW)	58,192	-2,880	-4.9%	-3,194	-5.5%
Early retirements or closures[a] (number of plants)	79	0	0.0%	-1	-1.3%
Total generation (GWh)	1,570,513	4,676	0.3%	1,235	0.1%
Variable production cost (2018$/MWh)	$26.00	$0.02	0.1%	$0.05	0.2%
Annual costs (million 2018$)	$60,298	$98	0.2%	$103	0.1%

[a] Values for incremental early retirements or closures represent change relative to the baseline. IPM may show partial (unit) or full facility early retirements (closures). It may also show avoided closures (negative closure values) in which a boiler or facility that is projected to close in the baseline is estimated to continue operating in the policy case.

Under proposed Option 2, generation at steam electric facilities is projected to increase by 4,676 GWh (0.3 percent) nationally, when compared to the baseline. IPM V6 projects a net increase in total steam electric capacity by 2,880 MW or approximately 0.9 percent of total baseline capacity, but no net change in the number of full facility retirements and the net avoidance of three partial retirements (unit closures) nationwide indicating a higher capacity utilization by these facilities. *See* Section 5.2.2.2 in the RIA for details.

IPM V6 projects generation at steam electric facilities increases under Option 4 by 1,235 GWh (0.1 percent) nationally, which is smaller in magnitude than the increase under Option 2.

National level results for steam electric facilities under Option 4 show an increase in total steam electric capacity of 3,194 MW (0.9 percent of the baseline). At the national level, IPM projects one net avoided full facility closure and the same three avoided partial retirements as for Option 2. *See* Section 5.2.2.2 in the RIA for details.

These findings suggest that all of the regulatory options in this proposal can be expected to have small economic consequences for the steam electric facilities as a group. Options 2 and 4 also affect the operating status of very few steam electric facilities, with no net change in facility closures under Option 2, and one net avoided closure under Option 4.[87] For further discussion of closures and related distributional impacts, see Chapter 5 of the RIA.

Because the analysis of the proposed options discussed in the RIA was completed before the EPA finalized the ACE rule, this analysis does not include the projected effects of the ACE rule. Thus, the EPA conducted a supplemental IPM run with the costs of Option 2 on a baseline that includes the ACE illustrative case presented in the ACE final rule (*see* Appendix C in RIA). A summary of these results is presented in Table VIII-4.

Table VIII-4. Estimated Impact of ELG Option 2 on Steam Electric Power Plants as a Group at the Year 2030, for Sensitivity Analysis Including ACE Final Rule

Metric	Baseline with ACE Rule	Option 2 with ACE Rule		
		Value	Difference	Percent Change
Early retirements or closures[a] (MW)	336,547	339,654	-3,107	-0.9%
Early retirements or closures[a] (number of plants)	78	79	1	1.3%
Total generation (GWh)	1,569,109	1,576,455	7,345	0.5%
Variable production cost (2018$/MWh)	$25.85	$25.87	$0.02	0.1%
Annual costs (million 2018$)	$60,387	$60,578	$191	0.3%

[87] The additional closure under Option 2 is not a result of the facility incurring costs under this proposed rule. The IPM model predicts this facility becomes uneconomical due to the increased generation from other coal facilities in the same NERC region.

[a] Values for incremental early retirements or closures represent change relative to the baseline. IPM may show partial (unit) or full facility early retirements (closures). It may also show avoided closures (negative closure values) in which a boiler or facility that is projected to close in the baseline is estimated to continue operating in the policy case.

Examining the incremental impacts of Option 2 on a baseline including ACE, generation at steam electric facilities is projected to increase by 3,107 GWh (0.9 percent) nationally. IPM V6 projects a net increase in total steam electric capacity by 7,345 MW or approximately 0.5 percent of total baseline capacity. There is one incremental full facility retirement as well as the net avoidance of four partial retirements (unit closures) nationwide indicating a higher capacity utilization by these facilities. See Appendix C of the RIA for further details.

b. Impacts on Individual Facilities Incurring Costs

To assess potential facility-level effects, the EPA also analyzed facility-specific changes attributable to the regulatory options in Table VII-1 for the following metrics: (1) Capacity utilization (defined as annual generation (in MWh) divided by [capacity (MW) times 8,760 hours]) (2) electricity generation, and (3) variable production costs per MWh, defined as variable O&M cost plus fuel cost divided by net generation. The analysis of changes in individual facilities is detailed in Chapter 5 of the RIA.

The results for both Option 2 and Option 4 show no change, or less than a one percent reduction or one percent increase for steam electric facilities projected to incur ELG compliance costs. For Option 2, a greater number of facilities see improving operating conditions (i.e., higher capacity utilization or generation, lower variable production costs) than deteriorating conditions. Effects under Option 4 are similar, although approximately the same number of facilities see positive changes in operating conditions as negative changes. Thus, the results for the subset of facilities incurring costs further support the conclusion that the effects of any of the regulatory options in this proposed rule on the steam electric power generating industry will be less than that of the 2015 rule. This conclusion holds when including the effects of the ACE final rule, as detailed in Appendix C of the RIA for proposed Option 2.

IX. Changes to Pollutant Loadings

In developing ELGs, the EPA typically evaluates the pollutant loading reductions of regulatory options to assess the impacts of the compliance requirements on discharges from the industry as a whole. In estimating pollutant reductions associated with this proposal, the EPA took the same approach as described above for facility-specific costs. That is, the EPA compared the values to a baseline that reflects implementation of existing environmental regulations, including the 2015 rule. In the 2015 rule, the baseline did not reflect pollutant loading reductions for achieving the 2015 rule requirements as that impact is what EPA analyzed. Here, the baseline appropriately includes pollutant loading reductions for achieving the 2015 rule requirements as the EPA is analyzing the impact resulting from any changes to those requirements. More specifically, the EPA considered the change in the pollutant loading reductions associated with the regulatory options in this proposal to those projected under the baseline.

The general methodology that the EPA used to calculate pollutant loadings is the same as that described in the 2015 rule. The EPA used data collected for the 2015 rule, as well as the data described in Section VI, to characterize pollutant concentrations for FGD wastewater and bottom ash transport water. The EPA evaluated these data sources to identify analytical data that meet EPA's acceptance criteria for inclusion in analyses for characterizing discharges of FGD wastewater and bottom ash transport water. For each plant discharging FGD wastewater or bottom ash transport water, the EPA used data from the 2009 survey and/or industry-submitted data to determine the discharge flow rates for FGD wastewater and bottom ash transport water. The EPA adjusted the discharge flow rates used in the pollutant loadings estimates to account for retirements, fuel conversions, and other changes in operations scheduled to occur by December 31, 2028, described in Section 6 of the Supplemental TDD, that will eliminate or alter the discharge of an applicable wastestream. Finally, the Agency adjusted the discharge flow rates to account for changes in plant operations to optimize FGD wastewater flows and to comply with the CCR rule. For further discussion of these adjustments see Section 6.2.2 and 6.3.2 of the Supplemental TDD, respectively.

The EPA first estimated—on an annual, per facility basis—the pollutant discharge load for FGD wastewater and BA transport water associated with the technology basis evaluated for facilities to comply with the 2015 rule requirements for FGD wastewater and BA transport water relative to the conditions currently present or planned at each facility. The EPA similarly estimated facility-specific post-compliance pollutant loadings associated with the technology bases for facilities to comply with effluent limitations based on each of the regulatory options in this proposal. For each regulatory option, the EPA then calculated the changes in pollutant loadings at a particular facility as the sum of the differences between the estimated baseline and post-compliance discharge loadings for each applicable wastestream.

For those facilities that discharge indirectly to POTWs, the EPA adjusted the baseline and option loadings to account for pollutant removals expected from POTWs. These adjusted pollutant loadings for indirect dischargers therefore approximate the resulting discharges to receiving waters. For additional details on the methodology the EPA used to calculate pollutant loading reductions, *see* Section 6 of the Supplemental TDD.

A. FGD Wastewater

For FGD wastewater, the EPA continued to use the average pollutant effluent concentration with facility-specific discharge flow rates to estimate the mass pollutant discharge per facility for baseline and each regulatory option in Table VII-1. The EPA used data compiled for the 2015 rule as the initial basis for estimating discharge flow rates and updated the data to reflect retirements or other relevant changes in operation. For example, the EPA reviewed state and EIA data to identify flow rates for new scrubbers that have come online since the 2015 rule. The EPA also accounted for increased rates of recycle through the scrubber that would affect the discharge flow.

The EPA assigned pollutant concentrations for each analyte based on the operation of a treatment system designed to comply with the baseline or the regulatory options considered. The EPA used data compiled for the 2015 rule to characterize untreated FGD purge, chemical precipitation effluent, and chemical precipitation plus high hydraulic residence time biological reduction effluent. The EPA used data provided by industry to characterize effluent quality for chemical precipitation plus LRTR and membrane filtration effluent. In addition, the EPA used data provided by industry and other stakeholders as described in Section VI of this preamble to quantify bromide in FGD wastewater under baseline conditions and for the regulatory options.

B. BA Transport Water

The EPA estimated baseline and post-compliance loadings for each regulatory option in Table VII-1 using pollutant concentrations for BA transport water and facility-specific flow rates. The EPA used data compiled for the 2015 rule as the basis for estimating BA transport water discharge flows and updated the data set to reflect retirements and other relevant changes in operation (e.g., ash handling conversions, fuel conversions) that occurred after the 2015 rule data were collected. For the high recycle rate technology option, the EPA also estimated discharge flows associated with the purge from remote MDS operation, based on the boiler capacity and the volume of the remote MDS. Under the baseline, which reflects the 2015 rule limitation of zero discharge, the EPA estimated a flow rate of zero.

For this proposed rule, in response to the administrative petitions discussed in Section IV of this preamble, the EPA was able to use a revised set of the 2015 rule analytical data to characterize BA transport water effluent from steam electric facilities. As an example, the EPA re-evaluated and revised, as appropriate, its data sets in light of questions petitioners raised about the inclusion and validity of certain data due, in part, to what the petitioners assert are flaws in data acceptance criteria, obsolete analytical methods, and the treatment of non-detect analytical results, which petitioners believed resulted in an overestimation of pollutant loadings resulting from current practices for BA transport water, in turn resulting in an overestimation of pollutant removals under the 2015 rule. The EPA also updated the data set and incorporated BA transport water sampling data submitted by industry during the final months of the 2015 rule and as part of a voluntary sampling program described in Section VI of this preamble. For a detailed discussion, *see* Section 6 of the Supplemental TDD.

C. Summary of Incremental Changes of Pollutant Loadings from Proposed Regulatory Options

Table IX-1 summarizes the net change to annual pollutant loadings, compared to baseline, associated with each regulatory option in Table VII-1.

TABLE IX-1. Estimated Incremental Changes to Annual Pollutant Loading for Proposed Regulatory Options 1, 2, 3, and 4 [In pounds/year] Compared to Baseline

Regulatory Option[a]	Changes in Pollutant Loadings
1	13,400,000
2	-104,000,000
3	-276,000,000
4	-1,320,000,000

Note: Changes in pollutant loadings are rounded to three significant figures.

[a] Negative values represent an estimated decrease in loadings to surface waters compared to baseline. Positive values represent an estimated increase in loadings to surface waters compared to baseline.

Compared to the 2015 rule, Options 2, 3 and 4 result in decreased pollutant loadings to surface waters. Reductions under Options 2 and 3 would be realized to the extent that operators chose to meet the limitations based on membrane filtration under the proposed revisions of VIP for FGD wastewater. Under Option 2, the EPA estimated that 18 plants (27 percent of plants estimated to incur FGD compliance costs) would opt into the VIP program and under Option 3 the number rises to 23 plants (34 percent of plants estimated to incur FGD compliance costs).

X. Non-Water Quality Environmental Impacts

The elimination or reduction of one form of pollution may create or aggravate other environmental problems. Therefore, Sections 304(b) and 306 of the Act require the EPA to consider non-water quality environmental impacts (including energy impacts) associated with ELGs. Accordingly, the EPA has considered the potential impact of the regulatory options in today's proposal on air emissions, solid waste generation, and energy consumption. For the reasons described in Section IX of this preamble, the baseline for these analyses appropriately includes non-water quality environmental impacts associated with achieving the 2015 rule requirements, and the EPA is analyzing the incremental impacts resulting from the regulatory options presented in Table VII-1 compared to those projected under the baseline. In general, the EPA used the same methodology to conduct the current analysis (with updated data as applicable) as it did for the analysis supporting the 2015 rule. The following summarizes the methodology and results. *See* Section 7 of the Supplemental TDD for additional details.

A. Energy Requirements

Steam electric facilities use energy when transporting ash and other solids on or off site, operating wastewater treatment systems (e.g., chemical precipitation, biological treatment), or operating ash handling systems. For today's proposal, the EPA considered whether there would be an associated change in the incremental energy requirements compared to baseline. Energy requirements vary depending on the regulatory option evaluated and the current operations of the facility. Therefore, as applicable, the EPA estimated the increase in energy usage in megawatt hours (MWh) for equipment added to the facility systems or in consumed fuel (gallons) for transportation/operating equipment for baseline and all regulatory options. The EPA summed the facility-specific estimates to calculate the net change in energy requirements from baseline for the regulatory options.

The EPA estimated the amount of energy needed to operate wastewater treatment systems and ash handling systems based on the horsepower rating of the pumps and other equipment. The EPA also estimated the fuel consumption associated with the changes in transportation needed to landfill solid waste and combustion residuals (e.g., ash) at steam electric facilities (on-site or off-site). The frequency and distance of transport depends on a facility's operation and configuration; specifically, the volume of waste generated and the availability of either an on-site or off-site non-hazardous landfill and its distance from the facility. Table X-1 shows the net change in annual electrical energy usage associated with the regulatory options compared to baseline, as well as the net change in annual fuel consumption requirements associated with the regulatory options compared to baseline.

Table X-1. Estimated Incremental Change in Energy Requirements Associated with Regulatory Options Compared to Baseline

Non-Water Quality Impact	Energy Use Associated with Regulatory Options[a]			
	Option 1	Option 2	Option 3	Option 4
Electrical Energy Used (MWh)	-82,300	-54,570	-27,000	94,000
Fuel Used (Thousand Gallons)	0	-48,000	40,000	243,000

[a] Negative values represent a decrease in energy use compared to baseline. Positive values represent an increase in energy use compared to baseline.

B. Air Pollution

The regulatory options are expected to affect air pollution through three main mechanisms: (1) changes in auxiliary electricity use by steam electric facilities to operate wastewater treatment, ash handling, and other systems needed to meet regulatory standards; (2) changes to transportation-related emissions due to the trucking of CCR waste to landfills; and (3) the change in the profile of electricity generation due to any regulatory requirements. This section discusses air emission changes associated with the first two mechanisms and presents the corresponding estimated net change in air emissions. *See* Section XII of this preamble for additional discussion of the third mechanism.

Steam electric facilities generate air emissions from operating transport vehicles, such as dump trucks, which release criteria air pollutants and greenhouse gases when operated. Similarly, a decrease in energy use or vehicle operation would result in decreased air pollution.

To estimate the net air emissions associated with changes in electrical energy use projected as a result of the regulatory options in today's proposal compared to baseline, the EPA combined the energy usage estimates with air emission factors associated with electricity production to calculate air emissions associated with the incremental energy requirements. The EPA used emission factors projected by IPM V6 (ton/MWh) for nitrogen oxides, sulfur dioxide, and carbon dioxide to generate estimates of the changes in air emissions associated with changes in energy production for Options 2 and 4 compared to baseline.[88]

To estimate net air emissions associated with the change in operation of transport vehicles, the EPA used the MOVES2014b model to identify air emission factors (grams per

[88] Only Options 2 and 4 were run through IPM; however, extrapolated net benefits from air impacts for Options 1 and 3 are available in Chapter 8 of the Benefit Cost Analysis report.

mile) for the air pollutants of interest. The EPA estimated the annual number of miles that dump trucks moving ash or wastewater treatment solids to on- or off-site landfills would travel for the regulatory options. The EPA used these estimates to calculate the net change in air emissions for the Options 2 and 4 compared to baseline. Table X-2 presents EPA's estimated net change in air emissions associated with auxiliary electricity and transportation.

Table X-2. Estimated Net Change in Industry-Level Air Emissions associated with Auxiliary Electricity and Transportation for Options Compared to Baseline[a,b]

Non-Water Quality Impact	Change in Emissions - Option 2 (Tons/Year)[b]	Change in Emissions - Option 4 (Tons/Year)[c]
NO^x	-32.7	32.7
SO_x	-54.3	20.4
CO_2	-44,600	60,600

[a] Negative values represent a decrease in energy use compared to baseline. Positive values represent an increase in energy use compared to baseline.
[b] Option 2 estimates are based on the IPM sensitivity analysis scenario that includes the ACE rule in the baseline (IPM-ACE).
[c] Option 4 estimates are based on IPM analysis scenario that does not include the ACE rule in the baseline.

The modeled output from IPM V6 predicts changes in electricity generation due to compliance costs attributable to Options 2 and 4 compared to baseline. These changes in electricity generation are, in turn, predicted to affect the amount of NO_x, SO_2, and CO_2 emissions from steam electric facilities. A summary of the net change in annual air emissions under Options 2 and 4 for all three mechanisms is shown in Table X-3. Similar to costs, the IPM V6 results from these options reflect the range of NWQEI associated with all four regulatory options. To provide some perspective on the estimated changes in annual air emissions, EPA compared the estimated change in air emissions to the net amount of air emissions generated in a year by all electric power facilities throughout the United States. For a more details on the sources of air emission changes, *see* Section 7 of the Supplemental TDD.

Table X-3. Estimated Net Change in Industry-Level Air Emissions Associated with Changes in Electricity Generation for Options Compared to Baseline

Non-Water Quality Impact	Change in Emissions - Option 2 (Million Tons)[a]	Change in Emissions - Option 4 (Million Tons)[b]	2016 Emissions by Electric Power Generating Industry (Million Tons)
NO_x	0.005	0.001	1.47
SO_x	0.005	0.002	1.63
CO_2	5.66	1.24	2,030

[a] Option 2 emissions are based on the IPM sensitivity analysis scenario that includes the ACE rule in the baseline.
[b] Option 4 emissions are based on the IPM sensitivity analysis scenario that does not include the ACE rule in the baseline.

C. Solid Waste Generation and Beneficial Use

Steam electric facilities generate solid waste associated with sludge from wastewater treatment systems (e.g., chemical precipitation, biological treatment). The EPA estimated the change in the amount of solids generated under each regulatory option for each facility in comparison to the baseline. For FGD wastewater treatment, Regulatory Options 2, 3, and 4 result in an increase in the amount of solid waste generated compared to baseline. The solid waste generation associated with Option 1 is comparable to baseline. While BA solids are also generated at steam electric facilities, all of the BA solids accounted for in the waste volumes disposed in the 2015 rule analysis were suspended solids from combustion, and therefore the regulatory options in today’s proposal do not alter the amount of BA or other combustion residuals generated. Table X-4 shows the net change in annual solid waste generation, compared to baseline, associated with the proposed regulatory options.

Table X-4. Estimated Incremental Changes to Solid Waste Generation Associated with Regulatory Options Compared to Baseline

Non-Water Quality Impact	Solid Waste Generation Associated with Regulatory Options			
	Option 1	Option 2	Option 3	Option 4
Solids Generated (tons/year)	0	328,000	487,000	2,326,000

The EPA also evaluated the potential impacts of diverting FA from current beneficial uses toward encapsulation of brine (from membrane filtration) for disposal in landfills. According to the latest ACAA survey,[89] over half of the FA generated by coal-fired facilities is being sold for beneficial uses rather than disposed of, and the majority of this beneficially used FA is replacing Portland cement in concrete. This also holds true for the specific facilities currently discharging FGD wastewater, as seen by sales of FA in the 2016 EIA-923 Schedule 8A.[90] Summary statistics of the FA beneficial use percentage for these facilities are displayed in Table X-5 below.

Table X-5. Percent of FA Sold for Beneficial Use by Facilities Discharging FGD Wastewater.

Statistic	Percent of FA Sold for Beneficial Use
Min	0%
10th percentile	0%
25th percentile	3%
Mean	48%
Median	50%
75th percentile	88%
90th percentile	98%
Max	100%

In the EPA's coal combustion residuals disposal rule,[91] the EPA noted that FA replacing Portland cement in concrete would result in significant avoided environmental impacts to energy use, water use, greenhouse gas emissions, air emissions, and waterborne wastes. Although the EPA cannot tie specific facilities selling their FA to this specific beneficial use, over half of the FA beneficially used currently replaces Portland cement in concrete. Therefore, where sale for this particular beneficial use occurs by facilities that may otherwise use their fly ash to

[89] Available online at: *https://www.acaa-usa.org/Portals/9/Files/PDFs/2016-Survey-Results.pdf*
[90] Available online at: *https://www.eia.gov/electricity/data/eia923/*
[91] Available online at: *http://www.regulations.gov* Docket ID: EPA-HQ-RCRA-2009-0640

encapsulate membrane filtration brine under Option 4, the EPA proposes to find that unacceptable air and other non-water quality environmental impacts will result.

D. Changes in Water Use

Steam electric facilities generally use water for handling solid waste, including ash, and for operating wet FGD scrubbers. The BA handling technologies associated with baseline and the regulatory options in today's proposal for BA transport water eliminate or reduce water use associated with wet sluicing BA operating systems. The 2015 rule baseline requires zero discharge of pollutants in BA transport water, and because the use of other wastewater could significantly increase the necessary purge flow to maintain water chemistry, the EPA estimated the increase in water use for BA handling associated with Options 1, 2, 3, and 4 compared to baseline as equal to the BA purge flow.

Two of the three technology bases for FGD wastewater included in the regulatory options in today's proposal, chemical precipitation and chemical precipitation plus LRTR, are not expected to reduce or increase the amount of water use. Facilities that install a membrane filtration system for FGD wastewater treatment under Option 2 or 3 as part of the VIP option, or under Option 4, are assumed to decrease water use compared to baseline by recycling all permeate back into the FGD system, which would avoid costs of pumping or treating new makeup water. Therefore, the EPA estimated this reduction in water use resulting from membrane filtration treatment based on the estimated volume of the permeate stream from the membrane filtration system. Table X-6 sums the changes for FGD wastewater and BA transport water and shows the net change in water use, compared to baseline, for the proposed regulatory options.

Table X-6. Estimated Incremental Changes to Water Use Associated with Regulatory Options Compared to Baseline

Non-Water Quality Impact	Changes to Water Use Associated with Regulatory Options			
	Option 1	Option 2	Option 3	Option 4
Changes in Water Use (gallons/year)	3,370,000	21,100,000	613,000	-9,380,000

XI. Environmental Assessment

A. Introduction

The EPA conducted an environmental assessment for this proposed rule. The environmental assessment reviewed currently available literature on the documented environmental and human health impacts of steam electric power facility FGD wastewater and BA transport water discharges and conducted modeling to determine the impacts of pollution from the universe of steam electric facilities to which the steam electric ELGs apply. For the reasons described in Section VIII of this preamble, in conducting these analyses, the baseline appropriately evaluates environmental and human health impacts of achieving the 2015 rule requirements as the EPA is analyzing the impact resulting from any changes to those requirements compared to the 2015 rule (the same baseline used to evaluate costs). More specifically, the EPA considered the change in impacts associated with the regulatory options presented in Table VII-1 in relation to those projected under the baseline.

Information from the EPA's review of the scientific literature and documented cases of impacts of steam electric power facility FGD wastewater and BA transport water discharges on human health and the environment, as well as a description of the EPA's modeling methodology and results, are provided in the Supplemental Environmental Assessment (Supplemental EA). The Supplemental EA contains information on literature that the EPA has reviewed since the 2015 rule, updates to the modeling methodology and modeling results for each of the regulatory options in today's proposal. The 2015 EA provides information from the EPA's earlier review of the scientific literature and documented cases of the full spectrum of impacts associated with the wider range of steam electric power facility wastewater discharges addressed in the 2015 rule on human health and the environment, as well as a full description of the EPA's modeling methodology.

Current scientific literature indicates that untreated steam electric power facility wastewaters, such as FGD wastewater and BA transport water, contain large amounts of a wide range of pollutants, some of which are toxic and bioaccumulative, and which cause detrimental environmental and human health impacts. For additional information, *see* Section 2 of the Supplemental EA. The EPA also considered environmental and human health effects associated with changes in air emissions, solid waste generation, and water withdrawals. Sections X and XII discuss these effects.

B. Updates to the Environmental Assessment Methodology

The environmental assessment modeling for today's proposed rule consisted of the steady-state, national-scale immediate receiving water (IRW) model that was used to evaluate the direct and indirect discharges from steam electric facilities in the 2015 final ELG rule and 2015 final CCR rule.[92] The model focused on impacts within the immediate surface waters where the discharges occur (approximately 0.5 to 6 miles from the outfall). The EPA also modeled receiving water concentrations downstream from steam electric power facility discharges using a downstream fate and transport model (see Section XII of this preamble).

The environmental assessment also incorporates changes to the industry profile outlined in Section V of this preamble. Additionally, the EPA updated and improved several input

[92] These rules modeled the same waterbodies for which the model was peer reviewed in 2008.

parameters for the IRW model, including receiving water boundaries and volumetric flow data from National Hydrography Dataset Plus (NHDPlus) Version 2, updated national recommended water quality criteria (WQC) for cadmium and selenium, updated benchmarks for ecological impacts in benthic sediment, and an updated bioconcentration factor for cadmium.

C. Outputs from the Environmental Assessment

The EPA estimates small environmental and ecological changes associated with changes in pollutant loadings for the regulatory options presented in Table VII-1 as compared to the baseline, including small changes in impacts to wildlife and humans. More specifically, in addition to other unquantified environmental changes, the environmental assessment evaluated changes in (1) surface water quality, (2) impacts to wildlife, (3) number of receiving waters with potential human health cancer risks, (4) number of receiving waters with potential to cause non-cancer human health effects, and (5) nutrient impacts.

The EPA focused its quantitative analyses on the changes in environmental and human health impacts associated with exposure to toxic bioaccumulative pollutants via the surface water pathway. The EPA modeled changes in discharges of toxic, bioaccumulative pollutants from both FGD wastewater and BA transport water into rivers and streams and lakes and ponds, including reservoirs. The EPA addressed environmental impacts from nutrients in a separate analysis discussed in Section XII of this preamble.

The environmental assessment concentrates on impacts to aquatic life based on changes in surface water quality; impacts to aquatic life based on changes in sediment quality within surface waters; impacts to wildlife from consumption of contaminated aquatic organisms; and impacts to human health from consumption of contaminated fish and water. The Supplemental EA discusses, with quantified results, the estimated environmental changes projected within the immediate receiving waters due to the estimated pollutant loading changes associated with the regulatory options in today's proposal compared to the 2015 rule. All of the modeled changes are small in magnitude.

XII. Benefits Analysis

This section summarizes the EPA's estimates of the changes in national environmental benefits expected to result from potential changes in steam electric facility wastewater discharges described in Section IX of this preamble, and the resultant environmental effects, summarized in Section XI. The Benefit Cost Analysis (BCA) report provides additional details on the benefits methodologies and analyses, including uncertainties and limitations. The analysis methodology for quantified benefits is generally the same as that used by the EPA for the 2015 rule, but with revised inputs and assumptions that reflect updated data. The EPA has updated the methodology from the Stage 2 Disinfection Byproduct Rule for estimating benefits of reducing bladder cancer incidence related to bromide discharges from steam electric facilities and associated brominated disinfection by-product formation at drinking water treatment facilities.

A. Categories of Benefits Analyzed

Table XII-1 summarizes benefit categories associated with the proposed regulatory options and notes which categories the EPA was able to quantify and monetize. Analyzed benefits fall into six broad categories: human health benefits from surface water quality improvements, ecological conditions and effects on recreational use from surface water quality changes, market and productivity benefits, air-related effects, and changes in water withdrawal. Within these broad categories, the EPA was able to assess changes in the benefits projected for the regulatory options in today's proposal with varying degrees of completeness and rigor. Where possible, the EPA quantified the expected changes in effects and estimated monetary values. However, data limitations, modeling limitations, and gaps in the understanding of how society values certain environmental changes prevent the EPA from quantifying and/or monetizing some benefit categories. In the following discussion, positive benefit values represent improvements in environmental conditions and negative values represent forgone benefits of the proposed options compared to the baseline.

Table XII-1. Summary of Benefits Categories Associated with Changes in Pollutant Discharges from Steam Electric Facilities

Benefit category	Quantified and monetized	Quantified but not monetized	Neither quantified nor monetized
Human Health Benefits from Surface Water Quality Changes			
Changes in incidence of bladder cancer from exposure to total trihalomethanes (TTHM) in drinking water.	✓		
Changes in incidence of cancer from arsenic exposure via fish consumption.	✓		
Changes in incidence of cardiovascular disease from lead exposure via fish consumption.			✓
Changes in incidence of other cancer and non-cancer adverse health effects (e.g., reproductive, immunological, neurological, circulatory, or respiratory toxicity) due to exposure to arsenic, lead, cadmium, and other toxics from fish consumption or drinking water.		✓	✓
Changes in IQ loss in children from lead exposure via fish consumption.	✓		
Changes in need for specialized education for children from lead exposure via fish consumption.	✓		
Changes in *in utero* mercury exposure via maternal fish consumption.	✓		
Changes in health hazards from exposure to pollutants in waters used recreationally (e.g., swimming).			✓
Ecological Conditions and Effects on Recreational Use from Surface Water Quality Changes			
Benefits from changes in surface water quality, including: aquatic and wildlife habitat; water-based recreation, including fishing, swimming, boating, and nearwater activities; aesthetic benefits, such as enhancement of adjoining site amenities (e.g., residing, working, traveling, and owning property near the water[a]; and non-use value (existence, option, and bequest value from improved ecosystem health).[a]	✓		
Benefits from protection of threatened and endangered species.		✓	
Changes in sediment contamination.			✓

Benefit category	Quantified and monetized	Quantified but not monetized	Neither quantified nor monetized
Market and Productivity Benefits			
Changes in impoundment failures.			✓
Changes in water treatment costs for municipal drinking water, irrigation water, and industrial process.			✓
Changes in commercial fisheries yields.			✓
Changes in tourism and participation in water-based recreation.			✓
Changes in property values from water quality changes.			✓
Changes in ability to market coal combustion byproducts.			✓
Changes in maintenance dredging of navigational waterways and reservoirs due to changes in sediment discharges.	✓		
Air-Related Effects			
Human health benefits from changes in morbidity and mortality from exposure to NO_X, SO_2 and particulate matter (PM2.5).		✓	
Avoided climate change impacts from CO_2 emissions.	✓		
Changes in Water Withdrawal			
Changes in the availability of groundwater resources.	✓		
Changes in impingement and entrainment of aquatic organisms.			✓
Changes in susceptibility to drought.			✓

[a.] These values are implicit in the total willingness-to-pay (WTP) for water quality improvements.

The following section summarizes the EPA's analysis of the benefit categories that the Agency was able to quantify and/or monetize (identified in the second and third columns of Table XII-1, respectively). Benefits are a function of not only the changes in pollutant loadings under the various options, but also the timing of those options. For example, although loadings increase more under Option 1, treatment technologies are in place sooner, resulting in fewer forgone lead, mercury, and arsenic-related human health benefits under Option 1 than under more stringent options that may be installed in the future. The regulatory options would also affect additional benefit categories that the Agency was not able to monetize. The BCA Report further describes some of these additional nonmonetized benefits.

B. Quantification and Monetization of Benefits

1. Changes in Human Health Benefits from Changes in Surface Water Quality

Changes in pollutant discharges from steam electric facilities affect human health benefits in multiple ways. Exposure to pollutants in steam electric power facility discharges via consumption of fish from affected waters can cause a wide variety of adverse health effects, including cancer, kidney damage, nervous system damage, fatigue, irritability, liver damage, circulatory damage, vomiting, diarrhea, brain damage, IQ loss, and many others. Exposure to drinking water containing brominated disinfection by-products could cause adverse health effects such as cancer and reproductive and fetal development issues. Because the regulatory options in this proposal would change discharges of steam electric pollutants into waterbodies that receive or are downstream from these discharges, they may alter incidence of associated illnesses, even if by small amounts. These analyses, which are detailed in Chapters 4 and 5 of the BCA, find that the incremental changes in exposure between the baseline and regulatory options are minimal compared to the absolute changes for those same pollutants evaluated in the 2015 rule.

Due to data limitations and uncertainties, the EPA is able to monetize only a subset of the changes in health benefits associated with changes in pollutant discharges from steam electric facilities resulting from the regulatory options in this proposal as compared to the baseline. The EPA monetized these changes in human health effects by estimating the change in the expected number of individuals experiencing adverse human health effects in the populations exposed to steam electric discharges and/or altered exposure levels for the regulatory options relative to the baseline, and valuing these changes using different monetization methods for different benefit endpoints.

The EPA estimated changes in health risks from the consumption of contaminated fish from waterbodies within 50 miles of households. The EPA used Census Block population data and state-specific average fishing rates to estimate the exposed population. The EPA used cohort-specific fish consumption rates and waterbody-specific fish tissue concentration estimates to calculate potential exposure to steam electric pollutants. Cohorts were defined by age, sex, race/ ethnicity, and fishing mode (recreational or subsistence). The EPA used these data to quantify and monetize changes in the following five categories of human health effects, which are further detailed in the BCA Report:

- Changes in IQ Loss in Children Aged Zero to Seven from Lead Exposure via Fish Consumption.
- Changes in Need for Specialized Education for Children from Lead Exposure via Fish Consumption.
- Changes in In Utero Mercury Exposure via Maternal Fish Consumption and Associated IQ Loss.
- Changes in Incidence of Cancer from Arsenic Exposure via Fish Consumption.

Table XII-2 summarizes the monetary value of changes in all estimated health outcomes associated with consumption of contaminated fish tissue for the ELG options compared to the baseline. Chapter 5 of the BCA provides additional detail on the methodology. The EPA solicits comment on the assumptions and uncertainties included in this analysis.

Table XII-2. Estimated Total Monetary Values of Changes in Human Health Outcomes for ELG Options (millions of 2018$) Compared to Baseline[a]

Discount Rate	Option	Reduced Lead Exposure for Children[b]	Reduced Mercury Exposure for Children	Reduced Cancer Cases from Arsenic	Total
3%	1	$0.00	-$0.31	$0.00	-$0.31
	2	-$0.01	-$2.84	$0.00	-$2.85
	3	$0.00	-$2.85	$0.00	-$2.85
	4	$0.00	-$1.49	$0.00	-$1.49

Discount Rate	Option	Reduced Lead Exposure for Children[b]	Reduced Mercury Exposure for Children	Reduced Cancer Cases from Arsenic	Total
7%	1	$0.00	-$0.06	$0.00	-$0.06
	2	$0.00	-$0.57	$0.00	-$0.575
	3	$0.00	-$0.58	$0.00	-$0.58
	4	$0.00	-$0.30	$0.00	-$0.30

a. Negative values represent forgone benefits.

b. "$0.00" indicates that monetary values are greater than -$0.01 million but less than $0.00 million. Benefits to children from exposure to lead range from -$9.1 to $0.7 thousands per year, using a 3 percent discount rate, and from -$2.1 to $0.2 thousands, using a 7 percent discount rate.

The EPA also estimated changes in bladder cancer incidence from the use and consumption of drinking water contaminated with total trihalomethanes (TTHMs) derived from changes in pollutant loadings of bromide associated with the four regulatory options in today's proposal relative to the baseline. This qualitative relationship between bladder cancer and bromide demonstrates the relative size of the benefit to other benefits associated with this proposal. Should this analysis be used to justify an economically significant rulemaking, the EPA intends to peer review the analysis consistent with OMB's Information Quality Bulletin for Peer Review. That review would include robust examination of the strengths and limitations of the methods and an exploration of the sensitivity of the results to the assumptions made. If the analysis is designated a highly influential scientific assessment (HISA), one way the EPA may seek such a review is via the EPA's Science Advisory Board (SAB), which is particularly well suited to provide a peer review of HISAs. The EPA's SAB is a statutorily established committee with a broad mandate to provide advice and recommendations to the Agency on scientific and technical matters.

The EPA estimated changes in cancer risks within populations served by drinking water treatment facilities with intakes on surface waters influenced by bromide discharges from steam electric facilities. The EPA used Safe Drinking Water Information System (SDWIS) and US

Census data to estimate the exposed population. The EPA used estimates of changes in waterbody-specific bromide concentrations and estimates of drinking water treatment facility-specific TTHM concentrations to calculate potential changes in exposure to TTHM and associated adverse health outcomes.

The TTHM MCL is set higher than the health-based trihalomethane Maximum Contaminant Level Goals (MCLGs) in order to balance protection from human health risks from DBP exposure with the need for adequate disinfection to control human health risks from microbial pathogens. Actions that reduce TTHM levels below the MCL can therefore further reduce human health risk. The EPA's analysis quantifies the human health effects associated with incremental changes between the MCL and the MCLG. Recent TTHM compliance monitoring data indicate that the drinking water treatment facilities contributing most significantly to the total estimated benefits for the regulatory options have TTHM levels below the MCL but in excess of the MCLGs for trihalomethanes.

Table XII–3 summarizes the estimated monetary value of estimated changes in bromide-related human health outcomes from modeled surface water quality improvements under Options 2, 3, and 4 or degradation under Option 1. As described in Chapter 4 of the BCA Report, approximately 90 percent of these benefits derive from a small number of steam electric facilities (6 facilities under Option 2, 7 facilities under Option 3, and 17 facilities under Option 4). Bromide reduction benefits under Options 2 and 3 derive from estimated facility participation in the VIP.

The formation of TTHM in a particular water treatment system is a function of several site-specific factors, including chlorine, bromine, organic carbon, temperature, pH and the system residence time. The EPA did not collect site-specific information on these factors at each potentially affected drinking water treatment facility. Instead, the EPA conducted a site-based analysis which only addresses the estimated site-specific changes in bromides. To account for the changes in TTHM, and subsequently bladder cancer incidence, using only the estimated site-specific changes in bromides, the EPA used the national relationship from Regli et al (2015).[93] Using this relationship the analysis held all of the other site-specific factors constant at the measured values at the approximately 200 drinking water treatment facilities in that study. Thus, while the national changes in TTHM and bladder cancer incidence given estimated changes in bromide are the EPA's best estimate on a nationwide basis, the EPA cautions that for any specific drinking water treatment facility the estimates could be over- or underestimated. The EPA solicits comment on the extent to which uncertainty surrounding site-specific estimated benefits associated with bromides reductions impact the national estimates presented in this analysis, as well as data that would assist the EPA in evaluating this uncertainty. Additional details and uncertainties of this analysis are provided in Chapter 4 of the BCA Report.

Table XII-3. Estimated Human Health Benefits of Changing Bromide Discharges under the ELG Options Compared to Baseline (Million of 2018$, three and seven percent discount rate)

Regulatory Option	Annualized Human Health Benefits Over 27 Years (Millions of 2018$, discounted to 2020) [a]	
	3% Discount Rate	7% Discount Rate
Option 1	-$0.36	-$0.23
Option 2	$37.61	$24.21
Option 3	$42.57	$27.48
Option 4	$84.32	$54.30

[a.] The analysis accounts for the persisting health effects (up until 2121) from changes in TTHM exposure during the period of analysis (2021-2047).

2. Changes in Surface Water Quality

[93] Regli, S., Chen, J., Messner, M., Elovitz, M. S., Letkiewicz, F. J., Pegram, R. A., Pepping, T.J., Richardson, S.D., Wright, J. M., 2015. Estimating potential increased bladder cancer risk due to increased bromide concentrations in sources of disinfected drinking waters. Environmental Science & Technology, 49(22), 13094-13102.

The EPA evaluated whether the regulatory options in today's proposal would alter aquatic habitats and human welfare by changing concentrations of harmful pollutants such as arsenic, cadmium, chromium, copper, lead, mercury, nickel, selenium, zinc, nitrogen, phosphorus, and suspended sediment relative to the baseline. As a result, the usability of some of the waters for recreation relative to baseline discharge conditions could change under each option, thereby affecting recreational users. Changes in pollutant loadings can also change the attractiveness of waters usable for recreation by making recreational trips more or less enjoyable. The regulatory options may also change nonuse values stemming from bequest, altruism, and existence motivations. Individuals may value water quality maintenance, ecosystem protection, and healthy species populations independent of any use of those attributes.

The EPA uses a water quality index (WQI) to translate water quality measurements, gathered for multiple parameters that are indicative of various aspects of water quality, into a single numerical indicator that reflects achievement of quality consistent with the suitability for certain uses. The WQI includes seven parameters: dissolved oxygen, biochemical oxygen demand, fecal coliform, total nitrogen, total phosphorus, TSS, and one aggregate subindex for toxics. The EPA modeled changes in four of these parameters, and held the remaining parameters (dissolved oxygen, biochemical oxygen demand, and fecal coliform) constant for the purposes of this analysis. Table XII-4 summarizes water quality change ranges relative to the baseline under the four regulatory options. Under Options 1 through 3, 78 to 84 percent of potentially affected reaches have a negative change in the WQI. Another 16 to 22 percent of reaches show no change under these options. Under Option 4, 61 percent of reaches would experience a negative change in the WQI, and another 12 percent of reaches show no change.

Table XII-4. Estimated Ranges of Water Quality Changes under Regulatory Options Compared to Baseline

Regulatory Option	Minimum ΔWQI[a]	Maximum ΔWQI	Median ΔWQI	ΔWQI Interquartile Range
Option 1	-5.29	0.00	-0.00102	0.01000
Option 2	-2.95	1.30	-0.00047	0.00168
Option 3	-2.95	1.30	-0.00023	0.00078
Option 4	-2.62	1.31	-0.00002	0.00125

[a.] Negative changes in WQI values indicate degrading water quality.

The EPA estimated the change in monetized benefit values using the same meta-regressions of surface water valuation studies used in the benefit analysis for the 2015 rule. The meta-regressions quantify average household WTP for incremental improvements in surface water quality. This WTP is the maximum amount of money a person is willing to give up to obtain an improvement in water quality. Chapter 6 of the BCA provides additional detail on the valuation methodology. Overall, Option 1 results in water quality degradation, which is reflected in negative annual household WTP values ranging from -$0.11 to -$0.62. Under Options 2, 3, and 4, the net water quality improvements (accounting for all increases and decreases of pollutant loadings) result in positive net benefits to households affected by water quality changes from the regulatory options proposed. The estimated annual household WTP for water quality changes ranges from $0.10 to $0.56 for Option 2, $0.16 to $0.87 for Option 3, and $0.19 to $1.04 for Option 4.

Table XII-5 presents annualized total WTP values for water quality changes associated with modified metal (arsenic, cadmium, chromium, copper, lead, mercury, zinc, and nickel), non-metal (selenium), nutrient (phosphorus and nitrogen), and sediment pollutant discharges to the approximately 10,393 reach miles affected by the regulatory options in this proposal. An estimated 85 million households reside in Census block groups within 100 miles of affected reaches. The central tendency estimate of the total annualized benefits of water quality changes for Option 2 range from $14.3 million (7 percent discount rate) to $16.7 million (3 percent discount rate).

Table XII-5. Estimated Total Willingness-to-Pay for Water Quality Changes (Millions 2018$) Compared to Baseline[a]

Regulatory Option	Number of Affected Households (Millions)	3% Discount Rate			7% Discount Rate		
		Low	Central	High	Low	Central	High
Option 1	85.2	-$10.0	-$12.5	-$55.5	-$8.6	-$10.9	-$48.1
Option 2	86.9	$11.8	$16.7	$65.6	$10.1	$14.3	$56.1
Option 3	84.6	$16.3	$22.5	$90.7	$14.0	$19.4	$77.8
Option 4	86.5	$19.8	$27.3	$110.2	$17.0	$23.6	$94.6

[a.] Negative values represent forgone benefits and positive values represent realized benefits.

3. Effects on Threatened and Endangered Species

To assess the potential for impacts on T&E species (both aquatic and terrestrial) relative to the 2015 baseline, the EPA analyzed the overlap between waters expected to change their wildlife WQC exceedance status under a particular option and the known critical habitat locations of high-vulnerability T&E species. The EPA examined the life history traits of potentially affected T&E species and categorized them by potential for population impacts due to surface water quality changes. Chapter 7 of the BCA Report provides additional detail on the methodology. The EPA determined that there are 24 species whose known critical habitat overlaps with surface waters that may be affected by the proposed options when compared to the baseline, including three fish species, two amphibian and reptile species, one bird species, 17 clam and mussel species, and one snail species. Six of these species have known critical habitat overlapping surface waters that are expected to see reduced exceedances of NRWQC under proposed Options 2, 3, or 4, while 23 species (including 5 species that may see reduced exceedances of NRWQC under proposed Options 2, 3, or 4, depending on habitat location) have known critical habitat overlapping surface waters that may see increased exceedances of

NRWQC under one or more of the proposed options. Under Option 2, there are two species whose known critical habitat overlaps with surface waters that may see reduced exceedances of NRWQC, and 12 species whose known critical habitat overlaps with surface waters that may see increased exceedances of NRWQC. Option 1 is expected to result in increased exceedances of NRWQC across all habitat locations. Principal sources of uncertainty include the specifics of how these proposed options will impact threatened and endangered species, exact spatial distribution of the species, and additional species of concern not considered.

4. Changes in Benefits from Marketing of Coal Combustion Residuals

The proposed rule options could affect the ability of steam electric facilities to market coal combustion byproducts for beneficial use by converting from wet to dry handling of BA. In particular, the EPA evaluated the potential effects from changes in marketability of BA as a substitute for sand and gravel in fill applications. Among the regulatory options considered for this proposal, EPA estimates that only Option 2 would affect the quantity of BA handled wet when compared to the baseline, and for that option the estimated increase in BA handled wet is small (total of 310,671 tons per year at 20 facilities). Given these small changes and the uncertainty associated with projecting facility-specific changes in marketed ash, the EPA chose not to monetize this benefit category in the analysis of the proposed regulatory options. *See* Chapter 2 in the BCA report for additional details.

5. Changes in Dredging Costs

The proposed regulatory options would affect discharge loadings of various categories of pollutants, including TSS, thereby changing the rate of sediment deposition to affected waterbodies, including navigable waterways and reservoirs that require dredging for maintenance.

Navigable waterways, including rivers, lakes, bays, shipping channels and harbors, are an integral part of the United States transportation network. They are prone to reduced functionality due to sediment build-up, which can reduce the navigable depth and width of the waterway. In many cases, costly periodic dredging is necessary to keep them passable. Reservoirs serve many functions, including storage of drinking and irrigation water supplies, flood control, hydropower supply, and recreation. Streams can carry sediment into reservoirs, where it can settle and cause buildup of silt layers over time. Sedimentation reduces reservoir capacity and the useful life of reservoirs unless measures such as dredging are taken to reclaim capacity. Chapter 10 of the BCA provides additional detail on the methodology.

The EPA expects that Option 4 would provide cost savings ranging from \$0.48 million (7 percent discount rate) to \$0.72 million (3 percent discount rate) by reducing required dredging maintenance for both navigable waterways and reservoirs. Estimated increases in sediment loadings under Options 1, 2, and 3 would result in cost increases. Cost increases range from \$0.05 million to \$0.09 million for Option 1, \$0.12 million to \$0.21 million for Option 2, and \$0.04 million to \$0.07 million for Option 3.

6. Changes in Air-Related Effects

The EPA expects the proposed options to affect air pollution through three main mechanisms: (1) changes in auxiliary electricity use by steam electric facilities to operate wastewater treatment, ash handling, and other systems that the EPA predicts facilities would use under each proposed option; (2) changes in transportation-related air emissions due to changes in trucking of CCR waste to landfills; and (3) change in the profile of electricity generation due to the relatively higher or lower costs to generate electricity at steam electric facilities incurring compliance costs under the proposed options.

Changes in the electricity generation profile can increase or decrease air pollutant emissions because emission factors vary for different types of electric boilers. For this analysis, the changes in air emissions are based on the change in dispatch of generation units as projected by IPM V6 given the overlaying of costs for complying with the proposed options onto steam electric boilers' production costs. As discussed in Section VIII of this preamble, the IPM V6 analysis accounts for the effects of other regulations on the electric power sector.

The EPA evaluated potential effects resulting from net changes in air emissions of three pollutants: NO_X, SO_2, and CO_2. NO_X and SO_X are precursors to fine particles sized 2.5 microns and smaller ($PM_{2.5}$), this air pollutant causes a variety of adverse health effects including premature death, non-fatal heart attacks, hospital admissions, emergency department visits, upper and lower respiratory symptoms, acute bronchitis, aggravated asthma, lost work days, and acute respiratory symptoms. CO_2 is a key greenhouse gas linked to a wide range of domestic effects.[94]

The EPA used domestic social cost of carbon estimates to value changes in CO_2 emissions (SC- CO_2). The Agency quantified changes in emissions of $PM_{2.5}$ precursors, NO_X, and SO_2. To map those emission changes to air quality changes across the country, air quality modeling is needed. Prior to this proposal, the EPA's modeling capacity was fully allocated to supporting other regulatory and policy efforts.

Table XII-6 shows the changes in emissions of NO_X, SO_2, and CO_2 based on the estimated increases in electricity generation (see Table VIII-3) for options 2 and 4 (the two regulatory options that the EPA analyzed for these increased emission effects). Table XII-7 shows the total annualized monetary values associated with changes in emissions of CO_2 for

[94] U.S. EPA. Integrated Science Assessment (ISA) for Particulate Matter (Final Report, Dec 2009). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F, 2009.

options 2 and 4. All total monetary values are negative, indicating that the proposed rule results in net forgone CO_2-related benefits when compared to the baseline. While not monetized, additional forgone benefits associated with $PM_{2.5}$ would also occur. The majority of the forgone benefits are due to changes in the profile of electricity generation. Smaller shares of the changes in total benefits are attributable to changes in energy use to operate wastewater treatment systems. Benefits from changes in trucking emissions are negligible. The EPA did not analyze benefits from changes in air emissions for Options 1 and 3 but instead extrapolated values by scaling air-related benefits under Option 2 in proportion to the total social costs of each option. Chapter 8 of the BCA Report provides additional details on the analysis of air-related benefits.

Table XII-6. Estimated Changes in Air Emissions Compared to Baseline[a]

Regulatory Option	Category of Emissions	CO_2 (Metric Tonnes/Year)	NO_X (Tons/Year)	SO_2 (Tons/Year)
Option 2	Electricity generation[b,c]	5,656,000	4,650	4,930
	Trucking	-490	0	0
	Energy use[b,c]	-44,080	-32	-54
	Total[d]	**5,611,000**	**4,620**	**4,870**
Option 4	Electricity generation[b,e]	1,244,000	1,900	1,020
	Trucking	1,440	1	0
	Energy use[b,e]	59,320	31	20
	Total[d]	**1,305,000**	**1,940**	**1,040**

a. Negative values represent emission reductions.

b. Estimated changes in emissions shown for 2028-2032 based on the estimated increase in electricity generation of 0.3% for Option 2 and 0.1% for Option 4.

c. Option 2 estimates are based on the IPM sensitivity analysis scenario that includes the ACE rule in the baseline (IPM-ACE).

d. Values may not sum to the total due to independent rounding.

e. Option 4 estimates are based on IPM analysis scenario that does not include the ACE rule in the baseline.

Table XII-7. Estimated Annualized Benefits from Changes in CO_2 Air Emissions (Millions; 2018$) Compared to Baseline[a]

Regulatory Option	Category of Emissions	3% Discount Rate	7% Discount Rate
Option 2	Electricity generation[b]	-$32.0	-$5.2
	Trucking	$0.0	$0.0

	Energy use[b]	$0.4	$0.1
	Total[c]	**-$31.6**	**-$5.2**
Option 4	Electricity generation[d]	-$4.3	-$0.8
	Trucking	$0.0	$0.0
	Energy use[d]	-$0.5	$0.0
	Total[c]	**-$4.8**	**-$0.9**

[a.] Negative values represent forgone benefits.

[b.] Option 2 estimates are based on the IPM sensitivity analysis scenario that includes the ACE rule in the baseline (IPM-ACE).

[c.] Values may not sum to the total due to independent rounding.

[d.] Option 4 estimates are based on IPM analysis scenario that does not include the ACE rule in the baseline.

7. Benefits from Changes in Water Withdrawals

Steam electric facilities use water for handling BA and operating wet FGD scrubbers. By reducing water used in sluicing operations or prompting the recycling of water in FGD wastewater treatment systems, Option 4 is expected to reduce water withdrawals from surface waters, whereas proposed Options 1, 2, and 3 are expected to increase water withdrawals from surface waterbodies. Option 2 is also expected to increase water withdrawal from aquifers. Using the same methodology used for the 2015 rule, the EPA estimated the monetary value of increased ground water withdrawals based on increased costs of ground water supply. For each relevant facility, the EPA multiplied the increase in ground water withdrawal (in gallons per year) by water costs of about $1,192 per acre-foot. Chapter 9 of the BCA Report provides the details of this analysis. The EPA estimates the changes in annualized benefits of increased ground water withdrawals are less than $0.2 million annually. Due to data limitations, the EPA was not able to estimate the monetary value of changes in surface water withdrawals. Chapter 9 of the BCA Report and Section 7 of the Supplemental TDD provide additional details on the estimated changes in surface water withdrawals.

C. Total Monetized Benefits

Using the analysis approach described above, the EPA estimated the total monetary value of annual benefits of the proposed rule for all monetized categories. Table XII-8 and Table XII-9 summarize the total annualized monetary value of social welfare effects using 3 percent and 7 percent discount rates, respectively. The total monetary value of benefits under Option 2 range from $14.8 million to $68.5 million using a 3 percent discount rate and from $28.4 million to $74.4 million using a 7 percent discount rate.

Table XII-8. Summary of Total Annualized Benefits at 3 Percent (Millions; 2018$)[a]

Benefit Category	Option 1			Option 2			Option 3			Option 4		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Human Health[d]		**-$0.7**			**$34.8**			**$39.7**			**$82.8**	
Changes in IQ losses in children from exposure to lead[b]		<$0.0			<$0.0			<$0.0			<$0.0	
Changes in IQ losses in children from exposure to mercury		-$0.3			-$2.84			-$2.85			-$1.49	
Reduced cancer risk from DBPs in drinking water		-$0.4			$37.6			$42.6			$84.3	
Ecological Conditions and Recreational Uses Changes	**-$10.0**	**-$12.5**	**-$55.5**	**$11.8**	**$16.7**	**$65.6**	**$16.3**	**$22.5**	**$90.7**	**$19.8**	**$27.3**	**$110.2**
Use and nonuse values for water quality changes	-$10.0	-$12.5	-$55.5	$11.8	$16.7	$65.6	$16.3	$22.5	$90.7	$19.8	$27.3	$110.2
Market and Productivity[d]	**-$0.1**	**-$0.1**	**-$0.1**	**-$0.2**	**-$0.2**	**-$0.2**	**-$0.1**	**-$0.1**	**-$0.1**	**$0.6**	**$0.6**	**$0.7**
Changes in dredging costs	-$0.1	-$0.1	-$0.1	-$0.1	-$0.2	-$0.2	-$0.1	-$0.1	-$0.1	$0.6	$0.6	$0.7
Reduced water withdrawals[b]		$0.0			<$0.0			$0.0			$0.0	
Air-related effects		**-$30.3**			**-$31.6**			**-$20.9**			**-$4.8**	
Changes in CO_2 air emissions[c]		-$30.3			-$31.6			-$20.9			-$4.8	
Total[d]	**-$41.0**	**-$43.6**	**-$86.6**	**$14.8**	**$19.6**	**$68.5**	**$35.1**	**$41.3**	**$109.4**	**$98.4**	**$105.9**	**$188.9**

a. Negative values represent forgone benefits and positive values represent realized benefits.

b. "<$0.0" indicates that monetary values are greater than -$0.1 million but less than $0.00 million.

c. The EPA estimated the air-related benefits for Option 2 using the IPM sensitivity analysis scenario that includes the ACE rule in the baseline (IPM-ACE). EPA extrapolated estimates for Options 1 and 3 air-related benefits from the estimate for Option 2 that is based on IPM-ACE outputs. The values for Option 4 air-related benefits were estimated using the IPM analysis scenario that does not include the ACE rule in the baseline.

d. Values for individual benefit categories may not sum to the total due to independent rounding.

Table XII-9. Summary of Total Annualized Benefits at 7 Percent (Millions; 2018$)[a]

Benefit Category	Option 1			Option 2			Option 3			Option 4		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Human Health[d]		**-$0.3**			**$23.6**			**$26.9**			**$54.0**	
Changes in IQ losses in children from exposure to lead[b]		<$0.0			<$0.0			<$0.0			<$0.0	
Changes in IQ losses in children from exposure to mercury		-$0.1			-$0.6			-$0.6			-$0.3	
Reduced cancer risk from DBPs in drinking water		-$0.2			$24.2			$27.5			$54.3	
Ecological Conditions and Recreational Uses Changes	**-$8.6**	**-$10.9**	**-$48.1**	**$10.1**	**$14.3**	**$56.1**	**$14.0**	**$19.4**	**$77.8**	**$17.0**	**$23.6**	**$94.6**
Use and nonuse values for water quality changes	-$8.6	-$10.9	-$48.1	$10.1	$14.3	$56.1	$14.0	$19.4	$77.8	$17.0	$23.6	$94.6
Market and Productivity[d]	**-$0.1**	**-$0.1**	**-$0.1**	**-$0.1**	**-$0.2**	**-$0.2**	**$0.0**	**-$0.1**	**-$0.1**	**$0.5**	**$0.5**	**$0.7**
Changes in dredging costs	-$0.1	-$0.1	-$0.1	-$0.1	-$0.1	-$0.2	$0.0	-$0.1	-$0.1	$0.5	$0.5	$0.7
Reduced water withdrawals[b]		$0.0			<$0.0			$0.0			$0.0	
Air-related Effects		**-$4.8**			**-$5.2**			**-$3.7**			**-$0.9**	
Changes in CO_2 air emissions[c]		-$4.8			-$5.2			-$3.7			-$0.9	
Total[d]	**-$13.7**	**-$16.0**	**-$53.3**	**$28.4**	**$32.6**	**$74.4**	**$37.1**	**$42.5**	**$100.9**	**$70.6**	**$77.2**	**$148.4**

a. Negative values represent forgone benefits and positive values represent realized benefits.

b. "<$0.0" indicates that monetary values are greater than -$0.1 million but less than $0.00 million.

c. The EPA estimated the air-related benefits for Option 2 using the IPM sensitivity analysis scenario that includes the ACE rule in the baseline (IPM-ACE). EPA extrapolated estimates for Options 1 and 3 air-related benefits from the estimate for Option 2 that is based on IPM-ACE outputs. The values for Option 4 air-related benefits were estimated using the IPM analysis scenario that does not include the ACE rule in the baseline.

d. Values for individual benefit categories may not sum to the total due to independent rounding.

D. Unmonetized Benefits

The monetary value of the proposed rule's effects on social welfare does not account for all effects of the proposed options because, as described above, the EPA is unable to monetize some categories. Examples of effects not reflected in these monetary estimates include health and other effects from changes in NO_X and SO_2 air emissions; changes in certain non-cancer 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 BCA Report discusses changes in these effects qualitatively, indicating their potential magnitude where possible.

XIII. Development of Effluent Limitations and Standards

A. FGD Wastewater

The proposed rule contains new numeric effluent limitations and pretreatment standards that apply to discharges of FGD wastewater at existing sources.[95] The EPA is proposing several sets of effluent limitations and pretreatment standards for FGD wastewater discharges; the specific set of limitations that would apply to any particular facility are determined by which subcategory the facility falls within, or whether it chooses to participate in the voluntary incentives program. The EPA developed the numeric effluent limitations and pretreatment standards in this proposed rule using long-term average effluent values and variability factors that account for variations in performance at well-operated facilities that employ the technologies that constitute the bases for control. The EPA's methodology for derivation of limitations in ELGs is longstanding and has been upheld in court. *See*, e.g., *Chem. Mfrs. Ass'n v. EPA*, 870

[95] Effluent limitations for boilers with nameplate capacity of 50 MW or smaller and for boilers that will retire by December 31, 2028, are not discussed in this section. The proposed limitations for these generating units are based on the previously established BPT limitations on TSS.

F.2d 177 (5th Cir. 1989); Nat'l Wildlife Fed'n v. EPA, 286 F.3d 554 (D.C. Cir. 2002). The EPA establishes the final effluent limitations and standards as "daily maximums" and "maximums for monthly averages." Definitions provided in 40 CFR 122.2 state that the daily maximum limitation is the "highest allowable 'daily discharge'" and the maximum for monthly average limitation is the "highest allowable average of 'daily discharges' over a calendar month, calculated as the sum of all 'daily discharges' measured during a calendar month divided by the number of 'daily discharges' measured during that month." Daily discharges are defined to be the "'discharge of a pollutant' measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling."

1. Overview of the Limitations and Standards

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 achieve the long-term average 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). The EPA recognizes that variability around the long-term average occurs during normal operations. This variability means that facilities occasionally may discharge at a level that is higher than the long-term average, and at other times will discharge at a level that is lower than the long-term average. To allow for these possibly higher daily discharges and provide an upper bound for the allowable concentration of pollutants that may be discharged, while still targeting achievement of the long-term average, the EPA has established the daily maximum limitation. A facility consistently discharging at a level near the daily maximum limitation would be symptomatic of a facility that is <u>not</u> operating its treatment to achieve the long-term average. 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 and may result in values that periodically exceed the limitations due to routine variability in treated effluent.

The EPA's objective in establishing monthly average limitations is to provide an additional restriction to help ensure that facilities target their average discharges to achieve the long-term average. The monthly average limitation requires dischargers to provide ongoing control, on a monthly basis, that supplements controls imposed by the daily maximum limitation. In order to meet the monthly average limitation, a facility must counterbalance a value near the daily maximum limitation with one or more values well below the daily maximum limitation.

2. Criteria Used to Select Data

In developing effluent limitations guidelines and standards for any industry, the EPA qualitatively reviews all the data before selecting data that represents proper operation of the technology that forms the basis for the limitations. The EPA typically uses four criteria to assess the data. The first criterion requires that the facilities have the model treatment technology identified as a candidate basis for effluent limitations (e.g., chemical precipitation with LRTR) and demonstrate consistently diligent and optimal operation. Application of this criterion typically eliminates any facility with treatment other than the model technology. The EPA generally determines whether a facility meets this criterion based upon site visits, discussions with facility management, and/or comparison to the characteristics, operation, and performance of treatment systems at other facilities. The EPA reviews available information to determine whether data submitted were representative of normal operating conditions for the facility and equipment. As a result of this review, the EPA typically excludes the data in developing the limitations when the facility has not optimized the performance of its treatment system.

A second criterion generally requires that the influents and effluents from the treatment components represent typical wastewater from the industry, without incompatible wastewater from other sources. Application of this criterion results in the EPA selecting those facilities where the commingled wastewaters did not result in substantial dilution, unequalized slug loads resulting in frequent upsets and/or overloads, more concentrated wastewaters, or wastewaters with different types of pollutants than those generated by the wastestream for which the EPA is proposing effluent limitations and pretreatment standards.

A third criterion typically ensures that the pollutants are present in the influent at sufficient concentrations to evaluate treatment effectiveness. If a data set for a pollutant shows that the pollutant was not present at a treatable concentration at sufficient frequency (e.g., the pollutant was below the level of detection in all influent samples), the EPA excludes the data for that pollutant at that facility when calculating the limitations.

A fourth criterion typically requires that the data are valid and appropriate for their intended use (e.g., the data must be analyzed with a sufficiently sensitive method). Also, the EPA does not use data associated with periods of treatment upsets because these data would not reflect the performance from well-designed and well-operated treatment systems. In applying the fourth criterion, the EPA may evaluate the pollutant concentrations, analytical methods and the associated quality control/quality assurance data, flow values, mass loading, facility logs, test reports, and other available information. As part of this evaluation, the EPA reviews the process or treatment conditions that may have resulted in extreme values (high and low). As a consequence of this review, the EPA may exclude data associated with certain time periods or other data outliers that reflect poor performance or analytical anomalies by an otherwise well-operated site.

The fourth criterion also is applied in the EPA's review of data corresponding to the initial commissioning period for treatment systems (and startup periods for pilot test equipment). Most industries incur commissioning periods during the adjustment period associated with installing new treatment systems. During this acclimation and optimization process, the effluent concentration values tend to be highly variable with occasional extreme values (high and low). This occurs because the treatment system typically requires some "tuning" as the facility staff and equipment and chemical vendors work to determine the optimum chemical addition locations and dosages, vessel hydraulic residence times, internal treatment system recycle flows (e.g., filter backwash frequency, duration and flow rate, return flows between treatment system components), and other operational conditions including clarifier sludge wasting protocols. It may also take time for treatment system operators to gain expertise on operating the new treatment system, which also contributes to treatment system variability during the commissioning period. After this initial adjustment period, the systems should operate at steady state with relatively low variability around a long-term average over many years. Because commissioning periods typically reflect one-time operating conditions unique to the first time the treatment system begins operation, the EPA generally excludes such data in developing the limitations.[96]

3. Data Used to Calculate Limitations and Standards

[96] Examples of conditions that are typically unique to the initial commissioning period include operator unfamiliarity or inexperience with the system and how to optimize its performance; wastewater flow rates that differ significantly from engineering design, altering hydraulic residence times, chemical contact times, and/or clarifier overflow rates, and potentially causing large changes in planned chemical dosage rates or the need to substitute alternative chemical additives; equipment malfunctions; fluctuating wastewater flow rates or other dynamic conditions (i.e., not steady state operation); and initial purging of contaminants associated with installation of the treatment system, such as initial leaching from coatings, adhesives, and susceptible metal components. These conditions differ from those associated with the restart of an already-commissioned treatment system, such as may occur from a treatment system that has undergone either short or extended duration shutdown.

The Supplemental TDD provides a description of the data and methodology used to develop long-term averages, variability factors, and limitations and standards for this proposed rule. The effluent limitations and pretreatment standards for the low utilization subcategory and high flow subcategory are based on chemical precipitation. The derivation of the limitations for these subcategories and the data used are described in Section 13 of the 2015 TDD. The new limitations and pretreatment standards proposed today for facilities not in those subcategories and for the voluntary incentives plan were derived from a statistical analysis of effluent data collected by facilities during extended testing of the LRTR technology and membrane filtration technology, respectively. The duration of the test programs at these facilities spanned from approximately one month for membranes to more than a year for LRTR, enabling the EPA to evaluate long-term performance of these technologies under conditions that can contribute to influent variability, including varying power demand, changes in coal suppliers, and changes in operation of the air pollution control system. The tests occurred over different seasons of the year and demonstrate that the technologies operate effectively under varying climate conditions.

During the development of these new limitations and pretreatment standards, the EPA identified certain data that warranted exclusion because: (1) the samples were analyzed using a method that is not sensitive enough to reliably quantify the pollutants present (e.g., use of EPA Method 245.1 to measure the concentration of mercury in effluent samples); (2) the analytical results were identified as questionable due to quality control issues associated with the laboratory analysis or sample collection, or were analytical anomalies; (3) the samples were collected prior to steady-state operating condition and do not represent BAT/PSES level of performance; (4) the samples were collected during a period where influent composition did not reflect the FGD wastewater (*e.g.*, untreated FGD wastewater was mixed with large volume of non-FGD wastewater prior to the treatment system); (5) the treatment system was operating in a manner that does not represent BAT/PSES level of performance; or (6) the samples were collected from a location that is not representative of treated effluent.

4. Long-Term Averages and Effluent Limitations and Standards for FGD Wastewater

Table XIV-1 presents the proposed effluent limitations and standards for FGD wastewater. For comparison, the table also presents the long-term average treatment performance calculated for each parameter. Due to routine variability in treated effluent, a power facility that targets discharging its wastewater at a level near the values of the daily maximum limitation or the monthly average limitation may periodically experience values exceeding the limitations. For this reason, the EPA recommends that facilities design and operate the treatment system to achieve the long-term average for the model technology. In doing so, a system that is designed and operated to achieve the BAT/PSES level of control would meet the limitations.

The EPA expects that facilities will be able to meet their effluent limitations or standards at all times. If an exceedance is caused by an upset condition, the facility would have an affirmative defense to an enforcement action if the requirements of 40 CFR 122.41(n) are met. Exceedances caused by a design or operational deficiency, however, are indications that the facility’s performance does not represent the appropriate level of control. For these proposed limitations and pretreatment standards, the EPA proposes to determine that such exceedances can be controlled by diligent process and wastewater treatment system operational practices, such as regular monitoring of influent and effluent wastewater characteristics and adjusting dosage rates for chemical additives to target effluent performance for regulated pollutants at the long-term average concentration for the BAT/PSES technology. Additionally, some facilities may need to upgrade or replace existing treatment systems to ensure that the treatment system is designed to achieve performance that targets the effluent concentrations at the long-term average. This is consistent with the EPA's costing approach and its engineering judgment, developed over years of evaluating wastewater treatment processes for steam electric facilities and other industrial sectors. The EPA recognizes that some dischargers, including those that are operating technologies representing the technology basis for the proposed rule, may need to improve their treatment systems, process controls, and/or treatment system operations in order to consistently meet the proposed 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.

See Section 8 of the Supplemental TDD for more information about the calculation of the limitations and pretreatment standards presented in the tables below.

Table XIV-1. Long-Term Averages and Effluent Limitations and Pretreatment Standards for FGD Wastewater for Existing Sources (BAT/PSES)[a]

Subcategory	Pollutant	Long-Term Average	Daily Maximum Limitation	Monthly Average Limitation
Requirements for all facilities not in the VIP or subcategories specified below (BAT & PSES).	Arsenic (µg/L)	5.1	18	9
	Mercury (ng/L)	13.5	85	31
	Nitrate/nitrite as N (mg/L)	2.6	4.6	3.2
	Selenium (µg/L)	16.6	76	31
Voluntary Incentives Program for FGD Wastewater (BAT only).	Arsenic (µg/L)	5.0[b]	5[c]	---[d]
	Mercury (ng/L)	5.1	21	9
	Nitrate/nitrite as N (mg/L)	0.4	1.1	0.6
	Selenium (µg/L)	5.0	21	11
	Bromide (mg/L)	0.16	0.6	0.3
	TDS (mg/L)	88	351	156
Low utilization subcategory -AND- High flow subcategory (BAT & PSES).	Arsenic (µg/L)	5.98	11	8
	Mercury (ng/L)	159	788	356

[a.] BAT effluent limitations for boilers with nameplate capacity of 50 MW or smaller, and boilers that will retire by December 31, 2028, are based on the previously established BPT limitations on TSS and are not shown in this table. The BAT effluent limitations for TSS for these retiring boilers is daily maximum of 100 mg/L; monthly average of 30 mg/L.

[b.] Long-term average is the arithmetic mean of the quantitation limitations since all observations were not detected.

[c.] Limitation is set equal to the quantitation limit for the data evaluated.

[d.] Monthly average limitation is not established when the daily maximum limitation is based on the quantitation limit.

The EPA notes that while some limitations are higher than corresponding limits in the 2015 rule, in other cases limitations of additional pollutants or lower limitations for pollutants regulated in the 2015 rule have also been calculated. The EPA solicits comment on the demonstrated ability or inability of existing systems to meet the limitations in this proposal, the costs associated with modifying existing systems or with modifying the operation of existing systems to meet these limits, and whether any existing systems with demonstrated issues meeting these limits would be best addressed through FDF variances or through subcategorization. Furthermore, should the EPA determine subcategorization of facilities with existing FGD treatment systems is warranted, the EPA solicits comment on what limitations should apply to those facilities, including whether the 2015 rule limits would be appropriate for such facilities.

B. BA Transport Water Limitations

1. Maximum 10 Percent 30-Day Rolling Average Purge Rate

In contrast to the limitations estimated for specific pollutants above, 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.[97] 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.[98] Since these calculations are only estimates, the EPA solicits data on actual precipitation and maintenance-related discharges. 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 by the volume of the system, and then averaged the resulting percent over 30 days.

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

[97] Although the technology basis includes dry handling, the limitation is based on the necessary purge volumes of a wet, high recycle rate BA system.

[98] Although presented in EPRI (2018), the EPA did not consider events such as pipe leaks, as these would not be reflective of proper system operation (*see* DCN SE06920).

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.[99]

Table XIV-2. 30-Day Rolling Average Discharge Volume as a Percent of System Volume[a]

Infrequent Discharge Needs as Estimated in EPRI (2018)		**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-System1**	**Facility F-System2**
		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.

The EPA recognizes that some facilities may need to improve their equipment, process controls, and/or operations to consistently meet the zero discharge standard established by the 2015 rule. However, with the discharge allowance included in this proposed rule, the EPA expects that facilities would be able to avoid these costs in most circumstances. For example, in the table above, 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. This is consistent with the CWA, which requires that BAT/PSES discharge limitations and standards reflect the best available technology economically achievable. For further discussion of costs associated with managing a fully-closed-loop system, *see* Section 5 of the Supplemental TDD.

2. Best Management Practices Plan

[99] 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.

As described in Section VII of this preamble, one of the regulatory options presented in today's proposed rule would require a subcategory of facilities discharging BA transport water and having low MWh production to develop and implement a BMP plan to recirculate BA transport water back to the BA handling system (*see* Section VII of this preamble for more details).

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 BA 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.[100] After determining the amount of BA transport water that could be easily recycled and developing a facility-specific BMP plan, facilities are required to implement the plan and annually review and revise the plan as necessary.

XIV. Regulatory Implementation

A. Implementation of the Limitations and Standards

The requirements in this rule apply to discharges from steam electric facilities through incorporation into NPDES permits issued by the EPA or by authorized states under Section 402 of the Act, and through local pretreatment programs under Section 307 of the Act. Permits or control mechanisms issued after this rule's effective date must incorporate the ELGs, as applicable. Also, under CWA section 510, states can require effluent limitations under state law as long as they are no less stringent than the requirements of this rule. Finally, in addition to

[100] 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.

requiring application of the technology-based ELGs in this rule, CWA section 301(b)(1)(C) requires the permitting authority to impose more stringent effluent limitations, as necessary, to meet applicable water quality standards.

1. Timing

The direct discharge limitations proposed in this rule would apply only when implemented in an NPDES permit issued to a discharger. Under the CWA, the permitting authority must incorporate these ELGs into NPDES permits as a floor or a minimum level of control. The proposed rule would allow a permitting authority to determine a date when the new effluent limitations for FGD wastewater and BA transport water will apply to a given discharger. As proposed, the permitting authority would make these effluent limitations applicable on or after November 1, 2020. For any final effluent limitation that is specified to become applicable after November 1, 2020, the specified date must be as soon as possible, but in no case later than December 31, 2023, for BA transport water, or December 31, 2025, for FGD wastewater. For dischargers choosing to meet the voluntary incentives program effluent limitations for FGD wastewater, the date for meeting those limitations is December 31, 2028.

For FGD wastewater and BA transport water from boilers retiring by 2028, the proposed BAT limitations would apply on the date that a permit is issued to a discharger. The proposed rule does not build in an implementation period for meeting these limitations, as the BAT limitation on TSS is equal to the previously promulgated BPT limitation on TSS. Pretreatment standards are self-implementing, meaning they apply directly, without the need for a permit. As defined by the statute, the pretreatment standards for existing sources must be met by three years after the effective date of any final rule.

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.

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, EPA recommends such a permit be reopened as soon as practicable, and modified consistent with any new rule provisions.

For permits that are issued on or after November 1, 2020, the permitting authority would determine the earliest possible date that the facility can meet the limitations (but in no case later than December 31, 2023, for BA transport water or December 31, 2025, for FGD wastewater), and apply the proposed limitations as of that date (BPT limitations or the facility's other applicable permit limitations would apply until such date).

As proposed, the "as soon as possible" date determined by the permitting authority is November 1, 2020, unless the permitting authority determines another date after receiving facility-specific information submitted by the discharger.[101] EPA is not proposing to revise the specified factors that the permitting authority must consider in determining the as soon as possible date. Assuming that the permitting authority receives relevant, site-specific information

[101] 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, and the FGD wastewater requirements within 26 to 34 months.

from each discharger, in order to determine what date is "as soon as possible" within the implementation period, the factors established in the 2015 rule are:

(a) Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final rule.[102]

(b) Changes being made or planned at the facility in response to greenhouse gas regulations for new or existing fossil fuel-fired 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.

(d) Other factors as appropriate.

The EPA proposes to clarify that the discharger must provide relevant, site-specific information for consideration of these factors by the permitting authority. 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, and the EPA solicits comment on other potential misunderstandings of the factors presented in the 2015 rule that may have caused confusion or led to misunderstandings.

As specified in factor (b), the permitting authority must also consider scheduling for installation of equipment, which includes a consideration of facility changes planned or being made to comply with certain other key rules that affect the steam electric power generating

[102]Cooperatives and municipalities presented information to the 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.

industry. As specified in factor (c), for the FGD wastewater requirements only, the permitting authority must consider whether it is appropriate to allow more time for implementation in order to ensure that the facility has appropriate time to optimize any relevant technologies.

The “as soon as possible” date determined by the permitting authority may or may not be different for each wastestream. The permitting authority should provide a well-documented justification of how it determined the “as soon as possible” date in the fact sheet or administrative record for the permit. If 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. In cases where the facility is already operating the proposed BAT technology basis for a specific wastestream (e.g., dry FA handling system), operates the majority of the proposed BAT technology basis (e.g., FGD chemical precipitation and biological treatment, without sulfide addition), or expects that relevant treatment and process changes would be in place prior to November 1, 2020 (for example due to the CCR rule), it would not usually be appropriate to allow additional time beyond that date. Regardless, in all cases, the permitting authority would make clear in the permit by what date the facility must meet the proposed limitations, and that date, as proposed, would be no later than December 31, 2023, for BA transport water, or December 31, 2025, for FGD wastewater.

Where a discharger chooses to participate in the VIP and be subject to effluent limitations for FGD wastewater based on membranes, the permitting authority must allow the facility up to December 31, 2028, to meet those limitations. Again, the permit must make clear that the facility must meet the limitations by December 31, 2028.

2. Implementation for the Low Utilization Subcategory

The EPA is proposing to establish a new subcategory for low utilization boilers with net generation below 876,000 MWh per year. The EIA defines net generation as, "The amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. Note: Electricity required for pumping at pumped-storage plants is regarded as electricity for station service and is deducted from gross generation."[103] Unlike other subcategories, which often require that a facility possess some static characteristic (e.g., less than 50 MW nameplate capacity), the proposed low utilization subcategory is based on the fluctuating net generation reported annually to the EIA. Thus, the EPA is clarifying how permitting authorities can determine whether a facility qualifies for this subcategorization, and how limitations for boilers in this subcategorization are to be implemented.

a. Determining Boiler Net Generation

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. This average should primarily be collected and calculated using data developed for reporting to the EIA, since using net generation information already collected for the EIA will both eliminate the potentially unnecessary paperwork burden of a separate information gathering and calculations and allow the permitting authority to more easily verify the accuracy of the reported values. If it is necessary for a facility to apportion facility-wide

[103] *See* EIA Glossary, available online at: *https://www.eia.gov/tools/glossary/index.php?id=N*

energy consumption not specifically attributable to individual boilers, the facility must apportion this consumption proportionally, by boiler nameplate capacity, unless it adequately documents a sufficient rationale for an alternate apportionment. 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. 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.

b. Tiering Limitations

In cases where a facility seeks to have limitations for this subcategory incorporated into its permit, the EPA is proposing that a permitting authority incorporate two additional features. First, the EPA is proposing that the limitations for this subcategory be included as the first of two sets of limitations. The second set of limitations would be those applicable to the rest of the steam electric generation point source category. Second, the EPA is proposing that these tiered limits have a two-year timeframe to be implemented for a facility exceeding the two-year net generation requirements as measured per calendar year. For example, if a facility reported it exceeded a two-year average net generation of 876,000 MWh for a unit, it would have two years before discharges of FGD wastewater and BA transport water would henceforth be subject to the second tier of limitations.[104] Application of the second tier would preclude future use of the low utilization subcategory.

[104] Once a facility installs the capital equipment needed to meet the second tier of limitations, O&M costs will be proportional to the utilization of the boiler, and thus would no longer result in disproportionate costs.

These tiered limitations would ensure that, if a boiler that qualified for this subcategorization changes its operation such that it no longer qualifies, it would be automatically subject to the second set of limitations. An automatic feature makes sense for several reasons. Tiered limitations are beneficial to the regulated facility because they provide certainty that the facility would not be considered in violation of its permit initially, when exceeding the required net generation, nor subsequently, during the two-year timeframe over which it has to meet the second tier of effluent limitations. Two years is also consistent with the engineering documents provided to the EPA for the installation of the appropriate technologies. Tiered limitations are beneficial to the state because they avoid the potentially onerous permit modification process and its burden to the permitting authority. Finally, tiered limitations are beneficial to the environment because they ensure a timely transition to more stringent limitations as soon as the reason for the less stringent limitations (disproportionate cost) is gone. The EPA solicits comment on the inclusion of tiered limitations.

3. Addressing Withdrawn or Delayed Retirement

Since the 2015 rule, the EPA has learned of several instances when facilities have withdrawn or delayed retirement announcements for coal-fired boilers and facilities. These instances can be grouped into two categories. First, some delays were involuntary, resulting from orders issued by the Department of Energy (DOE) or Public Utility Commissions (PUCs). The remaining announcements were withdrawn or delayed voluntarily due to changed circumstances. While both the voluntary and involuntary changes to announced retirements were infrequent, the EPA acknowledges that such changes will necessarily impact a facility’s status with regard to some of the new subcategories in today’s proposal. These situations are discussed below. For further information on announced retirements, *see* DCN SE07207.

a. Involuntary Retirement Delays

At least five facilities with announced retirement dates had those dates involuntarily delayed as a result of the DOE issuing orders under Section 202(c) of the Federal Power Act, or a PUC issuing a reliability must-run agreement. Such involuntary operations have raised questions about the conflict between legal obligations to produce electricity and legal obligations under environmental statutes.[105] Today's proposal would subcategorize low utilization boilers and boilers retiring by 2028, subjecting those subcategories to less stringent limitations. However, both utilization and retirement could be impacted by involuntary orders and agreements. Thus, the EPA proposes a savings clause that would be included in all permits where a facility seeks limitations under one of these two subcategories. Such a savings clause would protect a facility which involuntarily fails to qualify for the subcategory for low utilization or retiring boilers, and would allow that facility to prove that, but for the order or agreement, it would have qualified for the subcategory. The EPA solicits comment on whether the proposed savings clause is broad enough to address all scenarios that may result in a mandatory order to operate a boiler.

b. Voluntary Retirement Withdrawals and Delays

Units at five facilities with announced retirement dates had those dates voluntarily withdrawn or delayed due to changed situations, including market conditions, unavailability of natural gas pipelines, changes in environmental regulations, and sale of the facility. Like the involuntary retirement delays discussed in the section above, these situations could impact a

---

[105] Moeller, James. 2013. *Clean air vs. electric reliability: The case of the Potomac River Generating Station*. September. Available online at: *https://scholarlycommons.law.wlu.edu/cgi/viewcontent.cgi?referer=https://www.google.com/&httpsredir=1&article=1077&context=jece*.

facility's qualification for the proposed subcategories for low utilization boilers and boilers retiring by 2028. Unlike the involuntary retirement delays, these voluntary delays and withdrawals can be accounted for through the normal integrated resource planning process. Thus, the EPA does not propose a similar savings clause for such units. Instead, a facility should carefully plan its implementation of the ELGs.

B. Reporting and Recordkeeping Requirements

This proposal includes five new reporting and recordkeeping standards. First, the EPA is proposing a reporting and recordkeeping standard for facilities operating high recycle rate BA systems. The EPA is proposing that such facilities submit the calculation of the primary active wetted BA system volume, 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. This ensures that the permitting authority can verify the volume of discharge allowed for a high recycle rate system. The EPA solicits 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.

Second, the EPA is proposing a reporting and recordkeeping requirement for facilities seeking subcategorization of low utilization boilers. The EPA is proposing that, as part of any permit renewal or re-opening, such facilities submit a calculation of the two-year average net generation for each applicable boiler to the permitting authority, including underlying information. Once any limitations of this subcategory are applicable, the EPA is proposing that such a facility 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. As proposed, if a boiler exceeds the MWh requirements of this subcategory, no further recordkeeping or reporting would be required, as this boiler would be treated the same as the rest of the steam electric point source category after the necessary treatment equipment was installed and operational at the end of two years.

Third, as described in Section VII.C.2, facilities with boilers that qualify for the low-utilization subcategory and that discharge BA transport water, would be required to develop and implement a BMP plan to minimize the discharge of pollutants by recycling as much BA transport water as practicable back to the BA handling system. As part of any permit renewal or any re-opening, such facilities would need to submit their facility-specific plan (certified that it meets the proposed requirements of 40 CFR 423.13(k)(3)) along with a certification that the plan is being implemented. For each permit renewal, the plan and PE certification should be updated and provided to the permitting authority.

Fourth, the EPA is proposing reporting and recordkeeping requirements for facilities seeking subcategorization for a boiler(s) retiring by December 31, 2028. The EPA is proposing that, as part of the permit renewal or re-opening, which are when a facility would make this request, such 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. 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.

Finally, the EPA is proposing reporting and recordkeeping requirements for facilities invoking the proposed savings clause. The EPA is proposing that such facilities must demonstrate that a boiler would have qualified for the subcategory at issue, if not for the emergency order issued by the DOE under Section 202(c) of the Federal Power Act or PUC reliability must-run agreement. Furthermore, the EPA is proposing to require a copy of such order or agreement as an attachment to the submission.

C. Site-Specific Water Quality-Based Effluent Limitations

The EPA regulations at 40 CFR 122.44(d)(1) require that each NPDES permit shall include any requirements, in addition to or more stringent than effluent limitations guidelines or standards promulgated pursuant to sections 301, 304, 306, 307, 318 and 405 of the CWA, necessary to achieve water quality standards established under section 303 of the CWA, including state narrative criteria for water quality. Furthermore, those same regulations require that limitations must control all pollutants, or pollutant parameters (either conventional, nonconventional, or toxic pollutants) which the Director determines are or may be discharged at a level which will cause, have the reasonable potential to cause, or contribute to an excursion above any state water quality standard, including state narrative criteria for water quality.

Bromide was discussed in the preamble to the 2015 rule as a parameter for which water quality-based effluent limitations may be appropriate. The EPA stated its recommendation that permitting authorities carefully consider whether water quality-based effluent limitations on bromide or TDS would be appropriate for FGD wastewater discharges from steam electric facilities upstream of drinking water intakes. The EPA also stated its recommendation that the permitting authority notify any downstream drinking water treatment plants of the discharge of bromide.

The EPA is not proposing additional limitations on bromide for FGD wastewater beyond the removals that might be accomplished by facilities choosing to implement the VIP limitations, though the EPA is soliciting comment on the three potential bromide-specific sub-options presented in Section VII of this preamble. The record continues to suggest that state permitting authorities should consider establishing water quality-based effluent limitations that are protective of populations served by downstream drinking water treatment facilities. As described in Section XII, the analysis of changes in human health benefits associated with changes in bromide discharges are concentrated at a small number of sites. This supports the EPA's determination that potential discharges are best addressed using site-specific, water quality-based effluent limitations established by permitting authorities for the small number of steam electric facilities that may impact downstream drinking water treatment facilities.

XV. Related Acts of Congress, Executive Orders, and Agency Initiatives

A. Executive Orders 12866 (Regulatory Planning and Review) and 13563 (Improving Regulation and Regulatory Review)

This proposed rule is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential social costs and benefits associated with this action. This analysis is contained in Chapter 13 of the BCA, available in the docket. The analysis in the BCA builds on compliance costs and certain other assumptions regarding compliance years discussed in the RIA to estimate the incremental social costs and benefits of the four proposed options relative to the baseline. Analyzing the options against the baseline enables the Agency to characterize the incremental impact of ELG revisions proposed by this action.

Table XV-1 presents the annualized value of the social costs and benefits over 27 years and discounted using a three percent discount rate as compared to the updated baseline. Table

XV-2 presents annualized values using a seven percent discount rate. In both tables, negative costs indicate avoided costs (*i.e.*, cost savings) and negative benefits indicate forgone benefits.

TABLE XV-1. Total Monetized Annualized Benefits And Costs Of Proposed Regulatory Options (Million of 2018$, three percent discount rate)[a]

Regulatory Option	Total social costs[b]	Total monetized benefits[c,d,e]		
		Low Estimate	**Mid Estimate**	**High Estimate**
Option 1	-$130.6	-$41.0	-$43.6	-$86.6
Option 2	-$136.3	$14.8	$19.6	$68.5
Option 3	-$90.1	$35.1	$41.3	$109.4
Option 4	$11.9	$98.4	$105.9	$188.9

a. All social costs and benefits were annualized over 27 years using a 3% discount rate. Negative costs indicate avoided costs and negative benefits indicate forgone benefits. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding.

b. Total social costs are compliance costs to facilities accounting for the timing those costs are incurred.

c. Total monetized benefits exclude other benefits discussed qualitatively.

d. The EPA estimated the air-related benefits for Option 2 using the IPM sensitivity analysis scenario that includes the ACE rule in the baseline (IPM-ACE). EPA extrapolated estimates for Options 1 and 3 air-related benefits from the estimate for Option 2 that is based on IPM-ACE outputs. The values for Option 4 air-related benefits were estimated using the IPM analysis scenario that does not include the ACE rule in the baseline. S*ee* Chapter 8 in the BCA for details). The EPA estimated air-related benefits for Options 1 and 3 by multiplying the total costs for each option by the ratio of [air-related benefits / total social costs] for Option 2. The EPA did not monetize benefits of changes in NO_X and SO_2 emissions and associated changes in $PM_{2.5}$ levels for any option.

e. The EPA estimated use and nonuse values for water quality improvements using two different meta-regression models of WTP. One model provides the low and high bounds while a different model provides a central estimate (included in this table under the mid-range column). For this reason, the mid benefit estimate differs from the midpoint of the benefits range. For details, *see* Chapter 5 in the BCA.

TABLE XV-2. Total Monetized Annualized Benefits And Costs Of Proposed Regulatory Options (Million of 2018$, seven percent discount rate)[a]

Regulatory Option	Total social costs[b]	Total monetized benefits[c,d,e]		
		Low Estimate	**Mid Estimate**	**High Estimate**
Option 1	-$154.0	-$13.7	-$16.0	-$53.3
Option 2	-$166.2	$28.4	$32.6	$74.4
Option 3	-$119.5	$37.1	$42.5	$100.9
Option 4	-$27.3	$70.6	$77.2	$148.4

a. All social costs and benefits were annualized over 27 years using a 7% discount rate. Negative costs indicate avoided costs and negative benefits indicate forgone benefits. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding.

b. Total social costs are compliance costs to facilities accounting for the timing those costs are incurred.

c. Total monetized benefits exclude other benefits discussed qualitatively.

[d.] The EPA estimated the air-related benefits for Option 2 using the IPM sensitivity analysis scenario that includes the ACE rule in the baseline (IPM-ACE). EPA extrapolated estimates for Options 1 and 3 air-related benefits from the estimate for Option 2 that is based on IPM-ACE outputs. The values for Option 4 air-related benefits were estimated using the IPM analysis scenario that does not include the ACE rule in the baseline. S*ee* Chapter 8 in the BCA for details). The EPA estimated air-related benefits for Options 1 and 3 by multiplying the total costs for each option by the ratio of [air-related benefits / total social costs] for Option 2. The EPA did not monetize benefits of changes in NO_X and SO_2 emissions and associated changes in $PM_{2.5}$ levels for any option.

[e.] The EPA estimated use and nonuse values for water quality improvements using two different meta-regression models of WTP. One model provides the low and high bounds while a different model provides a central estimate (included in this table under the mid-range column). For this reason, the mid benefit estimate differs from the midpoint of the benefits range. For details, *see* Chapter 5 in the BCA.

B. Executive Order 13771 (Reducing Regulation and Controlling Regulatory Costs)

The proposed regulatory options would be an Executive Order 13771 deregulatory action. Details on the estimated cost savings of the regulatory options are located in the RIA, and in Tables XV-1 and XV-2 above.

C. Paperwork Reduction Act

OMB has previously approved the information collection requirements contained in the existing regulations 40 CFR part 423 under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control number 2040–0281. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

The EPA estimated small changes in monitoring costs at steam electric facilities under the regulatory options presented in today's proposal relative to the baseline. As proposed, these changes would apply to facilities for which the proposed subcategories are applicable. In some cases, in lieu of these monitoring requirements, facilities would have additional paperwork burden such as that associated with certifications and applicable BMP plans. *See* Section VII of this preamble. However, some facilities would also realize savings, relative to the baseline, by no longer monitoring pollutants for some subcategories of boilers (and because their applicable limitations and standards are based on less costly technologies). The EPA projects that the burden associated with the new proposed paperwork requirements would be largely off-set by the reduced burden associated with less monitoring; therefore, the Agency projects that the proposal would have no net effect on the burden of the approved information collection requirements. With respect to permitting authorities, based on the information in its record, the EPA also does not expect any of the regulatory options in today's proposal to increase or decrease their burden. The proposed options would not change permit application requirements or the associated review; they would not affect the number of permits issued to steam electric facilities; nor would the options change the efforts involved in developing or reviewing such permits. Accordingly, the EPA estimated no net change (i.e., no increase or decrease) in the cost burden to federal or state governments or dischargers associated with any of the regulatory options in this proposed rule.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice-and-comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

The Agency certifies that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The basis for this finding is documented in Chapter 8 of the RIA, included in the docket and summarized below.

The EPA estimates that 243 to 478 entities own steam electric facilities to which the regulatory options would apply, of which 79 to 127 are small. These small ownership entities own a total of 139 steam electric facilities. The EPA considered the impacts of the regulatory options presented in this proposal on small businesses using a cost-to-revenue test. The analysis compares the cost of implementing controls for BA and FGD wastewater under the four regulatory options to those under the baseline (which reflects the 2015 rule as explained in Section V of this preamble). Small entities estimated to incur compliance costs exceeding one or more of the one percent and three percent impact thresholds were identified as potentially incurring a significant impact. The EPA's analysis shows that four small entities (municipalities) are expected to incur costs equal to or greater than one percent of revenue to meet the 2015 rule; for two of these municipalities, the costs to meet the 2015 rule exceed three percent of revenue. Cost savings provided under the regulatory options reduce the impacts on these small entities to varying degrees. Option 2 has the greatest mitigating effect on small entities, reducing to 2 the number of small entities incurring costs equal to or greater than one percent of revenue, and to 1 the entities with costs greater than three percent of revenue. Options 1, 3, and 4 have similar mitigating effects, with one fewer small entity incurring costs equal to or greater than one percent of revenue. The number of small entities exceeding either the one or three percent impact threshold in the baseline is small in the absolute and represents small percentages of the total estimated number of small entities; the cost savings provided by the regulatory options further support the EPA's finding of no significant impact on a substantial number of small entities (No SISNOSE).

E. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local, and tribal governments, and the private sector. An action contains a federal mandate if it may result in expenditures of $100 million or more (annually, adjusted for inflation) for state, local, and tribal governments, in the aggregate, or the private sector in any one year ($160 million in 2018).

The EPA finds that this action is not subject to the requirements of UMRA section 203 because the expenditures are less than $160 million or more in any one year. As detailed in Chapter 9 of the RIA, for its assessment of the impact of potential changes in compliance requirements on small governments (governments for populations of less than 50,000), the EPA estimated the changes in costs for compliance with the regulatory options relative to the baseline for different categories of entities. All four regulatory options presented in this proposal result in lower compliance costs (cost savings) when compared to the baseline. Compared to $44.1 million in the baseline, the Agency estimates that the change in maximum cost in any one year to state, local, or tribal governments range from -$23.5 million under Option 1 to -$6.0 million under Option 4, with an incremental cost for Option 2 of -$23.0 million. Compared to $841.3 million in baseline, the incremental cost in any given year to the private sector ranges from -$444.5 million under Option 4 to -$327.5 million under Option 1, with Option 2 having an incremental cost of -$405 million. From these incremental cost values, the EPA determined that none of the regulatory options would constitute a federal mandate that may result in expenditures of $160 million (in 2018 dollars) or more for state, local, and tribal governments in the aggregate, or the private sector in any one year. Chapter 9 of the RIA report provides details of these analyses.

This action is also not subject to the requirements of UMRA section 203 because it contains no regulatory requirements that might significantly or uniquely affect small governments. To assess whether the regulatory options presented in this proposal would affect small governments in a way that is disproportionately burdensome in comparison to the effect on large governments, the EPA compared total incremental costs and incremental costs per facility for small governments and large governments. The EPA also compared the changes in per facility costs incurred for small-government-owned facilities with those incurred by non-government-owned facilities. The Agency evaluated both average and maximum annualized incremental costs per facility. These analyses, which are detailed in Chapter 9 of the RIA, find that small governments would not be significantly or uniquely affected by the regulatory options presented in this proposal.

F. Executive Order 13132: Federalism

Under Executive Order (E.O.) 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments or the EPA consults with state and local officials early in development of the action.

The EPA anticipates that none of the regulatory options presented in this proposed rule would impose incremental administrative burden on states due to issuing, reviewing, and overseeing compliance with discharge requirements. Nevertheless, the EPA solicits comment on examples and data that demonstrate net impacts compared to the 2015 rule baseline which would allow the Agency to evaluate these impacts for the final rule.

As detailed in Chapter 9 of the RIA in the docket for this action, the EPA has identified 160 steam electric facilities owned by state or local governments, of which 16 facilities are estimated to incur costs to comply with the BA transport water and FGD limitations in the 2015 rule. However, all four regulatory options presented in this proposal provide cost savings as compared to the baseline. The difference in the maximum costs of the options as compared to the baseline ranges from -$6 million under Option 4 to -$23.5 million under Option 2. Based on this information, the EPA proposes to conclude that this action would not impose substantial direct compliance costs on state or local governments.

G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications, as specified in E.O. 13175 (65 FR 67249, November 9, 2000). 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.

The EPA assessed potential tribal implications for the regulatory options presented in this proposed rule arising from three main changes: (1) direct compliance costs incurred by facilities; (2) impacts on drinking water systems downstream from steam electric facilities; and (3) administrative burden on governments that implement the NPDES program.

Regarding direct compliance costs, the EPA's analyses show that no steam electric facilities with BA transport water or FGD discharges are owned by tribal governments. Regarding impacts on drinking water systems, the EPA identified 15 public water systems operated by tribal governments that may be affected by bromide discharges from steam electric facilities. These systems serve a total of 18,917 people. The EPA estimated changes in bladder cancer risk and the resulting health benefits for the four regulatory options in comparison to the baseline. This analysis, which is detailed in Chapter 4 of the BCA, finds very small changes in exposure between the baseline and regulatory options, amounting to very small changes in risk for this population. Finally, regarding administrative burden, no tribal governments are currently authorized pursuant to section 402(b) of the CWA to implement the NPDES program. Based on this information, the EPA concluded that none of the regulatory options presented in the proposed rule would have substantial direct effects on tribal governments.

H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is not subject to E.O. 13045 (62 FR 19885, April 23, 1997) because the EPA does not expect that the environmental health risks or safety risks associated with steam electric facility discharges addressed by this action present a disproportionate risk to children. This action's health risk assessments are in Chapters 4 and 5 of the BCA and are summarized below.

The EPA identified several ways in which the regulatory options presented in this proposal could affect children, including by potentially increasing health risks from changes in exposure to pollutants present in steam electric facility FGD wastewater and BA transport water discharges, or through impacts of the discharges on the quality of source water used by public water systems. This increase arises from less stringent pollutant limitations or later deadlines for meeting effluent limitations under certain regulatory options presented in this proposal as compared to the baseline. In particular, the EPA quantified the changes in IQ losses from lead exposure among pre-school children and from mercury exposure in utero resulting from maternal fish consumption under the four regulatory options, as compared to the baseline. The EPA also estimated changes in the number of children with very high blood lead concentrations. Finally, the EPA estimated changes in the lifetime risk of developing bladder cancer due to exposure to trihalomethanes in drinking water. The EPA did not estimate children-specific risk because these adverse health effects normally follow long-term exposure. These analyses show that all of the regulatory options presented in this proposal would have a small, and not disproportionate, impact on children.

I. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not a “significant energy action,” as defined by E.O. 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

The Agency analyzed the potential energy effects of the regulatory options presented in this proposal relative to the baseline and found minimal or no impacts on electricity generation, generating capacity, cost of energy production, or dependence on a foreign supply of energy. Specifically, the Agency’s analysis found that none of the regulatory options would reduce electricity production by more than 1 billion kilowatt hours per year or by 500 megawatts of installed capacity under either of the options analyzed, nor would the option increase U.S. dependence on foreign supplies of energy. For more detail on the potential energy effects of the regulatory options in this proposal, *see* Section 10.7 in the RIA, available in the docket.

J. National Technology Transfer and Advancement Act

This proposed rulemaking does not involve technical standards.

K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA conducted the analysis in three ways. First, the EPA summarized the demographic characteristics of individuals living in proximity to steam electric facilities with BA transport water or FGD discharges and thus are likely to be affected by the facility discharges and changes in air emissions resulting from the regulatory options presented in this proposal. This first analysis focuses on the spatial distribution of minority and low-income groups to determine whether these groups are more or less represented in the populations that are expected to be affected by the regulatory options, based on their proximity to steam electric facilities. The results show that, when compared to state averages, all affected communities are poorer and a large majority of affected communities have more minority residents than average.

Second, the EPA summarized the demographic characteristics of individuals served by public water systems (PWS) downstream from steam electric facilities and potentially affected by bromide discharges. The results show that the majority of county populations potentially affected by changes in drinking water quality as a result of steam electric facility discharges are poorer and have more minority residents than the state average.

Finally, the EPA conducted analyses of populations exposed to steam electric power facility FGD wastewater and BA transport water discharges through consumption of recreationally caught fish by estimating exposure and health effects by demographic cohort. Where possible, the EPA used analytic assumptions specific to the demographic cohorts—e.g., fish consumption rates specific to different racial groups. Recreational anglers and members of their households, including children, are expected to experience forgone benefits from an increase in pollutant concentrations in fish tissue under all of the regulatory options. EPA estimated forgone benefits to children (i.e., IQ decrements) from increased mercury exposure in the populations that live below the poverty line and/or minority populations.

The results show that the regulatory options would result in forgone benefits to these populations and that these changes may disproportionately affect communities in cases where the regulatory options increase pollutant exposure compared to the baseline. Overall however, the EPA's analysis, which is detailed in Chapter 14 of the BCA, finds very small changes in exposure between the baseline and regulatory options, amounting to very small changes in risk for this population. The EPA solicits comment on the assumptions and uncertainties included in this analysis.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a “major rule” as defined by 5 U.S.C. 804(2).

Appendix A to the Preamble: Definitions, Acronyms, and Abbreviations Used in This Preamble

The following acronyms and abbreviations are used in this preamble.

Administrator. The Administrator of the U.S. Environmental Protection Agency.

Agency. U.S. Environmental Protection Agency.

BAT. Best available technology economically achievable, as defined by CWA sections 301(b)(2)(A) and 304(b)(2)(B).

Bioaccumulation. General term describing a process by which chemicals are taken up by an organism either directly from exposure to a contaminated medium or by consumption of food containing the chemical, resulting in a net accumulation of the chemical by an organism due to uptake from all routes of exposure.

BMP. Best management practice.

BA. The ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls. Economizer ash is included when it is collected with BA.

BPT. The best practicable control technology currently available as defined by sections 301(b)(1) and 304(b)(1) of the CWA.

CBI. Confidential Business Information.

CCR. Coal Combustion Residuals.

Clean Water Act (CWA). The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 et seq.), as amended, e.g., by the Clean Water Act of 1977 (Pub. L. 95–217), and the Water Quality Act of 1987 (Pub. L. 100–4).

Combustion residuals. Solid wastes associated with combustion-related power facility processes, including fly and BA from coal-, petroleum coke-, or oil-fired units; FGD solids;

FGMC wastes; and other wastewater treatment solids associated with combustion wastewater. In addition to the residuals that are associated with coal combustion, this also includes residuals associated with the combustion of other fossil fuels.

Direct discharge. (a) Any addition of any "pollutant" or combination of pollutants to "waters of the United States" from any "point source," or (b) any addition of any pollutant or combination of pollutant to waters of the "contiguous zone" or the ocean from any point source other than a vessel or other floating craft which is being used as a means of transportation. This definition includes additions of pollutants into waters of the United States from: Surface runoff which is collected or channeled by man; discharges though pipes, sewers, or other conveyances owned by a State, municipality, or other person which do not lead to a treatment works; and discharges through pipes, sewers, or other conveyances, leading into privately owned treatment works. This term does not include an addition of pollutants by any "indirect discharger."

Direct discharger. A facility that discharges treated or untreated wastewaters into waters of the U.S.

DOE. Department of Energy.

Dry BA handling system. A system that does not use water as the transport medium to convey BA away from the boiler. It includes systems that collect and convey the ash without any use of water, as well as systems in which BA is quenched in a water bath and then mechanically or pneumatically conveyed away from the boiler. Dry BA handling systems do not include wet sluicing systems (such as remote MDS or complete recycle systems).

Effluent limitation. Under CWA section 502(11), any restriction, including schedules of compliance, established by a state or the Administrator on quantities, rates, and concentrations of chemical, physical, biological, and other constituents which are discharged from point sources into navigable waters, the waters of the contiguous zone, or the ocean, including schedules of compliance.

EIA. Energy Information Administration.

ELGs. Effluent limitations guidelines and standards.

EO. Executive Order.

EPA. U.S. Environmental Protection Agency.

FA. Fly Ash

Facility. Any NPDES “point source” or any other facility or activity (including land or appurtenances thereto) that is subject to regulation under the NPDES program.

FGD. Flue Gas Desulfurization.

FGD Wastewater. Wastewater generated specifically from the wet FGD scrubber system that comes into contact with the flue gas or the FGD solids, including, but not limited to, the blowdown or purge from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater.

Fly Ash. The ash that is carried out of the furnace by a gas stream and collected by a capture device such as a mechanical precipitator, electrostatic precipitator, and/or fabric filter. Economizer ash is included in this definition when it is collected with fly ash. Ash is not included in this definition when it is collected in wet scrubber air pollution control systems whose primary purpose is particulate removal.

Groundwater. Water that is found in the saturated part of the ground underneath the land surface.

Indirect discharge. Wastewater discharged or otherwise introduced to a POTW.

IPM. Integrated Planning Model.

Landfill. A disposal facility or part of a facility where solid waste, sludges, or other process residuals are placed in or on any natural or manmade formation in the earth for disposal and which is not a storage pile, a land treatment facility, a surface impoundment, an underground injection well, a salt dome or salt bed formation, an underground mine, a cave, or a corrective action management unit.

MDS. Mechanical drag system.

Mechanical drag system. BA handling system that collects BA from the bottom of the boiler in a water-filled trough. The water bath in the trough quenches the hot BA as it falls from the boiler and seals the boiler gases. A drag chain operates in a continuous loop to drag BA from the water trough up an incline, which dewaters the BA by gravity, draining the water back to the trough as the BA moves upward. The dewatered BA is often conveyed to a nearby collection area, such as a small bunker outside the boiler building, from which it is loaded onto trucks and either sold or transported to a landfill. The MDS is considered a dry BA handling system because the ash transport mechanism is mechanical removal by the drag chain, not the water.

Mortality. Death rate or proportion of deaths in a population.

NAICS. North American Industry Classification System.

NPDES. National Pollutant Discharge Elimination System.

ORCR. Office of Resource Conservation and Recovery.

Paste. 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. A landfill which receives any paste designed to set into a solid after the passage of a reasonable amount of time.

Point source. Any discernable, confined, and discrete conveyance, including but not limited to, any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft from which pollutants are or may be discharged. The term does not include agricultural stormwater discharges or return flows from irrigated agriculture. *See* CWA section 502(14), 33 U.S.C. 1362(14); 40 CFR 122.2.

POTW. Publicly owned treatment works. *See* CWA section 212, 33 U.S.C. 1292; 40 CFR 122.2, 403.3

PSES. Pretreatment Standards for Existing Sources.

Publicly Owned Treatment Works. Any device or system, owned by a state or municipality, used in the treatment (including recycling and reclamation) of municipal sewage or industrial wastes of a liquid nature that is owned by a state or municipality. This includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment. CWA section 212, 33 U.S.C. 1292; 40 CFR 122.2, 403.3.

RCRA. The Resource Conservation and Recovery Act of 1976, 42 U.S.C. 6901 et seq.

Remote MDS. BA handling system that collects BA at the bottom of the boiler, then uses transport water to sluice the ash to a remote MDS that dewaters BA using a similar configuration as the MDS. The remote MDS is considered a wet BA handling system because the ash transport mechanism is water.

RFA. Regulatory Flexibility Act.

SBA. Small Business Administration.

Sediment. Particulate matter lying below water.

Surface water. All waters of the United States, including rivers, streams, lakes, reservoirs, and seas.

Toxic pollutants. As identified under the CWA, 65 pollutants and classes of pollutants, of which 126 specific substances have been designated priority toxic pollutants. *see* appendix A to 40 CFR part 423.

Transport water. Wastewater that is used to convey FA, BA, 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) or minor maintenance events (e.g., replacement of valves or pipe sections).

UMRA. Unfunded Mandates Reform Act.

Wet BA handling system. A system in which BA is conveyed away from the boiler using water as a transport medium. Wet BA systems typically send the ash slurry to dewatering bins or a surface impoundment. Wet BA handling systems include systems that operate in conjunction with a traditional wet sluicing system to recycle all BA transport water (remote MDS or complete recycle system).

Wet FGD system. Wet FGD systems capture sulfur dioxide from the flue gas using a sorbent that has mixed with water to form a wet slurry, and that generates a water stream that exits the FGD scrubber absorber.

List of Subjects in 40 CFR Part 423

Environmental protection, Electric power generation, Power facilities, Waste treatment and disposal, Water pollution control.

Dated: November 4, 2019.

Andrew R. Wheeler,
Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency proposes to amend 40 CFR part 423 as follows:

PART 423— STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

1. The authority citation for part 423 continues to read as follows:

Authority: Secs. 101; 301; 304(b), (c), (e), and (g); 306; 307; 308 and 501, Clean Water Act (Federal Water Pollution Control Act Amendments of 1972, as amended; 33 U.S.C. 1251; 1311; 1314(b), (c), (e), and (g); 1316; 1317; 1318 and 1361).

2. Amend § 423.11 by revising paragraphs (n), (p), and (t) and adding paragraphs (u), (v), (w), (x), (y), (z), (aa), (bb), (cc), and (dd).

§ 423.11 Specialized definitions.

*****

(n) The term flue gas desulfurization (FGD) wastewater means any wastewater generated specifically from the wet flue gas desulfurization scrubber system that comes into contact with the flue gas or the FGD solids, including but not limited to, the blowdown from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, cleaning FGD paste transportation piping, or that is collected in floor drains in the FGD process area is not considered FGD wastewater.

*****

(p) 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), cleaning FGD paste transportation piping, wastewater present in equipment when a facility is retired from service, or maintenance purge water.

*****

(t) The phrase “as soon as possible” means November 1, 2018 (except for purposes of § 423.13(g)(1)(i) and (k)(1)(i), and § 423.16(e) and (g), in which case it means November 1, 2020), unless the permitting authority establishes a later date, after receiving site-specific information from the discharger, which reflects a consideration of the following factors:

(1) Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of this part.

(2) Changes being made or planned at the plant in response to:

(i) New source performance standards for greenhouse gases from new fossil fuel-fired electric generating units, under sections 111, 301, 302, and 307(d)(1)(C) of the Clean Air Act, as amended, 42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C);

(ii) Emission guidelines for greenhouse gases from existing fossil fuel-fired electric generating units, under sections 111, 301, 302, and 307(d) of the Clean Air Act, as amended, 42 U.S.C. 7411, 7601, 7602, 7607(d); or

(iii) Regulations that address the disposal of coal combustion residuals as solid waste, under sections 1006(b), 1008(a), 2002(a), 3001, 4004, and 4005(a) of the Solid Waste Disposal Act of 1970, as amended by the Resource Conservation and Recovery Act of 1976, as amended by the Hazardous and Solid Waste Amendments of 1984, 42 U.S.C. 6906(b), 6907(a), 6912(a), 6944, and 6945(a).

(3) For FGD wastewater requirements only, an initial commissioning period for the treatment system to optimize the installed equipment.

(4) Other factors as appropriate.

(u) The term “FGD paste” means any combination of FGD wastewater treated with fly ash and/or lime prior to being landfilled, that is engineered to form a solid through pozzolanic reactions.

(v) The term “FGD paste transportation piping” means any pipe, valve, or related item used for transporting FGD paste from its point of generation to a landfill.

(w) 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.

(x) The term “high FGD flow” means the maximum daily volume of FGD wastewater that could be discharged by a facility 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.

(y) The term “net generation” means the amount of gross electrical generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries as calculated in paragraph 423.19(e) of this subpart.

(z) The term “low utilization boiler” means any boiler for which the facility owner certifies, and annually recertifies, under 423.19(e) that the two-year average annual net generation is below 876,000 MWh per year.

(aa) The term "primary active wetted bottom ash system volume" means 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).

(bb) The term "tank" means a stationary device, designed to contain an accumulation of wastewater which is constructed primarily of non-earthen materials (*e.g.*, wood, concrete, steel, plastic) which provide structural support.

(cc) The term "maintenance purge water" means any water being discharged subject to paragraphs § 423.13(k)(2)(i) or § 423.16(g)(2)(i).

(dd) 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.

3. Amend § 423.12 by revising paragraph (b)(11).

§ 423.12 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).

*****

(b) ***

(11) The quantity of pollutants discharged in FGD wastewater, flue gas mercury control wastewater, combustion residual leachate, gasification wastewater, or bottom ash maintenance purge water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration listed in table 1:

Table 1 to paragraph (b)(11)

Pollutant or pollutant property	BPT Effluent limitations	
	Maximum for any 1 day (mg/l)	**Average of daily values for 30 consecutive days shall not exceed (mg/l)**
TSS	100.0	30.0
Oil and grease	20.0	15.0

*****

4. Amend § 423.13 by:

a. Revising paragraph (g)(1)(i);

b. Redesignating paragraph (g)(2) as paragraph (g)(2)(i) and revising the newly redesignated paragraph (g)(2)(i);

c. Adding paragraphs (g)(2)(ii) and (g)(2)(iii);

d. Revising paragraphs (g)(3)(i) and paragraph (k)(1)(i);

e. Redesignating paragraph (k)(2) as (k)(2)(ii) and revising newly redesignated (k)(2)(ii); and

f. Adding paragraphs (k)(2)(i), (k)(2)(iii), and (k)(3).

The additions and revisions to read as follows.

§ 423.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

*****

(g)(1)(i) FGD wastewater. Except for those discharges to which paragraph (g)(2) or (g)(3) of this section applies, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table following this paragraph (g)(1)(i). Dischargers must meet the effluent limitations for FGD wastewater in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2020, but no later than December 31, 2025. These effluent limitations apply to the discharge of FGD wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph.

Table 1 to paragraph (g)(1)(i)

Pollutant or pollutant property	BAT Effluent limitations	
	Maximum for any 1 day	**Average of daily values for 30 consecutive days shall not exceed**
Arsenic, total (ug/L)	18	9
Mercury, total (ng/L)	85	31
Selenium, total (ug/L)	76	31
Nitrate/nitrite as N (mg/L)	4.6	3.2

*****

(2)(i) For any electric generating unit with a total nameplate capacity of less than or equal to 50 megawatts, that is an oil-fired unit, or for which the owner has certified pursuant to 423.19(f) will be retired from service by December 31, 2028, the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed for TSS in § 423.12(b)(11).

(ii) For FGD wastewater discharges from a high FGD flow facility, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table following this paragraph (g)(2)(ii). Dischargers must meet the effluent limitations for FGD wastewater in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2020, but no later than December 31, 2023. These effluent limitations apply to the discharge of FGD wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph (g)(2)(ii).

Table 1 to paragraph (g)(2)(ii)

	BAT Effluent limitations	
Pollutant or pollutant property	**Maximum for any 1 day**	**Average of daily values for 30 consecutive days shall not exceed**
Arsenic, total (ug/L)	11	8
Mercury, total (ng/L)	788	356

(iii)(A) For FGD wastewater discharges from a low utilization boiler, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the Table 1 to paragraph (g)(2)(ii). Dischargers must meet the effluent limitations for FGD wastewater in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2020, but no later than December 31, 2023. These effluent limitations apply to the discharge of FGD wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph (g)(2)(iii)(A).

(B) If any low utilization boiler fails to timely recertify that the two year average net generation of such a boiler is below 876,000 MWh per year as specified in § 423.19(e), regardless of the reason, within two years from the date such a recertification was required, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the Table 1 to paragraph (g)(1)(i).

(3)(i) For dischargers who voluntarily choose to meet the effluent limitations for FGD wastewater in this paragraph, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table following this paragraph (g)(3)(i). Dischargers who choose to meet the effluent limitations for FGD wastewater in this paragraph must meet such limitations by December 31, 2028. These effluent limitations apply to the discharge of FGD wastewater generated on and after December 31, 2028.

Table 1 to paragraph (g)(3)(i)

Pollutant or pollutant property	BAT Effluent limitations	
	Maximum for any 1 day	**Average of daily values for 30 consecutive days shall not exceed**
Arsenic, total (ug/L)	5	-
Mercury, total (ng/L)	21	9
Selenium, total (ug/L)	21	11
Nitrate/Nitrite (mg/L)	1.1	0.6
Bromide (mg/L)	0.6	0.3
TDS (mg/L)	351	156

*****

(k)(1)(i) *Bottom ash transport water*. Except 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 no discharge of pollutants in bottom ash transport water. Dischargers must meet the discharge limitation in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2020, but no later than December 31, 2023. This limitation applies to the discharge of bottom ash transport water generated on and after the date determined by the permitting authority for meeting the discharge limitation, as specified in this paragraph (k)(1)(i). Except for those discharges to which paragraph (k)(2) of this section applies, whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant (except when it is used in the FGD scrubber), the resulting effluent must comply with the discharge limitation in this paragraph. 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 (g)(1)(i) of this section.

*****

(2)(i)(A) 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:

(*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.

(B) 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 ten percent of the primary active wetted bottom ash system volume. Discharges shall be measured by computing daily discharges by totaling daily flow discharges.

(ii) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts, that is an oil-fired unit, or for which the owner has certified pursuant to 423.19(f) will be retired from service by December 31, 2028, the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration for TSS listed in § 423.12(b)(4).

(iii)(A) For bottom ash transport water generated by a low utilization boiler, the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration for TSS listed in § 423.12(b)(4),and shall incorporate the elements of a best management practices plan as described in (k)(3) of this section.

(B) If any low utilization boiler fails to timely recertify that the two year average net generation of such a boiler is below 876,000 MWh per year as specified in 423.19(e), regardless of the reason, within two years from the date such a recertification was required, the quantity of pollutants discharged in bottom ash transport water shall be governed by paragraphs (k)(1) and (k)(2)(i) of this section.

(3) Where required in paragraph (k)(2)(iii) of this section, the discharger shall prepare, implement, review, and update a best management practices plan for the recycle of bottom ash transport water, and must include:

(i) Identification of the low utilization coal-fired generating units that contribute bottom ash to the bottom ash transport system.

(ii) A description of the existing bottom ash handling system and a list of system components (*e.g.*, remote mechanical drag system (rMDS), tanks, impoundments, chemical addition). Where multiple generating units share a bottom ash transport system, the plan shall specify which components are associated with low utilization generating units.

(iii) A detailed water balance, based on measurements, or estimates where measurements are not feasible, specifying the volume and frequency of water additions and removals from the bottom ash transport system, including:

(A) Water removed from the BA transport system:

(*1*) To the discharge outfall.

(*2*) To the FGD scrubber system.

(*3*) Through evaporation

(*4*) Entrained with any removed ash

(*5*) Other mechanisms not specified herein.

(B) Entering or recycled to the BA transport system:

(*1*) Makeup water added to the BA transport water system.

(*2*) Bottom ash transport water recycled back to the system in lieu of makeup water.

(*3*) Other mechanisms not specified herein.

(iv) Measures to be employed by all facilities:

(A) Implementation of a comprehensive preventive maintenance program to identify, repair and replace equipment prior to failures that result in the release of bottom ash transport water.

(B) Daily or more frequent inspections of the entire bottom ash transport water system, including valves, pipe flanges and piping, to identify leaks, spills and other unintended bottom ash transport water escaping from the system, and timely repair of such conditions.

(C) Documentation of preventive and corrective maintenance performed.

(v) Evaluation of options and feasibility, accounting for the associated costs, for eliminating or minimizing discharges of bottom ash transport water, including:

(A) Segregating bottom ash transport water from other process water.

(B) Minimizing the introduction of stormwater by diverting (*e.g.*, curbing, using covers) storm water to a segregated collection system.

(C) Recycling bottom ash transport water back to the bottom ash transport water system.

(D) Recycling bottom ash transport water for use in the FGD scrubber.

(E) Optimizing existing equipment (*e.g.*, pumps, pipes, tanks) and installing new equipment where practicable to achieve the maximum amount of recycle.

(F) Utilizing "in-line" treatment of transport water (*e.g.*, pH control, fines removal) where needed to facilitate recycle.

(vi) Description of the bottom ash recycle system, including all technologies, measures, and practices that will be used to minimize discharge.

(vii) A schedule showing the sequence of implementing any changes necessary to achieve the minimized discharge of bottom ash transport water, including the following:

(A) The anticipated initiation and completion dates of construction and installation associated with the technology components or process modifications specified in the plan.

(B) The anticipated dates that the discharger expects the technologies and process modifications to be fully implemented on a full-scale basis, which in no case shall be later than December 31, 2023.

(C) The anticipated change in discharge volume and effluent quality associated with implementation of the plan.

(viii) Description establishing a method for documenting and demonstrating to the permitting/control authority that the recycle system is well operated and maintained.

(ix) The discharger shall perform weekly flow monitoring for the following:

(A) Make up water to the bottom ash transport water system.

(B) Bottom ash transport water sluice flow rate (*e.g.*, to the surface impoundment(s), dewatering bins(s), tank(s), rMDS).

(C) Bottom ash transport water discharge to surface water or POTW.

(D) Bottom ash transport water recycle back to the bottom ash system or FGD scrubber.

*****

5. Amend § 423.16 by:

a. Revising paragraph (e)(1);

b. Adding paragraph (e)(2);

c. Revising paragraph (g)(1); and

d. Adding paragraph (g)(2).

The additions and revisions to read as follows

§ 423.16 Pretreatment standards for existing sources (PSES).

*****

(e)(1) FGD wastewater. Except as provided for in paragraph (e)(2) of this section, for any electric generating unit with a total nameplate generating capacity of more than 50 megawatts, that is not an oil-fired unit, and that the owner has not certified pursuant to § 423.19(f) will be retired from service by December 31, 2028, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table following this paragraph (e). Dischargers must meet the standards in this paragraph by [DATE 3 YEARS AFTER DATE OF FINAL RULE] except as provided for in paragraph (e)(2) of this section. These standards apply to the discharge of FGD wastewater generated on and after [DATE 3 YEARS AFTER DATE OF FINAL RULE].

Table 1 to paragraph (e)(1)

Pollutant or pollutant property	**PSES**	
	Maximum for any 1 day	**Average of daily values for 30 consecutive days shall not exceed**
Arsenic, total (ug/L)	18	9
Mercury, total (ng/L)	85	31
Selenium, total (ug/L)	76	31
Nitrate/nitrite as N (mg/L)	4.6	3.2

(2)(i) For FGD wastewater discharges from a low utilization boiler, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table following this paragraph (e)(2). Dischargers must meet the standards in this paragraph by [DATE 3 YEARS AFTER DATE OF FINAL RULE].

(ii) If any low utilization boiler fails to timely recertify that the two year average net generation of such a boiler is below 876,000 MWh per year as specified in § 423.19(e), regardless of the reason, within two years from the date such a recertification was required, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in Table 1 to paragraph (e)(1).

Table 1 to paragraph (e)(2)(ii)

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	**Average of daily values for 30 consecutive days shall not exceed**
Arsenic, total (ug/L)	11	8
Mercury, total (ng/L)	788	356

*****

(g)(1) Except for those discharges to which paragraph (g)(2) of this section applies, or when the bottom ash transport water is used in the FGD scrubber, for any electric generating unit with a total nameplate generating capacity of more than 50 megawatts, that is not an oil-fired unit, that is not a low utilization boiler, and that the owner has not certified pursuant to § 423.19(f) will be retired from service by December 31, 2028, there shall be no discharge of pollutants in bottom ash transport water. This standard applies to the discharge of bottom ash transport water generated on and after [DATE 3 YEARS AFTER DATE OF FINAL RULE]. Except for those discharges to which paragraph (g)(2) of this section applies, whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant (except when it is used in the FGD scrubber), the resulting effluent must comply with the discharge standard in this paragraph. 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) of this section.

(2)(i)(A) 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:

(*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 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 current operations at the facility are unable to currently manage pH, corrosive compounds, and fine particulates to below levels which impact system operations.

(B) The total volume necessary to be discharged to a POTW 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 ten percent of the primary active wetted bottom ash system volume. Discharges shall be measured by computing daily discharges by totaling daily flow discharges.

(ii)(A) For bottom ash transport water generated by a low utilization boiler, the quantity of pollutants discharged in bottom ash transport water shall incorporate the elements of a best management practices plan as described in § 423.13(k)(3).

(B) If any low utilization boiler fails to timely recertify that the two year average net generation of such a boiler is below 876,000 MWh per year as specified in § 423.19(e), regardless of the reason, within two years from the date such a recertification was required, the quantity of pollutants discharged in bottom ash transport water shall be governed by paragraphs (g)(1) and (g)(2)(i) of this section.

6. Add § 423.18 to read as follows.

§ 423.18 Permit conditions.

All permits subject to this part shall include the following permit conditions:

(a) In case of an emergency order issued by the Department of Energy under Section 202(c) of the Federal Power Act or a Public Utility Commission reliability must run agreement, a boiler shall be deemed to qualify as a low utilization boiler or boiler that will be retired from service by December 31, 2028 if such qualification would have been demonstrated absent such order or agreement.

(b) Any facility providing the required documentation pursuant to § 423.19(g) may avail itself of the protections of this permit condition.

7. Add § 423.19 to read as follows.

§ 423.19 Reporting and recordkeeping requirements.

(a) Discharges subject to this part must comply with the following reporting requirements in addition to the applicable requirements in 40 CFR 403.12(b), (d), (e), and (g).

(b) *Signature and certification*. Unless otherwise provided below, all certifications and recertifications required in this part must be signed and certified pursuant to 40 CFR 122.22 for direct dischargers or 40 CFR 403.12(l) for indirect dischargers.

(c) Requirements for facilities discharging bottom ash transport water pursuant to § 423.13(k)(2)(i) or § 423.16(g)(2)(i).

(1) *Initial Certification Statement*. For sources seeking to discharge bottom ash transport water pursuant to § 423.13(k)(2)(i) or § 423.16(g)(2)(i), an initial certification shall be submitted to the permitting authority by the as soon as possible date determined under § 423.11(t), or the control authority by [DATE 3 YEARS AFTER DATE OF FINAL RULE] in the case of an indirect discharger.

(2) *Signature and certification*. The certification statement must be signed and certified by a professional engineer.

(3) *Contents*. An initial certification shall include the following:

(A) A statement that the professional engineer is a licensed professional engineer.

(B) A statement that the professional engineer is familiar with the regulation requirements.

(C) A statement that the professional engineer is familiar with the facility.

(D) The primary active wetted bottom ash system volume in § 423.11(aa).

(E) All assumptions, information, and calculations used by the certifying professional engineer to determine the primary active wetted bottom ash system volume.

(d) Requirements for a bottom ash best management practices plan.

(1) *Initial and Annual Certification Statement*. For sources required to develop and implement a best management practices plan pursuant to § 423.13(k)(3), an initial certification

shall be made to the permitting authority with a permit application, or to the control authority no later than [DATE 3 YEARS AFTER DATE OF FINAL RULE] in the case of an indirect discharger, and an annual recertification shall be made to the permitting authority, or control authority in the case of an indirect discharger, within 60 days of the anniversary of the original plan.

(2) *Signature and Certification*. The certification statement must be signed and certified by a professional engineer.

(3) *Contents for Initial Certification*. An initial certification shall include the following:

(A) A statement that the professional engineer is a licensed professional engineer.

(B) A statement that the professional engineer is familiar with the regulation requirements.

(C) A statement that the professional engineer is familiar with the facility.

(D) The approved best management practices plan.

(E) A statement that the best management practices plan is being implemented.

(4) *Additional Contents for Annual Certification*. In addition to the required contents of the initial certification in paragraph (d)(3) of this section an annual certification shall include the following

(A) Any updates to the best management practices plan.

(B) An attachment of weekly flow measurements from the previous year.

(C) The average amount of recycled bottom ash transport water in gallons per day.

(D) Copies of annual inspection reports and a summary of preventative maintenance performed on the system.

(E) A statement that the plan and corresponding flow records are being maintained at the office of the plant.

(e) *Requirements for low utilization boilers*. (1) Initial and Annual Certification Statement. For sources seeking to apply the limitations or standards for low utilization boilers, an initial certification shall be made to the permitting authority with a permit application, or to the control authority no later than [DATE 3 YEARS AFTER DATE OF FINAL RULE] in the case of an indirect discharger, and an annual recertification shall be made to the permitting authority, or control authority in the case of an indirect discharger, within 60 days of submitting annual net generation data to the Energy Information Administration.

(2) *Contents*. A certification or annual recertification shall be based on the information submitted to the Energy Information Administration and shall include copies of the underlying forms submitted to the Energy Information Administration, as well as any supplemental information and calculations used to determine the two year average annual net generation. Where station-wide energy consumption must otherwise be apportioned to multiple boilers, the facility shall attribute such consumption to each boiler proportional to that boiler’s nameplate capacity unless the facility can demonstrate the energy consumption is specific to a boiler.

(f) Requirements for units that will be retired from service by December 31, 2028 pursuant to §§423.13(k)(2)(ii) and 423.13(g)(1).

(1) *Initial Certification Statement*. For sources seeking to apply the limitations or standards for units that will be retired from service by December 31, 2028, a one-time certification to the permitting authority 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), or to the control authority by [promulgation date + 3 years] in the case of an indirect discharger.

(2) *Contents*. A certification shall include the estimated date that boiler will be retired from service, a brief statement as to the reason for retirement, as well as a copy of the most recent integrated resource plan, certification of boiler cessation under 40 CFR 257.103(b), or other legally binding submission supporting that the boiler will be retired from service by December 31, 2028.

(g) Requirements for facilities seeking the protections of § 423.18.

(1) *Certification Statement*. For sources seeking to apply the protections of the permit conditions in § 423.18, a one-time certification shall be submitted to the permitting authority, or control authority in the case of an indirect discharger, no later than 30 days from receipt of the order or agreement attached pursuant to paragraph (f)(2) of this section.

(2) *Contents*. A certification statement must demonstrate that a boiler would have qualified for the subcategory at issue absent the emergency order issued by the Department of Energy under Section 202(c) of the Federal Power Act or Public Utility Commission reliability must run agreement; and a copy of such order or agreement shall be attached.

[FR Doc. 2019-24686 Filed: 11/21/2019 8:45 am; Publication Date: 11/22/2019]