ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 423

[EPA–HQ–OW–2009–0819; FRL–10014–41–OW]

RIN 2040–AF77

Steam Electric Reconsideration Rule

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA or the Agency) is finalizing 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 final regulation is estimated to save approximately $140 million annually in after tax compliance costs as a result of less costly FGD wastewater technologies that could be used with the modification of the Steam Electric Power Generating Effluent Guidelines 2015 rule (the 2015 rule) limitations; less costly BA transport water technologies made possible by the revision of the 2015 rule's zero discharge limitations; a two-year extension of compliance time frames for meeting FGD wastewater and BA transport water limitations, and additional subcategories for both FGD wastewater and BA transport water. Participation in the voluntary incentive program would contribute to the reduction in pollutant discharges by these steam electric power plants in FGD wastewater by approximately 26.7 million pounds per year.

DATES: This final rule is effective on December 14, 2020. In accordance with 40 CFR part 23, this regulation shall be considered issued for purposes of judicial review at 1:00 p.m. Eastern time on October 27, 2020. Under section 509(b)(1) of the CWA, judicial review of this regulation can be had only by filing a petition for review in the U.S. Court of Appeals within 120 days after the regulation is considered issued for purposes of judicial review. Under section 509(b)(2), the requirements in this regulation may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OW–2009–0819. All documents in the docket are listed on the *http://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov*.

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, EPA defines terms and acronyms in Appendix A.

Supporting Documentation. Today's final rule is supported by numerous documents including:

- *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental TDD), Document No. EPA–821–R–20–001. The Supplemental TDD summarizes the technical and engineering analyses supporting the final rule. It presents EPA's updated analyses supporting the revisions to FGD wastewater and BA transport water. These updates include additional data collected since the signature of the 2015 rule, updates to the industry (*e.g.,* retirements, updates to FGD treatment and BA handling), cost methodologies, pollutant removal estimates, corresponding non-water quality environmental impacts associated with updated FGD and BA methodologies, and explanations of the calculations of the effluent limitations and standards. 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 of EPA's data collection, description of the industry, and underlying analyses supporting the ELGs established for other wastestreams in the 2015 rule.
- *Supplemental Environmental Assessment for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental EA), Document No. EPA–821–R–20–002. The Supplemental EA summarizes the potential environmental and human health impacts that are estimated to result from implementation of this final rule.
- *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA Report), Document No. EPA–821–R–20–003. The BCA Report summarizes estimates of the societal benefits and costs resulting from implementation of this final rule.
- *Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA), Document No. EPA–821–R–20–004. The RIA presents a profile of the steam electric power generating industry, a summary of estimated costs and impacts associated with this final rule, and an assessment of the potential impacts on employment and small businesses.
- *Response to Public Comments for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.* This document provides EPA's responses to substantive public comments received on the 2019 proposed rule.
- *Docket Index for the Revisions to the Steam Electric ELGs.* This document provides a list of the additional memoranda, references, and other information relied upon by EPA for this final rule.

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

I. Executive Summary

A. Purpose of Rule

Coal-fired plants are affected by several environmental regulations. One of these regulations, the Steam Electric Power Generating ELGs, was promulgated in 2015 (80 FR 67838; November 3, 2015) and applies to the subset of the electric power industry in which ''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 FGD wastewater, fly ash (FA) transport water, BA transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non-chemical metal cleaning wastes.

Since the Steam Electric Power Generating ELGs were revised in 2015, steam electric power plants have installed more affordable technologies that can remove similar amounts of pollution as those operating in 2015. This final rule revises limitations and standards for two of the wastestreams addressed in the 2015 rule: BA transport water and FGD wastewater. Today's rule does not revise the other wastestreams covered by the 2015 rule.

B. Summary of Final Rule

For existing sources that discharge directly to surface water, with the subcategories discussed below excepted, the final rule establishes the following effluent limitations based on Best Available Technology Economically Achievable (BAT):

• For FGD wastewater, the final rule establishes numeric BAT effluent limitations on mercury, arsenic, selenium, and nitrate/nitrite as nitrogen.[1]

- For BA transport water, the final rules establishes as BAT a high recycle rate system with a site-specific volumetric purge (defined in the final rule as BA purge water) which cannot exceed 10 percent of the BA transport water system's volume where the purge volume and associated effluent limitations are established by the permitting authority.

The final rule includes separate requirements for the following subcategories: High FGD flow plants, electric generating units (EGUs) that will permanently cease the combustion of coal by 2028, and low utilization EGUs (LUEGUs). The 2015 rule's subcategories for oil-fired EGUs and small generating units (50 MW or less) were not reopened in this rulemaking and remain in effect. For high FGD flow plants (FGD wastewater flows over four million gallons per day, after accounting for the plant's ability to recycle the wastewater to the maximum limits of the FGD system's materials of construction) and LUEGUs (those with a capacity utilization rating (CUR) of less than 10 percent), the final rule establishes BAT limitations in the discharged FGD wastewater as numeric effluent limitations on mercury and arsenic. For LUEGUs, the final rule establishes BAT limitations for BA transport water for total suspended solids (TSS) and also includes standards for implementing a best management practices (BMP) plan. For EGUs permanently ceasing the combustion of coal by 2028, the final rule establishes BAT limitations for total suspended solids (TSS) in FGD wastewater and bottom ash transport water.

The final rule establishes a voluntary incentives program that provides the certainty of more time (until December 31, 2028) for plants to meet 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 TSS in FGD wastewater. The optional program offers environmental protections beyond those achieved by the final BAT limitations, while providing plants that opt into the program more flexibility when permeate or distillate is used as boiler makeup water, and additional time to meet the limitations established for BAT in this final rule.

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

Where BAT limitations in this rule are more stringent than previously established BPT limitations applicable to the relevant wastestreams, those limitations do not apply until the permitting authority determines a date that is as soon as possible on or after October 13, 2021, but no later than December 31, 2025.

C. Summary of Costs and Benefits

EPA estimates that the final rule will save $127 million per year in social costs and result in between $−1.7 million and $43 million in benefits, using a three percent discount rate, and will save $153 million per year in social costs and between $6.5 million and $46 million in benefits, using a seven percent discount. Table XV–1 summarizes the benefits and social costs for the four regulatory options that EPA analyzed at a three percent discount rate. EPA's analysis reflects the Agency's understanding of the actions steam electric power plants are expected to take to meet the limitations and standards in the final rule. EPA based its analysis on a modeled baseline that reflects the expected effects of announced retirements and fuel conversions, impacts of relevant final rules such as the Coal Combustion Residuals (CCR) Part A final rule that the Agency promulgated in August 2020 and the Affordable Clean Energy (ACE) rule that the Agency promulgated in 2019, and full implementation of the 2015 rule. EPA has also provided an assessment of the economic impacts of the final revised Steam Electric ELGs relative to an alternative baseline including the CCR Part B Rule, which EPA is working on but which has not been issued at this time (see DCN SE09360). EPA understands that these modeled results have uncertainty and that the actual costs for individual plants 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 Comments and Online Public Hearing

During the 60-day public comment period for the 2019 proposed rule (November 22, 2019 to January 21, 2020), EPA received more than 7,400 public comment submissions from private citizens, industry members, technology vendors, government entities, environmental groups, and trade associations. EPA also hosted an online public hearing on December 19, 2019 (during the public comment period). The hearing had 110 attendees, 32 of whom spoke about the proposed rule. Available documents from the public hearing include the presentation given by EPA and a transcript (DCN SE08497 and DCN SE08498).

III. General Information

A. Does this action apply to me?

Entities potentially regulated by the final rule include:

Category	Example of regulated entity	North American industry classification system (NAICS) code
Industry	Electric Power Generation Plants—Electric Power Generation	22111
	Electric Power Generation Plants—Fossil Fuel Electric Power Generation	221112

This section is not intended to be exhaustive, but to provide a guide to entities likely to be regulated by the final rule. Other types of entities that do not meet the above criteria could also be regulated. To determine whether your plant is regulated by the final rule, you should carefully examine the applicability criteria listed in 40 CFR

[1] While the proposed rule described ''two sets'' of BAT limitations for both FGD wastewater and BA transport water, this rulemaking has been focused on revisions to the 2015 rule limitations and standards that were new and more stringent than previously established BPT limitations and standards (the ''second set'' of limitations). It was not intended to address the TSS BAT limitations for these wastestreams promulgated in the 2015 rule (the ''first set'' of limitations), which have since been vacated by the U.S. Court of Appeals for the Fifth Circuit, see Section IV.D, below.

423.10 and the definitions in 40 CFR 423.11 of the 2015 rule, as amended by this final rule. If you still have questions regarding the applicability of the final rule to a particular entity, consult the person listed for technical information in the preceding section, titled **FOR FURTHER INFORMATION CONTACT**.

B. What action is EPA taking?

EPA is revising certain BAT ELGs 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 EPA's authority for taking this action?

EPA is finalizing 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 $127 million per year in social costs and result in between −$1.7 million and $43 million in benefits, using a 3 percent discount rate. Using a 7 percent discount rate, the estimated savings are $153 million per year and benefits are between $6.5 million and $46 million.

IV. Background

A. Clean Water Act (CWA)

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 EPA to establish national technology-based ELGs and new source performance standards (NSPS) for discharges into waters of the United States from categories of point sources (such as industrial, commercial, and public sources).

The CWA also authorizes 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). 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 ELGs (CWA sections 301 and 304, 33 U.S.C. 1311 and 1314) and NSPS (CWA section 306, 33 U.S.C. 1316) promulgated by EPA, or are based on best professional judgment (BPJ) where EPA has not promulgated an applicable ELG 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 CWA (*e.g.,* BPT, BCT, BAT; see below).

EPA promulgates national ELGs for industrial categories for three classes of pollutants: (1) Conventional pollutants (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

EPA establishes ELGs based on the performance of well-designed and well-operated control and treatment technologies. The legislative history also supports that 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 various levels of control applicable to direct and indirect dischargers, based on the type of pollutant controlled. The three standards relevant to this rulemaking are described in detail below.

1. Best Practicable Control Technology Currently Available (BPT)

Traditionally, 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. EPA promulgates BPT effluent limitations for conventional, toxic, and nonconventional pollutants. In specifying BPT, EPA looks at a number of factors. 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. CWA section 304(b)(1)(B), 33 U.S.C. 1314(b)(1)(B). If, however, existing performance is uniformly inadequate, 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, 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 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 and 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 the factors it is required to consider. *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1045 (D.C. Cir. 1978). Generally, 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 may 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 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 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 Steam Electric Power Generation Point Source Category Rule

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 power plants, 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 last been updated in 1982.

New technologies for generating electric power and the widespread implementation of air pollution controls over the last several decades have altered wastewater streams or created new wastewater streams at many steam electric power plants, particularly coal-fired plants. Discharges in these wastestreams include arsenic, lead, mercury, selenium, chromium, and cadmium. Many of these toxic pollutants can be persistent, meaning once in the environment they can remain there for years.

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, FA transport water, and gasification wastewater. The rule required most steam electric power plants 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 NPDES permitting authority (typically a state environmental agency) would determine the particular compliance date(s) for each plant in the NPDES permit.

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 power plants are allowed to discharge by 1.4 billion pounds and reduce water withdrawal by 57 billion gallons. At the time, EPA estimated annual compliance costs for the final rule to be $480 million (in 2013$) and estimated benefits associated with the rule to be $451 million to $566 million (in 2013$).

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.*[2] On March 24, 2017, the Utility Water Act Group (UWAG) submitted to 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, 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.[3] 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 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

[2] Case No. 15–60821.

[3] *See Clean Water Action.* v. *EPA,* No. 17–0817 (D.D.C.), appeal dismissed, 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).

leachate, which are not at issue in this final rule, the Fifth Circuit issued a decision on April 12, 2019, vacating those limitations as arbitrary and capricious under the APA and unlawful under the CWA, respectively. EPA plans to address this vacatur in a subsequent action.

In September 2017, 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. EPA also withdrew its prior action taken pursuant to Section 705 of the APA. The rule received multiple legal challenges, but the courts did not sustain any of them [4] and EPA prevailed.

E. Other Ongoing Rules Affecting the Steam Electric Sector

1. Affordable Clean Energy (ACE) Rule

On June 19, 2019, EPA issued the ACE rule pursuant to Clean Air Act (CAA) sections 111(a)(1) and 111(d), providing states with guidelines for establishing standards of performance regulating CO_2 emissions at existing coal-fired electric utility generating units (EGUs).[5] This action was finalized in conjunction with two related, but separate and distinct rulemakings: (1) The repeal of the Clean Power Plan (CPP), and (2) revised implementing regulations for ACE, ongoing emission guidelines, and all future emission guidelines for existing sources issued under the authority of CAA section 111(d).

Under CAA section 111(a)(1) and 111(d), respectively, EPA determines the best system of emission reduction (BSER) and states submit plans establishing standards of performance based on the BSER. The BSER must be applicable to, at, and on the premises of a source that is subject to CAA section 111(d). EPA repealed the CPP on the basis that it in part improperly premised its BSER on power generation that was shifting between EGUs and other, lower-emitting sources. In ACE, EPA determined the BSER for coal-fired EGUs as six heat rate improvements (HRI) ''candidate technologies,'' as well as additional operations and maintenance (O&M) practices, all of which are applicable to and at the source.[6] For each candidate technology, EPA has provided the extent of achievable emissions limitations through application of the BSER as ranges of expected improvements and costs. States are required to submit plans by July 8, 2022 that establish standards of performance for their EGUs that are subject to the ACE rule. The standards of performance must reflect the degree of emissions limitation through application of the BSER, and states may take into account remaining useful life and other factors in applying a standard to a particular EGU. Multiple legal challenges to this rule were consolidated in *American Lung Association* v. *EPA,* No. 19–1140, and are currently pending in the D.C. Circuit Court of Appeals.

2. Coal Combustion Residuals (CCR)

On April 17, 2015, the Agency published the Disposal of Coal Combustion Residuals from Electric Utilities final rule (2015 CCR rule). This rule finalized national regulations to provide a comprehensive set of requirements for the safe disposal of CCR, commonly known as coal ash, from steam electric power plants. The final 2015 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 groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the 2015 CCR rule set recordkeeping and reporting requirements as well as the requirement for each plant to establish and post specific information to a publicly accessible website. This final 2015 CCR rule also supported the responsible recycling of CCR by distinguishing beneficial use from disposal.

As a result of the D.C. Circuit Court rulings in *USWAG* v. *EPA,* No. 15–1219 (D.C. Cir. 2018) and *Waterkeeper Alliance Inc. et al.* v. *EPA,* No. 18–1289 (D.C. Cir. 2019), the Administrator signed *A Holistic Approach to Closure Part A: Deadline to Initiate Closure and Enhancing Public Access to Information* on July 29 (CCR Part A). In particular, four amendments to the CCR rule were finalized which could impact plants' decisions under this final ELG rule. First, the CCR Part A rule establishes a new deadline of April 11, 2021, for all unlined surface impoundments, as well as those surface impoundments that failed the location restriction for placement above the uppermost aquifer, to stop receiving waste and begin closure or retrofit. EPA determined this date after evaluating the steps that owners and operators need to take for surface impoundments to stop receiving waste and begin closure, and the time frames needed for implementation. Second, the rule establishes procedures for plants to obtain additional time to develop alternate capacity to manage their wastestreams (both coal ash and non-coal ash) before they have to stop receiving waste and begin closing their coal ash surface impoundments. Third, the rule changes the classification of compacted-soil-lined and clay-lined surface impoundments from lined to unlined. Finally, the rule revises the coal ash regulations to specify that all unlined surface impoundments are required to retrofit or close. This would not affect the ability of plants to install new, composite-lined surface impoundments.

As explained in the 2015 ELG rule and 2019 ELG proposal, the ELGs and 2015 CCR rule may affect the same EGU or activity at a plant. Therefore, when EPA finalized the ELG and CCR rule in 2015 and proposed revisions to both rules in 2019, the Agency coordinated the ELG and CCR rules to facilitate and minimize the complexity of implementing engineering, financial, and permitting activities. EPA continued to coordinate these two rules during the development of the final rule for ELG and CCR Part A. EPA's analysis now estimates how the CCR Part A rule may affect surface impoundments and the ash handling systems and FGD treatment systems that send wastes to those impoundments. This is further described in Supplemental TDD, Section 3. For more information on the CCR Part A rule and accompanying background documents, visit *www.regulations.gov* Docket EPA–HQ–OLEM–2019–0172 and *www.epa.gov/coalash/coal-ash-rule*.

In addition to the final CCR Part A rule, EPA has proposed further revisions to the CCR regulations (CCR Part B). Specifically, EPA proposed four changes in the CCR Part B rule. First, EPA proposed procedures to allow plants to request approval to continue operating CCR surface impoundments equipped

[4] *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.

[5] 84 FR 32520.

[6] These six technologies are: (1) Neural network/intelligent soot blowers, (2) EGU feed pumps, (3) air heater and duct leakage control, (4) variable frequency drives, (5) blade path upgrade (steam turbine), and (6) redesign/replace economizer.

with an alternate liner. Second, EPA proposed two options to allow the continued placement of CCR in surface impoundments undergoing forced closure. Third, EPA proposed an additional closure option for CCR units being closed by removal of CCR. Finally, EPA proposed requirements for annual closure progress reports. While the Part B proposal was issued after the comment period for the ELG rule had closed and EPA had already taken significant steps to respond to public comments on the ELG rule and develop the final ELG rule, EPA recognizes that, just as with the Part A rule, the first provision of the Part B rule may affect the same EGU or activity at a plant that these final ELGs affect. EPA is continuing to work on the Part B rule and may finalize this provision in the future. Thus, to provide the public with meaningful analysis of the potential overlap and impacts of this final rule with the CCR Part B rule, EPA has conducted a sensitivity analysis that is described further in a memo titled ''Assessment of the economic impacts of the final revised Steam Electric ELGs relative to an alternative baseline including the CCR Part B Rule'', (DCN SE09360). For more information on the CCR Part B rule and accompanying background documents, visit *www.regulations.gov* Docket EPA–HQ–OLEM–2019–0173.

F. Scope of the Final Rule

The final rule revises the new, more stringent BAT ELGs and pretreatment standards for existing sources in the 2015 rule that apply to FGD wastewater and BA transport water.

V. Steam Electric Power Generating Industry Description

A. General Description of Industry

EPA provided a general description of the steam electric power generating industry in the 2013 proposed rule, the 2015 rule, the 2019 proposed rule, and has continued to collect information and update that industry profile. The previous descriptions reflected the known information about the universe of steam electric power plants and incorporated final environmental regulations applicable at that time. For the final rule, as described in the Supplemental TDD, Section 3, 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.[7] The analyses supporting the final rule use an updated baseline that incorporates these changes in the industry. The analyses then compare the effect of the final rule's requirements for FGD wastewater and BA transport water to the effect on the industry (as it exists today) of the 2015 rule's limitations for FGD wastewater and BA transport water.

As described in the Regulatory Impact Analysis, of the 914 steam electric power plants in the country identified by EPA, only those coal-fired power plants that discharge bottom ash transport water or FGD wastewater may incur compliance costs under this final rule. EPA estimates that 108 such plants could have incurred non-zero compliance costs under the 2015 rule but that only 75 plants may incur non-zero compliance costs under this final rule. As described above, this difference is due to plant retirements, fuel conversions, ash handling conversions, wastewater treatment updates, and updated information on capacity utilization discussed in *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule* (DCN SE08688), but does not include additional changes since this document was developed.

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 relatively inexpensive natural gas, emergence of alternative fuel technologies, and continued aging of coal-fired steam electric power plants. These changes have resulted in coal-fired unit and plant 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 rule will have no direct effect on the nuclear-powered sector, except as it might affect relative prices through its effects on coal-fired generation.) In the coal-fired sector, the market forces manifest as scaling back coal-fired power generation (including unit and plant closures) at an accelerated rate. The rate of coal capacity retirement is affected by regulations adopted in the last decade (*e.g.,* CCR, CPP, and the 2015 Steam Electric ELG), that are cited by some power companies when they announce unit or plant closures, fuel switching, or other operational changes. Some utilities are also trending toward supplementing or replacing traditional generation with alternative sources. The electric power infrastructure adjusts to these changes and generally trends toward optimal infrastructure and operations to deliver the country's power demand. Some communities experience negative effects, while for others the effects are positive. The negative distributional effects can be particularly difficult for communities affected by company decisions to scale back or retire a plant. 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 plants with additional ways of meeting effluent limitations, sometimes at a lower cost. For this final rule, EPA incorporated updated information and evaluated several technologies available to control and treat FGD wastewater and BA transport water. See Section VIII of this preamble for details on updated cost information.

1. FGD Wastewater

FGD scrubber systems, either dry or wet, remove sulfur dioxide from flue gas, preventing sulfur dioxide emissions into the air. Dry FGD systems generally do not discharge wastewater, as the water they use evaporates during operation; wet FGD systems do produce a wastewater stream.

Steam electric power plants discharging FGD wastewater currently employ a variety of wastewater treatment technologies and operating/management practices to reduce the pollutants associated with discharged FGD wastewater. As part of the 2015 rule, 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.

[7] The data presented in the general description continue to reflect some conditions existing in 2009, as the industry survey remains EPA's best available source of information for characterizing operations across the industry.

EPA identified three types of biological treatment systems used to treat FGD wastewater: (1) Anoxic/anaerobic fixed-film bioreactors, which remove nitrogen compounds and selenium, as well as other metals; (2) anoxic/anaerobic suspended growth systems, which remove selenium and other metals; and (3) aerobic/anaerobic sequencing batch reactors, which remove 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 a typical hydraulic residence time 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, thermal evaporation systems 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, which produces a solid residue for landfill disposal and additional distillate that can be reused within the plant 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. These systems involve 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, plants typically find it necessary to dilute the FGD wastewater with service water before it enters the wetland.

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

—Complete recycle. Plants that operate in this manner do not produce a saleable solid product from the FGD system (*e.g.,* wallboard-grade gypsum). Because the plants 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 plants 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 plants is greater than or equal to the flow rate of the FGD wastewater plus the rate at which precipitation enters the impoundments; therefore, there is no discharge to surface water.

—FA conditioning. Many plants 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. 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.

As part of the proposed rule, EPA added two additional FGD wastewater treatment technologies to the suite of regulatory options that were evaluated 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 rule as HRTR—high residence time biological reduction). The LRTR system is designed to operate with a shorter residence time (approximately 1 to 4 hours, as compared to a residence time of 10 to 16 hours for HRTR), while still removing significant volumes of selenium and nitrate/nitrite. The LRTR technology option selected for this final rule includes chemical precipitation as a pretreatment stage, followed by the bioreactor, then ultrafiltration as a polishing step.

• Membrane filtration. A membrane filtration system typically combines 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 range 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. The membrane filtration technology option considered for this final rule includes a pretreatment stage.

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 full scale or pilot scale, 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.[8] Many plants 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 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 (remote MDS). These systems use the same processes as wet sluicing to an impoundment or a dewatering bin system to transport bottom ash to a remote MDS. 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)[9] or a high recycle rate system. For the high recycle rate system that serves as the basis for BAT in the final rule, plants 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.

• 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 plant 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 the final rule, EPA identified the following BA handling systems that do not generate bottom ash transport water.

• Mechanical drag system. These systems operate directly underneath the EGU. The bottom ash is collected in a water quench bath. A drag chain conveyor dewaters the

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

[9] Additional treatment may be necessary to maintain a true closed loop system. This additional treatment could include adding a polymer to enhance removal of suspended solids, or membrane filtration of a slip stream to remove dissolved solids.

bottom ash by pulling it out of the water bath on an incline.

- Dry mechanical conveyor. These systems operate directly underneath the EGU. The system uses ambient air to cool the bottom ash in the EGU and then transports the ash out of the EGU on a conveyor. No water is used in this process.
- Dry vacuum or pressure system. These systems transport bottom ash from the EGU 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.
- Compact submerged conveyor.[10] These systems are located directly underneath the EGU 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 transports and dewaters 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, EPA conducted seven site visits to plants in five states. EPA selected plants to visit using information gathered in support of the 2015 rule, information from industry outreach, and publicly available plant-specific information. EPA re-visited four plants that were previously visited in support of the 2015 rule because they had recently conducted, or were currently conducting, FGD wastewater treatment pilot studies. EPA also revisited plants 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. Following the proposal, EPA also conducted five teleconference calls in the spring of 2020. One of these plants was selected for a conference call because it had installed a compact submerged conveyor for management of BA. Two additional plants were selected for a conference call due to installed FGD wastewater technologies that EPA understood could potentially achieve the limitations in the VIP. The final two conference calls were with companies whose plants EPA believed were planning or constructing FGD wastewater technologies that could potentially achieve the limitations in the VIP, based on preliminary information provided by third parties.[11]

The specific objectives of these visits and calls were to gather general information about each plant's operations, pollution prevention and wastewater treatment system operations, ongoing pilot or laboratory scale studies of 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, EPA requested supplemental 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 data on halogen concentrations 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.

EPA selected these nine companies to provide supplemental information because EPA became aware that these companies may be testing, piloting or otherwise investigating new wastewater treatment technologies and EPA was unable to obtain information about these studies on a voluntary basis. After receiving each company's response, EPA met with these companies to discuss the FGD-related data they 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. EPA used this information to learn more about the performance of new treatment systems, inform the development of FGD wastewater limitations, learn more about plant-specific halogen usage (such as bromide), and obtain information useful for updating cost estimates for installing candidate treatment technologies. As needed, 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, EPA invited seven steam electric power plants 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. EPA asked plants to provide analytical data for ash impoundment effluent and untreated BA transport water (*i.e.,* ash impoundment influent). EPA selected the plants 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 plants 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 eliminate wastestreams or remove pollutants from them. Following the 2015 rule, and prior to the final rule, EPA reviewed 46 reports published between 2011 and 2020 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. These EPRI reports include those cited by EPRI in their comments on the proposed rule. 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, 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

[10] At proposal, EPA referred exclusively to one specific vendor's compact submerged conveyor technology (submerged grinder conveyors), but is using the more generic term for the technology (compact submerged conveyors) for this final rule because the Agency did not intend to limit its consideration to only one vendor's technology.

[11] In one case this preliminary information was provided by a membrane vendor and in the other the information was provided by a state permitting authority.

cooperatives, and community-owned utilities, respectively. EPA also met with the Utility Water Act Group (UWAG), an association comprising the trade associations above as well as individual electric utilities. EPA met with each of these trade associations separately and together to discuss the technologies and the analyses presented in the 2015 rule and receive information related to reconsidering the 2015 rule. EPA used information from these meetings to update industry profile data (*i.e.,* accounting for retirements, fuel conversions, and updated treatment technology installations). EPA also met with UWAG and EEI to discuss their comments with them after the close of the 2019 proposed rule comment period.

B. Information From the Drinking Water Utility Industry and States

EPA received additional information from the drinking water utility sector and states on the effects of bromide discharges from steam electric power plants on drinking water treatment processes. First, 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, EPA visited two drinking water treatment plants 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 plant. Finally, EPA obtained data on surface water bromide concentrations and data from drinking water monitoring from the two drinking water treatment plants. EPA also obtained existing state data from other drinking water treatment plants from the states of North Carolina and Virginia.

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

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

EPA gathered information on steam electric power plants 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). EPA used the 2017 and 2018 data to update the industry profile, including commissioning dates, energy sources, capacity, net generation, operating statuses, planned retirement dates, ownership, and pollution controls at the EGUs.

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. EPA also used the internet searches to identify or confirm reports of planned plant and EGU retirements, and reports of planned unit conversions to dry or closed-loop recycle ash handling systems. EPA used this information to inform the industry profile and identify process modifications occurring in the industry.

EPA received information from several environmental groups and other stakeholders following the 2015 rule. These groups provided examples of when, they believed, state permitting authorities had not properly implemented the ''as soon as possible date'' for the new, more stringent BAT requirements in the 2015 rule when issuing permits. EPA also met with these groups after the close of the comment period of the 2019 proposed rule to discuss those organizations' comments.

VII. Final Regulation

A. Description of the Main BAT/PSES Options

EPA analyzed four regulatory options at proposal, the details of which were discussed in the proposed rule (84 FR 64620). For the final rule, EPA evaluated four regulatory options, as shown in Table VII–1. Proposed regulatory options 1, 2, 3, and 4 correspond generally to regulatory options D, A, B, and C in this final rule, respectively, but contain certain differences, as detailed below. Public commenters generally supported three of the regulatory options that EPA proposed, or variants thereof.[12] The availability and achievability of technologies with better pollutant removals, as well as the general lack of public comments supporting proposed regulatory option 1, led EPA to focus updates to the Agency's analysis on the remaining three regulatory options. EPA did not update the analyses for regulatory option D, but rather retained the results of the proposed rule analysis for this option.

EPA is finalizing Option A in the final rule. All four options include the same technology bases for BA transport water, except Option A, which includes a different technology basis for the subcategorized low utilization EGUs and surface impoundments for EGUs permanently ceasing combustion of coal by 2028. In regards to FGD wastewater, Option D is based on chemical precipitation, Options A and B are based on a combination of chemical precipitation and low hydraulic residence time biological treatment, while Option C is based on membrane filtration; the difference between Options A and B is that the former includes three subcategories while the latter does not. Table VII–1 below summarizes the regulatory options considered in this rulemaking. The subcategories identified below are described further in Section VII.C, below.

[12] Some commenters also supported retaining the 2015 rule.

TABLE VII–1—MAIN REGULATORY OPTIONS

Wastestream	Subcategory	Technology basis for the BAT/PSES regulatory options			
		D	A (final rule)	B	C
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 plants	NS	Chemical precipitation	NS	NS.
	Low utilization EGUs	NS	Chemical precipitation	NS	NS.
	EGUs permanently ceasing the combustion of coal by 2028.	NS	Surface impoundments.	NS	NS.
FGD Wastewater Voluntary Incentives Program (Direct Dischargers Only)					
BA Transport Water	N/A	High recycle rate systems.	High recycle rate systems.	High recycle rate systems.	High recycle rate systems.
	Low utilization EGUs	NS	Surface impoundments +BMP plan.	NS	NS.
	EGUs permanently ceasing the combustion of coal by 2028.	NS	Surface impoundments.	NS	NS.

NS = Not Subcategorized.
Note: The table above does not present subcategories included in the 2015 rule because EPA did not reopen the subcategorization of oil-fired units or units with a nameplate capacity of 50 MW or less.

1. FGD Wastewater

Under Option D, EPA would establish BAT limitations and PSES for mercury and arsenic based on chemical precipitation. Under Options A and B, EPA would establish BAT limitations and PSES for mercury, arsenic, selenium, and nitrate/nitrite based on chemical precipitation followed by LRTR and ultrafiltration. Option A contains three subcategories. The first subcategory under Option A is for plants with high FGD flows (defined as greater than four MGD). For these plants, Option A would establish limitations and standards for mercury and arsenic based on chemical precipitation. The second subcategory under Option A is for low utilization boilers with a capacity utilization rating (CUR) of less than 10 percent per year. This is a change from the proposed subcategory, which was based on a cutoff of 876,000 MWh utilization. For those low utilization EGUs, Option A would require mercury and arsenic limitations based on chemical precipitation.[13] The third subcategory under Option A is for EGUs permanently ceasing the combustion of coal by December 31, 2028. This is a change from the proposed subcategory, which only included EGUs retiring by December 31, 2028. For this subcategory of EGUs, Option A would establish BAT limitations equal to BPT limitations for TSS based on the use of surface impoundments with a best management plan for minimizing discharges. For Options A, B, and D, EPA would establish voluntary incentives program limitations for mercury, arsenic, selenium, nitrate-nitrite, bromide, and TDS based on membrane filtration preceded by pretreatment (*i.e.,* chemical precipitation).[14] For Option C, EPA would establish BAT limitations and PSES for mercury, arsenic, selenium, nitrate/nitrite, bromide, and TDS based on membrane filtration, which would be applicable to all steam electric power plants (except if they qualify for the subcategories contained in the 2015 rule). For Options B and C, the final rule preamble evaluates alternative technology bases for all units to address comments that the proposed rule preamble did not evaluate technology alternatives for high flow plants, retiring units, or repowering units.

2. BA Transport Water

Under all options described above, the final rule controls the 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 that periodically discharges (purges) a small portion of the process wastewater from its system. This is a correction of the proposal, in which the Agency in some instances identified ‘‘dry handling or high recycle rate systems’’ as the proposed technology basis. While plants are free to use dry handling technologies to achieve the limitations in the rule, the final rule limitations are based on high recycle rate systems (as were the proposed limitations).[15] The only difference between Options A through D for BA transport water is that Option A includes two subcategories. The first subcategory under Option A is for low utilization EGUs with a CUR of less than 10 percent per year. This is a change

[13] As explained above, EPA did not propose to revise BAT limitations or PSES for oil-fired EGUs and/or small EGUs (50 MW or smaller).

[14] The proposal relied on data from three data sets to establish limits for the VIP membrane technology—two using chemical precipitation as the pretreatment technology for a portion of the pilot and one using chemical precipitation as the pretreatment for some portions of the pilot and only microfiltration for other portions of the pilot. However, the cost estimates for membrane filtration technology at proposal were based on microfiltration (or comparable large particle filter) pretreatment technology for plants without existing FGD wastewater treatment, which is less costly than chemical precipitation. The final rule limits are based entirely on those data using chemical precipitation pretreatment, and the final rule costs are also based on chemical precipitation as pretreatment. See Section XIII for further discussion on the use of data to establish limits.

[15] Public comments focused on the appropriateness of high recycle rate systems and did not discuss or recommend dry handling or other zero discharge systems as the technology basis, which is consistent with EPA's intent that the technology basis be high recycle rate systems alone, rather than include dry handling or high recycle rate systems.

from the proposed subcategory which was based on a cutoff at 876,000 MWh utilization. For these low utilization EGUs, Option A would establish BAT limitations for BA transport water equal to the BPT limitations based on gravity settling in surface impoundments to remove TSS.[16] Such plants would also 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 analyses, see Section VII(C) of the 2015 rule preamble.

The second subcategory under Option A is for EGUs permanently ceasing the combustion of coal by December 31, 2028. This is a change from the proposed subcategory, which only included retiring EGUs. For this subcategory of EGUs in Option A, EPA would establish BAT limitations equal to BPT limitations for TSS, based on gravity settling in surface impoundments. For Options B and C, EPA evaluated high recycle rate systems for all units to address comments that technology options should have considered alternatives for retiring units or repowering units. This is a change from the original regulatory options presented at proposal.

Finally, EPA is not finalizing the proposed definitional change to exclude water remaining in a tank-based high recycle rate system when the plant permanently ceases coal combustion. Instead, facilities with high recycle rate systems may properly discharge this water as BA purge water subject to the BPJ limits established by the permitting authority, as discussed in section XIV(A)(2) of this preamble.

B. Rationale for the Final 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), EPA is establishing BAT effluent limitations based on the technologies described in Option A. EPA's selection of the generally applicable BAT (LRTR plus chemical precipitation for FGD wastewater and high recycle rate for BA transport water) in Option A is independently supported by this rulemaking record and not dependent upon the subcategories that are also included in Option A.[17] EPA's rationale for the final rule's limitations are discussed below. EPA is not finalizing the bromide sub-options proposed in 2019 and, as a result, this section does not include discussion of those sub-options. A more complete discussion of site-specific water quality-based effluent limitations for bromides provided in Section XIV(C) of this preamble.

1. FGD Wastewater

This final rule 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. More specifically, the technology basis for BAT includes the same chemical precipitation system described in the 2015 rule, which employs equalization, hydroxide and organosulfide precipitation, iron coprecipitation, and removal of suspended and precipitated solids. This chemical precipitation system is followed by a low hydraulic residence time, anoxic/anaerobic biological treatment system designed to remove heavy metals, selenium, and nitrate-nitrite.[18] The LRTR bioreactor stage is followed by ultrafiltration to remove suspended solids, including colloidal particles, exiting the bioreactor.

Both chemical precipitation and biological treatment are well-demonstrated technologies that are available to steam electric power plants for use in treating FGD wastewater. In addition to the 39 plants using chemical precipitation that were mentioned in the 2015 rule preamble, plants have installed, or have begun installation, of such systems, and have taken steps to cease using surface impoundments to treat their FGD wastewater. This trend is expected to continue in response to the April 11, 2021 cease receipt of waste date in the CCR Part A final rule. In addition, thousands of industrial plants nationwide have used chemical precipitation for the last several decades, as described in the 2015 rule record. Ultrafilters downstream of the biological treatment stage are designed to remove suspended solids—*i.e.,* any reduced, insoluble selenium, mercury, or other particulates—exiting the bioreactor. 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 filtration technology (which uses nanofiltration or reverse osmosis). Membrane filtration is the basis for Option C and the VIP under Options A and B, and is designed to remove dissolved metals and inorganics (*e.g.,* nutrients, bromides, etc.). Unlike the nanofiltration and reverse osmosis technologies included as the technology in Option C and the VIP, ultrafilters do not generate a brine that would require encapsulation with FA or other disposal techniques. The types and quantities of solids removed by the ultrafilter in the CP+LRTR treatment system are similar to the particulates captured in other multimedia filters (*e.g.,* sand filters), or settled out in HRTR or surface-impoundment-based systems with longer residence times. These systems do not result in the same non-water quality environmental impacts that are associated with the brine generated by the membrane filtration technology.

After accounting for the changes in the industry described in Section V of this preamble, at the time *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule* (DCN SE08688) was developed 15 steam electric power plants with wet scrubbers that discharge FGD wastewater are expected to already have technologies in place that can meet the final BAT effluent limitations for FGD wastewater.[19] Of these 15 plants, seven are currently operating anoxic/anaerobic biological treatment designed to substantially reduce nitrogen compounds and selenium in their FGD wastewater. These biological treatment

[16] Although TSS is a conventional pollutant, regulation of TSS in this final rule is intended as regulation of the particulate form of toxic metals through the use of an indicator pollutant.

[17] If any provisions of this rule are reviewed and vacated by a court, it is EPA's intent that as many portions of this rule remain in effect as possible.

[18] Similar to the 2015 rule and consistent with discussions with engineering firms and plant staff, EPA assumed that in order to meet the limitations and standards, plants 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 5.2.1 of the Supplemental TDD.

[19] Two plants will retire or cease burning coal prior to 2028. The remaining 13 plants represent 14 percent of steam electric power plants with wet scrubbers. EPA notes that 35 percent of all steam electric power plants with wet scrubbers use FGD wastewater management approaches that eliminate the discharge of FGD wastewater altogether. But, although these technologies (described above in Section V.C.1) may be available to some plants, none of them are available nationwide, and thus do not form the basis for the final BAT limitation. For example, evaporation impoundments are only practical in certain climates. Similarly, complete recycle FGD systems are only available at plants with appropriate FGD metallurgy. Facility conditions and availability of these technologies have not materially changed since the 2015 rule, and EPA thus reaffirms that these technologies are not available nationwide and are not a basis for the final BAT limitations.

systems are a mix of low and high hydraulic residence time.[20] EPA identified an eighth plant that previously operated an anoxic/anaerobic biological treatment system, but more recently installed a thermal system for the treatment of FGD wastewater. See DCN SE08964. A ninth plant is also operating an anoxic/anaerobic biological treatment system, but is expected to retire all generating units by 2028. Another six steam electric power plants are operating thermal treatment systems for FGD wastewater; one of these is expected to retire all generating units by 2028.

In the 2015 rule, EPA rejected three availability arguments made against biological treatment. EPA solicited comment on retaining its 2015 findings concerning biological treatment, and no new information was provided by commenters suggesting that EPA's 2015 analysis was incorrect. Instead, EPA has continued to confirm its prior findings concerning the availability of biological treatment. First, EPA rejected the argument that maintaining a biological system over the long run is infeasible. Of the nine full-scale systems mentioned above, three plants have used the biological technology for more than a decade, with varying operating conditions, climate conditions, and coal sources, to treat FGD wastewater. Many pilot tests of the biological technology have been conducted at various plants, and data from these tests demonstrate that, even in the face of major upsets during chemical precipitation, the biological stage continues to reduce selenium and nitrogen.

In the 2015 rule, EPA also rejected the argument that selenium removal efficacy is subject to the type of coal burned and coal-switching. Plants have continued to operate biological treatment systems while switching coals and, in those cases, have maintained selenium removal. Furthermore, at least three pilot- and one full-scale system have now been successfully run or installed to treat FGD wastewater at plants burning subbituminous coals or blends of bituminous and subbituminous coals, encompassing both HRTR and LRTR technologies.

Finally, in the 2015 rule, EPA rejected arguments that cycling plants up and down in production, and even out of service for various periods of time, would affect the ability of plants to meet the effluent limitations. Industry provided data for two plants 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 CP+HRTR and CP+LRTR technologies, EPA is establishing BAT based on the CP+LRTR technologies rather than the CP+HRTR technologies. Some commenters pointed out that CP+HRTR technologies are still available and economically achievable,[21] and argued that EPA is thus obligated to select CP+HRTR. EPA agrees that CP+HRTR continues to be available and economically achievable; however, after considering the statutory factors in section 304 of the CWA (as EPA is required to do), EPA does not find that CP+HRTR is the *Best* Available Technology Economically Achievable. CP+LRTR pollutant reductions are comparable to CP+HRTR pollutant reductions,[22] are less costly, and require significantly less process or plant footprint modifications than the CP+HRTR option.

As explained in Section XIII of this preamble, the long-term averages forming the basis of the selenium limitations for CP+LRTR and CP+HRTR are similar, and the higher selenium limitations for the CP+LRTR systems are largely driven by increased short-term variability around that average, rather than a meaningful difference in long-term pollutant removals.[23] Some commenters argued that CP+LRTR pollutant reductions are not comparable to HRTR pollutant reductions. EPA disagrees with these commenters and rejects this characterization for several reasons. First, these comments appear to be limited to a single pollutant: Selenium. When comparing the limitations of all four regulated pollutants (mercury, arsenic, selenium, and nitrate/nitrite) in the 2015 rule to this final rule, some limitations are more stringent, while others are less stringent.[24] Some commenters expected the limitations and long-term averages for all constituents to be less stringent with CP+LRTR as compared to CP+HRTR due to the shorter residence time. This is not the case. Indeed, some limitations become more stringent due, in part, to the different design of CP+LRTR systems, which include ultrafiltration in the prefabricated systems delivered for pilot studies and full-scale installations to date.[25] Thus, to the extent that commenters relied on the limitations and long-term averages to make this argument, EPA concludes it is reasonable and allowed by the Act to consider removals as a whole, which results in comparable removals for the suite of pollutants in FGD wastewater discharges.

Second, even taking selenium in isolation, EPA disagrees that a simple comparison of numeric limitations and long-term averages is the only way to identify pollutant removals attainable through the application of BAT. It can be misleading to look at the numeric limitations in isolation. Instead, EPA has considered pollutant concentrations in treated effluent as compared to those in raw FGD wastewater. In the 2015 rule TDD, EPA estimated the average selenium concentration in untreated FGD wastewater as 3,130 ug/L. Using this for comparison demonstrates that both the CP+LRTR and CP+HRTR treatment trains remove more than 99 percent of selenium initially present in FGD wastewater. Even were EPA to examine incremental removals, when compared to the performance of surface impoundments under existing BPT regulations, both treatment trains would remove more than 99 percent of the selenium remaining after physical settling. EPA also notes that both the long-term average and the actual limitations for selenium in this final rule are more stringent than they were in the proposed rule. In summary, CP+LRTR and CP+HRTR are two very effective selenium removal technologies. Between these two, EPA selected as BAT the technology that is also less costly and requires significantly less modification of a plant's process or footprint.

[20] In addition to these seven plants, some plants employ other types of biological treatment. Some of these systems are sequencing batch reactors (SBR), which treat nitrogen and can be operated to remove selenium. The SBR systems currently operating at steam electric power plants, however, would likely not be able to meet the limitations discussed in the final rule without reconfiguration.

[21] Without support, some commenters also suggested that CP+LRTR and CP+HRTR are the same technologies. A more detailed response is provided in *Response to Public Comments for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (DCN SE08615).

[22] For example, while the effluent from CP+LRTR is more variable than from CP+HRTR, both technologies achieve long-term average effluent concentrations for selenium lower than 20 mg/L.

[23] 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 [. . .]'').

[24] While these four indicator pollutants are regulated, the record for the 2015 rule and current final rule both indicate reductions in many other pollutants.

[25] To the extent that limits become more stringent due to the use of data from pilot studies with chemical precipitation systems designed to meet the 2015 rule limits prior to the biological treatment components, CP+HRTR limits would also be expected to become more stringent to some extent.

CP+LRTR is less costly than the CP+HRTR technology selected as the BAT basis of the 2015 rule. Compared to the baseline of the 2015 rule, CP+LRTR is estimated to save approximately $52 million per year in after-tax costs to industry [26] While the CP+HRTR costs are economically achievable, EPA finds those costs unreasonable for a treatment technology that would result in marginal additional reductions in selenium and that would result in marginal increases in other pollutants, such as mercury.

CP+LRTR requires fewer process changes than CP+HRTR. Compared to HRTR, LRTR installations are less complex and require fewer modifications to a plant's footprint. The HRTR systems used as the basis for BAT 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, and require little more than a concrete foundation, electricity supply, and piping connections. For further public comments and responses regarding HRTR and LRTR, see DCN SE08615.

a. Membrane Filtration

Except for plants participating in the VIP discussed below, the final rule does not establish BAT limitations based on membrane filtration (Option C). EPA received many comments arguing both in favor and against the use of membrane filtration as BAT for treatment of FGD wastewater, including comments on the technology's availability, costs, economic achievability, and non-water quality environmental impacts. With respect to availability, some commenters argued that the technology is available, citing pilot studies, three full-scale foreign installations,[27] use in other industrial sectors, and vendor claims of product performance. Other commenters argued that this technology is not available due to uncertainties regarding the extent of pretreatment required to ensure reliable treatment performance and management of the resulting brine. With respect to costs, some commenters argued that costs were overestimated due to decreasing EGU use, resulting in reduced flow volumes that require treatment; while other commenters argued that costs were underestimated due to incomplete pretreatment costs (*e.g.,* microfiltration rather than full chemical softening), failure to analyze costs using maximum design flows, missing cost components, and underestimated ash needs for brine management. With respect to economic achievability, some commenters pointed to uncertainties about the costs and asserted that membrane filtration would not be economically available for some plants. Finally, with respect to non-water quality environmental impacts, some commenters argued that many plants currently make beneficial use of some or all of their FA (a practice that could be hindered if plants use membrane filtration); while other commenters argued that beneficial use of FA would not be affected by use of membrane filtration and that EPA failed to evaluate alternative brine management methods.

As the summary of comments presented above makes clear, EPA received a wide range of comments on membrane filtration technology. After carefully considering the statutory factors for BAT and available data, EPA is rejecting membrane filtration as BAT. First, based on significant information gaps and uncertainties in EPA's record, EPA cannot conclude that membrane filtration is technologically available nationwide, as required by the CWA. Second, the Agency finds that, on a nationwide basis, membrane filtration entails unacceptable non-water quality environmental impacts associated with management of the membranes' byproduct, brine. Finally, while the factors above are sufficient to reject membrane filtration as BAT, EPA also notes that membrane filtration would result in higher costs to industry.

At the time of the 2015 rule, EPA had no record of information about membrane filtration technologies. Since that time, 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 technologies generate both a treated effluent and a residual wastestream that requires further treatment or disposal. Microfiltration and ultrafiltration generate a solid waste residual, which is disposed of. Nanofiltration, reverse osmosis, forward osmosis, and EDR all produce a concentrated brine residual which must be disposed of. At proposal, EPA considered nanofiltration, reverse osmosis, forward osmosis, and EDR membranes and proposed effluent limitations for the VIP option based specifically on a combination of microfiltration and reverse osmosis membrane technologies.

Other industries use a variety of different types of membrane filtration technologies. EPA met with vendors that have installed membrane systems in several industries, including textiles,[28] chemical manufacturing,[29] mining,[30] and agriculture.[31] Within the steam electric power generation industry, reverse osmosis membranes are a technology used for treating EGU makeup water and cooling tower blowdown, and EDR membranes are a technology used for treating ash impoundment discharges.[32] Nevertheless, it cannot be assumed that membrane filtration technology is transferable, and the information presented below demonstrates that, despite its use in other industries, there may be technical issues constraining its use for treating FGD wastewater.

EPA's record demonstrates that no domestic steam electric power plants have installed full-scale nanofiltration, reverse osmosis, or EDR membrane filtration systems to remove dissolved pollutants in FGD wastewater.[33] A vendor email cited by some commenters erroneously asserted that a full-scale installation of such a technology had begun at Georgia Power's Plant Scherer. Follow-up discussions with staff working on that project revealed that the plant is not installing a permanent full-scale membrane technology to treat FGD wastewater, but is performing a long-term pilot of both membrane filtration and biological treatment systems to

[26] Due to the final rule's changed compliance dates, this estimate also includes discounting which may overstate the savings.

[27] The record at proposal included three full-scale foreign installations.

[28] ERG. 2020. Final Notes from Call with Dupont. DCN SE08618.

[29] ERG. 2020. Final Notes from Call with Dupont. DCN SE08618.

[30] ERG. 2019. Final Notes from Meeting with Pall Water. (5 March). EPA–HQ–OW–2009–0819–7613; Wolkersdorfer, Christian *et al.* 2015. Intelligent mine water treatment—recent international developments. (21 July). DCN SE08581; U.S. EPA. 2014. Office of Superfund and Remediation and Technology Innovation. Reference Guide to Treatment Technologies for Mining-Influenced Water. EPA 542–R–14–001. (March). DCN SE08582.

[31] CH2M Hill. 2010. Review of Available Technologies for the Removal of Selenium from Water. (June). DCN SE08583.

[32] EPRI (Electric Power Research Institute). 2015. *State of Knowledge: Power Plant Wastewater Treatment—Membrane Technologies.* August. 3002002143.

[33] Ultrafiltration has been installed as part of several FGD wastewater treatment systems in the U.S. and is included as a back-end component of the CP+LRTR BAT established in this final rule; however, these membranes are only capable of removing suspended solids, not dissolved pollutants.

evaluate possible compliance alternatives under planned future changes to the plant (see DCN SE08619). The State of Maryland also informed EPA that three GenOn plants planned to install technologies to meet the 2015 rule VIP effluent limitations. In a teleconference call held to learn more about these plans, GenOn staff stated that one of these plants (Dickerson) had announced its retirement, but confirmed that the other two (Chalk Point and Morgantown) are currently considering reverse osmosis systems (see DCN SE08614).[34] EPA views GenOn's consideration of membrane technology similarly to the bids and engineering reports for full-scale systems that the agency was aware of at proposal. As discussed at proposal, the sources of the bids and engineering reports expressed concerns about operating a technology on this wastewater that would be the first of its kind in the U.S. While bids, engineering reports, and one company considering potential membrane installations are important considerations in evaluating the availability of a technology, they do not demonstrate that the technology is available under the CWA. Because no full-scale membrane filtration system for treatment of FGD wastewater is yet operating domestically, EPA carefully considered available data from pilots, foreign installations, and other industries.

With respect to pilots, EPA is aware of at least 19 previous or ongoing domestic pilot studies and one foreign pilot study of FGD wastewater treatment using four different membrane filtration technologies.[35] All of these technologies first used some form of suspended solids removal, such as microfiltration or chemical precipitation. This pretreated FGD wastewater was then fed into either nanofiltration, reverse osmosis, or EDR membrane filtration systems. 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.[36]

EPA is aware of 12 foreign installations: One in South Korea, one in Finland, and 10 in China. EPA's rulemaking record contains very limited information about these plants. When EPA contacted Doosan about its system in South Korea, the company declined to share plant operation, maintenance, or performance information, and indicated that it was not interested in the U.S. market. Similarly, EPA contacted Lenntech regarding its system in Finland, but has received no information about this plant's operation, maintenance, or performance.

Regarding the plants in China, EPA is generally aware that two of the plants employ pretreatment and a combination of reverse osmosis and forward osmosis. But EPA was not able to obtain further information about the specific configurations, maintenance, or long-term performance of these two systems.[37] EPA also has no information about how the resultant brine is being managed or disposed of. Furthermore, the company that sold these two systems has since ceased commercial operations.[38] EPA is aware that two other plants operating in China employ pretreatment followed by nanofiltration and reverse osmosis. As with the systems above, the vendors declined to provide plant operation, maintenance, or performance information to EPA. The remaining Chinese systems were developed by DuPont, which met with EPA after proposal to provide what limited information was available. While DuPont has sold six systems to Chinese plants to treat FGD wastewater, the company did not have access to operation, maintenance, or performance data for these systems.

Due to travel restrictions in place during the COVID–19 pandemic in spring and summer 2020, EPA representatives were unable to travel abroad to visit these plants. Because the vendor companies either ceased operations or declined to provide EPA with information about the operation, maintenance, or performance of their membrane filtration products, and EPA's lack of regulatory authority to compel the production of information from foreign plants, EPA's record has significant information gaps on the operation and performance of membranes used to treat FGD wastewater.

With respect to the use of membrane filtration in other industries and in connection with non-FGD power plant wastestreams, given what is known about FGD wastewater, EPA focused its evaluation on the more challenging wastewaters in other industries. In the mining industry, reverse osmosis is employed to treat mine-influenced water. For example, since 2006, the Bingham Canyon Water Treatment Plant (BCWTP) at the Kennecott South Superfund site treats 3,200 gallons per minute of mine-influenced water and has maintained a TDS removal efficiency of 98.9 percent, given an expected influent TDS of approximately 2,000 mg/L.[39] Mining wastewaters demonstrate some similar challenges seen in FGD wastewaters, but there are also differences in the two wastestreams. For example, both are highly scaling in gypsum,[40] but as the BCWTP example demonstrates, mining influent TDS concentrations can be an order of magnitude (or more) lower than the TDS concentrations found in some FGD wastewater streams.[41] In the mining industry, brine generated by reverse osmosis is typically disposed of through evaporation, deep well injection, or ocean discharge.[42]

In the oil and gas industry, there are several applications and opportunities for membrane filtration, recently summarized by Adham et al. (2018).[43] For example, nanofiltration is used worldwide for sulfate removal in offshore oil and gas operations. Reverse osmosis is the standard treatment for coal seam gas water in Australia, where regulations restrict underground

[34] The company indicated that plans for both units will depend on the requirements of this final rule, and also, for one of its units, changing electricity demand.

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

[36] The record includes additional encapsulation studies and data not explicitly linked to these 19 pilots.

[37] 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.

[38] DCN SE08034 contains a story summarizing the forward osmosis company Oasys ceasing commercial operations.

[39] U.S. EPA (Environmental Protection Agency). 2014. *Reference Guide to Treatment Technologies for Mining-Influenced Water.* EPA 542–R–14–001. Office of Superfund Remediation and Technology Innovation. March. Available online at: *https://clu-in.org/download/issues/mining/Reference_Guide_to_Treatment_Technologies_for_MIW.pdf* (DCN SE09084).

[40] Patel, S. 2020. Rethinking Wastewater Treatment for Better FGD Economics. *Power Magazine.* May 31. Available online at: *https://www.powermag.com/rethinking-wastewater-treatment-for-better-fgd-economics/ (DCN SE09085).*

[41] The FGD wastewater treatment system pilot tests that were highlighted in the petitions for reconsideration of this rule illustrate this point. EPRI. 2017. *Biological Treatment of Flue Gas Desulfurization Wastewater at a Power Plant Burning Powder River Basin Coal—Pilot Demonstration with the ABMet Technology.* EPA–HW–OW–2009–0819–6480.2.

[42] U.S. EPA (Environmental Protection Agency). 2014. *Reference Guide to Treatment Technologies for Mining-Influenced Water.* EPA 542–R–14–001. Office of Superfund Remediation and Technology Innovation. March. Available online at: *https://clu-in.org/download/issues/mining/Reference_Guide_to_Treatment_Technologies_for_MIW.pdf (DCN SE09084).*

[43] Adham, S., Hussain, A., Minier-Matar, J., Janson, A., Sharma, R. 2018. *Membrane applications and opportunities for water management in the oil and gas industry. Desalination.* 440. 2–17. Available online at: *https://www.sciencedirect.com/science/article/pii/S0011916417321380 (DCN SE09087).*

injection. Reverse osmosis is also a standard treatment for desalination (*i.e.,* TDS removal) in this industry. In contrast to the uses for mining wastewaters discussed above, the oil and gas industry's use of membranes typically involves wastewaters with TDS concentrations at least as high as those found in FGD wastewater, but with different scaling potential. Within the oil and gas industry, underground injection, evaporation, and ocean discharge are common disposal methods for the resulting brine.

Membrane filtration technologies are also employed for other, non-FGD wastestreams at steam electric power plants. Reverse osmosis is a generally accepted, standard practice for treating EGU makeup water at steam electric power plants.[44] EGU makeup water is often treated groundwater or surface water which would, therefore, not have TDS or scaling potential similar to FGD wastewater. Reverse osmosis has also been used to treat cooling tower blowdown at several coal-fired and non-coal-fired steam electric power plants. According to one reverse osmosis technology vendor, cooling tower blowdown has similar scaling potential to FGD wastewater. EPA does not have information in this record to either confirm this statement or to extrapolate this finding to the industry more broadly; however, scaling is a known issue for cooling tower water, which is ultimately blown down.[45] The vendor that made this statement sold the system, comprising microfiltration followed by reverse osmosis, to a plant to treat high TDS cooling tower blowdown that was corroding its brine concentrators (thermal systems). This membrane filtration system was able to replace the brine concentrators, resulting in a reduction of parasitic load in cooling tower blowdown and substantial cost savings.[46] Finally, EDR has also been used at a power plant in South Korea to treat ash transport water for further use as FGD makeup water.[47] While ash transport water can have high variability, there is no information in the record suggesting that ash transport water has scaling potential or TDS concentrations similar to FGD wastewater.

After evaluating all available information on membrane filtration, EPA has concluded that critical uncertainties remain regarding operation of the suite of membrane filtration technologies that the Agency evaluated as the basis for Option C. With respect to data from the pilot studies, these studies focused on membrane technologies intended to remove dissolved pollutants. Several studies of the technologies designed to remove dissolved pollutants 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 that they would consider installing to 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. Both of these limitations prevented 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. The pilot tests, for which 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. EPA, however, 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 plants using a single vendor's reverse osmosis technology.[48] EPA further finds that use of data from treatment of non-FGD wastewaters in this and other industries would not be appropriate because the other wastewaters that are currently being treated by membrane filtration systems at full scale differ in variability, scaling potential, TDS, or a combination thereof.

Some commenters argue that certain data limitations are not sufficient to reject membrane filtration systems as BAT for FGD wastewater because such systems can be operated as no discharge systems. EPA agrees that membrane filtration systems can be operated as no discharge systems; however, due to the significant data gaps in the record, EPA cannot conclude that such systems can operate continuously as no discharge systems for FGD wastewater, nor that they can operate as no-discharge systems on FGD wastewater in all cases, nor that their continuous operation would not result in other unacceptable non-water quality impacts. Staff working on one current membrane filtration pilot indicated that, with additional flexibility to reuse membrane filtration permeate as EGU makeup water, the plant may consider a no-discharge alternative in the future. At present, however, the pilot is being conducted to determine the feasibility of operating a membrane filtration system with a discharge, including the evaluation of pretreatment and post-treatment to comply with the proposed VIP mercury limitations. Similarly, while GenOn indicated that it is considering installing membrane filtration systems that would recirculate permeate as a no discharge system, GenOn acknowledged that at least some discharges would eventually be necessary, for example when the EGU is not operating or is being retired.

While the limited information in EPA's record on foreign installations may suggest that these systems operate as no-discharge systems, EPA does not have information on these systems' long-term performance to confirm that they continually operate as no-discharge systems, whether there are some periods during which discharges occur, or whether their operation may result in other unacceptable non-water quality impacts. Furthermore, the information that EPA does possess on foreign installations indicates that pretreatment before membrane filtration is a challenge due to FGD wastewater

[44] EPRI (Electric Power Research Institute). 2015. *State of Knowledge: Power Plant Wastewater Treatment—Membrane Technologies.* August. 3002002143.

[45] Daniels, D.G. 2015. Winning the Cooling Tower Trifecta: Controlling Corrosion, Scale, and Microbiological Fouling. *Power Magazine.* August 21. Available online at: *https://www.powermag.com/winning-the-cooling-tower-trifecta-controlling-corrosion-scale-and-aqmicrobiological-fouling/* (DCN SE09088).

[46] Drake, M., Wise, S., Charan, N., and Venkatadri, R. 2012. ZLD Treatment of Cooling Tower Blowdown with Membranes. *WaterWorld.* December. Available online at: *https://www.watertechonline.com/process-water/article/16211541/zld-treatment-of-cooling-tower-blowdown-with-membranes (DCN SE09089).*

[47] *https://www.ge.com/in/sites/www.ge.com.in/files/GE_solves_ash%20pond_capacity_issue.pdf (DCN SE09090).*

[48] These three data sets served as the basis of the final 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 in FGD wastewater. Additional pilots, tests, and data collection could result in these technologies becoming available by the VIP compliance date of 2028; however, the VIP compliance date is not based on an assumption that the technology will be available by 2028.

variability. This is consistent with the public comments received on the proposal, as well as the main focus of the long-term pilot at Plant Scherer. In contrast to the thermal system that EPA visited in Italy before the 2015 rule (and where EPA took samples and discussed the system with experienced engineers), EPA does not have access to the Chinese plants to resolve some of the critical unanswered questions discussed above.

Supplementing what is known about pilot studies and foreign plants with information about the use of membrane filtration on non-FGD wastestreams in this and other industries still does not address or resolve the uncertainties in EPA's record. Although EPA acknowledges that some of the other wastewaters discussed above are subject to operational variability, scaling potential, and high levels of TDS, the unique combination of these factors present in steam electric FGD wastewater favors EPA's conclusion that membrane filtration is not available for treatment of FGD wastewater at all plants in the steam electric power generating industry.[49] Nevertheless, like evaporation-based and thermal treatment technologies, FGD wastewater may be amenable to treatment with membrane filtration technologies in at least some circumstances. Thus, EPA's conclusion that membranes are not available nationwide, as required under the CWA, does not conflict with EPA's finding that membrane filtration may be available at specific sites for purposes of the VIP.

EPA also rejects membranes as the technology basis for BAT for all existing plants because it could discourage more valuable forms of beneficial reuse of FA (such as replacing Portland cement in concrete), causing more FA to be disposed of as waste.[50] While EPA agrees with comments that there may be several alternative ways to treat or dispose of the brine generated by membrane filtration, as discussed further below, plants are most likely to encapsulate the brine with FA and lime and dispose of the resulting solid in a landfill.

In concluding that the selection of membranes as BAT would result in unacceptable non-water quality environmental impacts, EPA evaluated brine management alternatives that were discussed with domestic plants employing thermal systems, foreign plants employing membrane filtration systems, and domestic plants in other industries employing membrane filtration systems.[51] EPA also evaluated whether FA is being disposed of or is being sold and productively reused. After careful review of the information in the record for this rulemaking, EPA projects that, in the United States, the least cost option if membrane filtration were selected would be encapsulation with FA and lime and disposal of the resulting solid in a landfill. The following paragraphs summarize the evaluations which led to EPA's conclusion that there is an unacceptable non-water quality environmental impact in selecting membrane filtration systems as BAT.

There are no domestic plants operating membrane filtration systems for EPA to contact. EPA therefore contacted two domestic plants operating thermal FGD systems and examined information submitted to EPA's Region 1 regarding a third thermal FGD system. Thermal and membrane filtration systems generate similar brines, as both increase the concentration of TDS in FGD wastewater by removal of "clean" water. For the three domestic thermal systems treating FGD wastewater, the resultant brine is either used to condition (*i.e.,* wet) ash for disposal without encapsulation[52] or is crystallized and sent to a landfill. Thus, encapsulation of the brine using FA at these three plants is unnecessary. When asked about the availability of FA for sale, one of the three plants indicated that its particular market for FA is flush, and that plant was no longer able to maintain contracts for the sale of its FA, which would make it available for the plant to use to encapsulate the thermal system brine. In contrast, two of the plants with which EPA discussed possible future installations of membrane filtration systems stated that they sell 100 percent of the FA generated for beneficial reuse. Although some commenters suggested that there is more than sufficient FA available for reuse, the EPA's rulemaking record contains information to the contrary. According to 2017 and 2018 EIA data, the median percentage of FA that was sold for beneficial use by plants with wet FGD systems was approximately 14 percent, with some plants selling all of their fly ash and some plants selling none. Furthermore, these EIA estimates may be low, as one plant's staff represented that they were beneficially using 100 percent of their FA rather than the amount reported in the EIA data.[53] A quantitative comparison of EIA data for plants with FGD wastewater indicates that if plants currently disposing of their FA installed membrane filtration, they may have enough FA to encapsulate the quantities of brine produced by membrane filtration. Two assumptions underly EPA's comparison of EIA FA beneficial use and disposal data to FGD brine encapsulation. First, EPA assumes that the fraction of brine generated from all FGD wastewaters is the same at all plants that would install a membrane system. Second, it assumes that all plants that would install a membrane system would be able to make use of similar encapsulation blends as the bids and pilots which EPA reviewed. In practice, EPA expects the percent of brine generated by membrane systems to differ from plant to plant, based on FGD wastewater characteristics. EPA also expects the encapsulation blend to differ from plant to plant based on both the brine characteristics and the fly ash characteristics. This is consistent with public comments EPA received on the proposal. Thus, while EPA's assumption of a typical blend is reasonable for a nationwide assessment, the Agency anticipates that there will be sites where non-water quality environmental impacts are particularly unacceptable.[54]

But, while these assumptions are appropriate for nationwide cost estimates which are needed to demonstrate economic achievability for the industry as a whole, this does not necessarily mean that these assumptions should be used for analyzing the non-water quality environmental impacts associated with the resultant brine from membrane use, and in particular, estimating what plants are likely to do with this by-product in relation to available FA. Whether sufficient FA is present on site or available in the local market is a site-specific question. Should plants generate more brine than EPA estimated in its analysis, or should plants not have the quality of FA (*e.g.,* class C, class F) necessary for the

[49] While one membrane vendor commented that FGD wastewater is no different than any other industrial wastewater, it did not provide any data or analysis to support this statement.

[50] While EPA considers FA use for waste solidification and stabilization as beneficial use, the CCR waste being solidified or stabilized must still be disposed of in accordance with 40 CFR 257.

[51] EPA did not evaluate alternatives which would not be available to the industry (*e.g.,* unlike offshore oil and gas facilities, ocean discharge would not be available to inland power plants).

[52] Ash conditioning with water or surfactants is a standard industry practice to control fugitive dust emissions, and also a standard component of fugitive dust plans required under the CCR rule.

[53] EPA was unable to resolve the conflicting company-stated beneficial use rates at this plant with the plant-specific EIA data.

[54] While there may be some sites where these non-water quality environmental impacts are acceptable, the Agency has not identified either information or a consistent basis upon which to subcategorize these plants. In any case, such a subcategorization approach may still not address the availability concerns raised in the discussion above.

assumed blend, those plants would need to reduce the quantity of ash beneficially reused or acquire a substitute to encapsulate the brine byproduct of an installed membrane system.

Based on the limited available information, EPA understands that at least two foreign plants operating full-scale membrane systems send the resulting brine to a crystallizer to generate and sell a 95 percent high-purity industrial salt. However, there are too many uncertainties for EPA to estimate with confidence how many plants in the United States might be able do the same. EPA understands that these foreign plants engaged in negotiations with end-users prior to commissioning their membrane systems. At one example system, the plant generates and sells approximately 10,000 tons of industrial-grade salt per year. While a crystallizer would be a more expensive option than ash conditioning practiced at no-discharge plants in the U.S., the sale of industrial salt could generate additional revenue to offset those additional costs. Without salt revenue data from China, it is not possible to compare these specific scenarios either in terms of costs or non-water quality environmental impacts and any conclusions would be speculative and lack factual support in this rulemaking record. Furthermore, EPA cannot evaluate the practicality of such sales in the U.S. because the Agency does not know which industries are purchasing these salts, if these industries operate in the U.S., if they would be willing to purchase salts from the U.S., or what the specifications are for the salt product.

Finally, EPA examined brine management in other industries. In both the mining industry and in oil and gas, brine is managed through evaporation (including evaporation impoundments), deep well injection, and ocean discharge. Most steam electric power plants are not near enough to an ocean for ocean discharge to be a feasible alternative. Evaporation is more consistent with disposal methods at the domestic thermal and foreign membrane filtration plants discussed above. The use of evaporation impoundments is generally dependent upon climate and plant space, so not all steam electric power plants may be able to employ evaporation impoundments as is done at some mining and oil and gas establishments. However, crystallization is an evaporation means that is employed at some domestic and foreign plants to manage FGD wastewater brine. Finally, deep well injection is not known to be used at any steam electric power plants to manage FGD wastewater brine.

After consideration of the information above, EPA evaluated membrane filtration with three representative brine management alternatives to determine which could most likely represent future brine management. First, as it did for the proposed rule, EPA evaluated brine encapsulation with FA and lime, in a blend representative of the information in EPA's record.[55] Second, EPA conducted a sensitivity analysis which examined crystallization and disposal of the resultant salt.[56] Finally, EPA conducted a sensitivity analysis which examined deep well injection. While EPA received comments that the brine might be sold to oil and gas companies, commenters did not provide any examples where this is currently occurring, nor is the Agency aware of any. Thus, as it did for ocean discharge (see above), EPA concluded that direct sale of brine to oil and gas companies would not be representative of potential brine management in the steam electric power generating industry.

After conducting these three representative brine management analyses, EPA concludes that the method most likely to be employed by steam electric power plants using membrane filtration to treat FGD wastewater would be encapsulation with FA and lime for disposal of the resulting solid in a landfill. This brine management alternative was the least cost solution in the bids and engineering documents examined, was the least cost solution in EPA's own cost estimates, and is the disposal approach discussed by both Georgia Power[57] and GenOn[58] as their most likely procedure if theyose ultimately choose to participate in the VIP and install membrane filtration systems by the 2028 compliance date.

As described in the proposal, landfilling an encapsulated material raises challenges. For instance, comingling encapsulated material with other landfill refuse could result in a leachate blowout. The King County Landfill in Virginia experienced a leachate blowout 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 CCR 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.[59]

Moreover, instead of disposing of their FA, plants 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.[60]

Specifically, the Agency estimated (U.S. EPA 2011) that each ton of FA used as a substitute for Portland cement would avoid the use of 5,400 megajoules of nonrenewable energy, 690 liters of water use, 1,000,000 grams (g) of CO_2 emissions, 840 g of methane emissions, 1,400 g of CO emissions, 2,700 g of NO_X emissions, 2,500 g of SO_X 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.[61] After considering these cross-program environmental impacts, EPA finds that discouraging this beneficial use of FA on a nationwide basis would result in unacceptable non-water-quality

[55] This scenario is representative not only of that blend, but also of blends that would use more or less fly ash and/or lime, as well as less expensive ash conditioning, in which ash is wetted just with the brine (in lieu of other water or surfactants) prior to disposal.

[56] This scenario could also be representative of crystallization with sale of the resultant salt; however, EPA's rulemaking record lacks information with which to analyze potential sales.

[57] In discussions about the potential for Plant Scherer to install a membrane filtration technology under the proposed VIP, Georgia Power staff indicated that should such an installation occur, it would make use of a paste landfill where encapsulation of brine would occur.

[58] GenOn indicated that plans for Chalk Point and Morgantown included off-site disposal without FA from those plants because so much of that FA is already beneficially used.

[59] EPA also estimates that the volume of waste requiring disposal if membrane filtration was selected is 10 times the volume of waste estimated under the selected LRTR technology.

[60] 80 FR 21329 (April 17, 2015).

[61] 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.

environmental impacts.[62] As discussed below in connection with the VIP, however, EPA finds that, based on site-specific circumstances, the non-water quality environmental impacts identified on a nationwide basis could exist to a lesser extent (thereby not resulting in unacceptable non-water quality environmental impacts).[63]

While EPA views the foregoing reasoning as sufficient to find that membrane filtration is not BAT for existing sources, EPA notes that membrane filtration is projected to cost industry 26 percent more than estimated at proposal. As identified by commenters, the data used to establish limitations for membrane filtration for the proposed rule included pilots that preceded membrane filtration with chemical precipitation, while the cost estimates were based only on microfiltration as pretreatment. EPA agrees. Where EPA has information on pretreatment at foreign plants, none of those plants relies on microfiltration alone. To correct this inconsistency, in the final rule, EPA included the cost of chemical precipitation as the pretreatment method for the membrane filtration cost estimates and adjusted the set of data used to establish effluent limitations. For the final rule, both effluent limitations and cost estimates reflect data for systems using chemical precipitation as pretreatment before membrane filtration. EPA disagrees with comments that suggested the costs were not estimated correctly due to the use of incorrect flows and FA consumption rates. For a more detailed discussion of the membrane filtration public comments and responses, see DCN SE08615.

In addition to the estimated pretreatment costs, plants will also incur costs to dispose of the resulting brine. Some plants that may otherwise sell their FA may choose to use their FA to encapsulate the brine, thereby foregoing revenue from FA sales. Other plants that choose to continue to sell their FA will need to dispose of the brine using another disposal alternative, such as crystallization, at an additional cost. Costs are a separate statutory factor that 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 across the point source category as a whole,[64] these estimated increased costs do weigh against selecting membranes as BAT.

b. Other Technologies Evaluated for BAT Limitations

As described further below, EPA is also not establishing BAT limitations based on other technologies evaluated in the 2019 proposed rule and 2015 rule.

First, except for the permanent cessation of coal combustion and low-utilization subcategories discussed below, EPA is not establishing BAT limitations based on surface impoundments. One commenter suggested that EPA should adopt a high recycle rate system for FGD wastewater if the purge from such a system would receive BAT limitations equal to BPT limitations. The commenter relied on EPA's proposed BAT for BA transport water for this suggestion. Even for the purged wastewater from a high recycle rate BA transport water system, however, the final rule does not establish BAT limitations equal to BPT limitations. Instead, EPA leaves the BAT limitations to be determined by the permitting authority on a case-by-case basis, subject to BPJ. Such a case-by-case determination is not warranted for FGD wastewater because EPA has determined that CP+LRTR is available and economically achievable for treatment of FGD wastewater. Furthermore, EPA confirms its previous findings that surface impoundments are not as effective at controlling pollutants (such as dissolved metals and nutrients) as available and achievable technologies like CP+LRTR; however, as described in Section X below, other statutory factors and EPA's rulemaking record support the use of surface impoundments for two subcategories.

Second, except for the low utilization EGU subcategory discussed below, the final rule does not establish BAT limitations or PSES based on chemical precipitation alone. As EPA noted during the development of the 2015 rule, chemical precipitation is effective at removing mercury, arsenic, and certain other heavy metals. This technology alone does not remove nitrogen, nor does it remove the majority of selenium. Furthermore, the data in EPA's rulemaking record demonstrate that both LRTR and HRTR remove approximately 90 percent of the mercury remaining in the effluent from chemical precipitation treatment.[65] Because the combination of chemical precipitation with LRTR provides substantial further reductions in the discharge of pollutants industry-wide, EPA has established BAT based on CP+LRTR.

Third, the final rule does not establish BAT limitations based on thermal technologies, such as chemical precipitation (including softening) followed by a falling film evaporator, based on the statutory factors of total costs to industry and non-water quality environmental impacts. EPA received comments stating that thermal technologies are available, are unavailable, are economically achievable, and are not economically achievable. EPA agrees that these technologies are available but disagrees that these technologies are economically achievable. Although commenters arguing against availability raise a number of arguments, these arguments were considered and rejected in the 2015 rule, and no new information has been provided that warrants revisiting those findings. Since the 2015 rule, EPA has collected additional information on full-scale installations and pilots of thermal technologies to treat FGD wastewater. EPA's rulemaking record includes information about nine pilot studies conducted in the United States, providing performance data for five different thermal technologies. In addition, full-scale installations are operating at six domestic plants,[66] and a seventh purchased thermal equipment, but elected not to install it.[67] EPA is also now aware of seven foreign installations in Italy and China, five more foreign installations than at the time of the 2015 rule.

With respect to economic achievability, in the 2015 rule EPA rejected thermal technology as a basis for BAT limitations due to high costs to industry. New thermal technologies have been pilot tested and used at full scale since the 2015 rule, and related

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

[63] The same would be true for other VIP-compliant technologies (*e.g.,* thermal) that might be installed.

[64] *See, e.g., Texas Oil and Gas Ass'n et al.* v. *EPA,* 161 F.3d 923, 927 (5th Cir. 1998).

[65] Recall that the FGD mercury and arsenic limitations in the 2015 rule were based on chemical precipitation data alone because the plants operating biological systems were not using all of the chemical precipitation additives in the technology basis.

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

[67] This plant 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.

cost information demonstrates that thermal technologies are now less costly than when estimated for the 2015 rule. Nevertheless, the thermal costs evaluated in EPA's memorandum *FGD Thermal Evaporation Cost Methodology* (DCN SE08631) are still 2.4 times higher than the CP+LRTR technology selected as BAT, and 1.04 times higher than the membrane filtration costs in Option C. As authorized by section 304(b) of the CWA, which requires EPA to consider costs, as well as the discretion that the statute gives EPA to weigh the statutory factors, the Agency finds that, for this final rule, thermal technologies are not BAT due to the unreasonably high costs to industry.[68] Given the high costs associated with thermal 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, EPA is not establishing BAT limitations for FGD wastewater based on thermal technologies.

In addition to the unreasonably high costs, thermal technologies have unacceptable non-water quality environmental impacts associated with management of the resultant brine. Thermal technologies generate a brine similar to membrane filtration technologies. For this reason, portions of the discussion of membrane filtration brine above are based on brine management at plants with thermal systems. EPA also concludes that thermal technologies have unacceptable non-water quality environmental impacts. The reasoning is the same as for membrane filtration—unacceptable non-water quality environmental impacts would occur as a result of discouraging the beneficial use of FA, and additional disposal requirements would result from the production of a brine byproduct.

Furthermore, since the membrane filtration technologies evaluated in Option C appear to achieve similar pollutant removals at lower costs than thermal, as discussed later in this section, EPA is revising the basis for the VIP limitations adopted in the 2015 rule to membrane filtration, instead of thermal technologies.[69]

Finally, EPA is declining to establish BAT limitations for FGD wastewater as a case-by-case determination to be made by the permitting authority using BPJ. 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 the Agency's previous conclusion.

2. BA Transport Water

Under the final rule, EPA has selected high recycle rate systems as the technology basis for establishing the BAT requirements to control pollutants discharged in BA transport water. EPA determines that this technology is available and economically achievable after evaluating the factors specified in CWA section 304(b)(2)(B). In the 2015 rule, EPA selected dry BA handling or closed-loop wet ash handling systems as the technology basis for the no-discharge BAT requirements for BA transport water. EPA established no discharge effluent limitations based on these technologies, while also creating a limited allowance for pollutant discharges associated with leaks and certain maintenance activities.[70]

At the time of the 2015 rule, EPA estimated that more than 50 percent of plants 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, EPA now estimates that number to be over 75 percent of the industry. However, since the 2015 rule, EPA's understanding has changed regarding the types of available dry systems, and the ability of wet systems to operate a true closed-loop system (or to achieve complete recycle) has changed.

EPA is aware of advances in dry BA handling systems since the 2015 rule.[71] For example, in addition to under-EGU mechanical drag chain systems (described in the 2015 rule), pneumatic systems and compact submerged conveyors (CSCs, which are referred to in the proposed rule and in many public comments as submerged grinder conveyors, the appellation of the most commonly sold system) are now in use at some plants. EPA received comments that it failed to consider whether plants could retrofit their operation using CSC systems, and that EPA should retain the zero discharge limitations established in the 2015 rule. EPA also received comments that CSCs could be more costly than other technologies and that CSCs are not available. These included comments that CSCs are not demonstrated, that CSCs cannot handle the high ash loading rates of larger EGUs, and that retrofit with CSCs are not feasible for EGUs below grade or with space constraints leaving the EGU.

EPA disagrees with commenters who asserted that it failed to consider zero discharge requirements for BA transport water. While the Agency acknowledges that it did not identify technologies that could achieve zero discharge of BA transport water among its ''main'' regulatory options at proposal, the 2015 rule required zero discharge, and EPA described the technologies forming the basis for the 2015 rule and considered them and others, including CSCs, in this rulemaking.

With respect to costs, since the proposal, EPA has conducted conference calls with two plants, one of which operates a vacuum system and one that operates a CSC. The Agency acknowledges that, at proposal, it did not estimate costs of installing pneumatic systems (which include both dry vacuum or pressure systems) or CSCs. In the case of pneumatic systems, these systems tend to be more expensive than alternatives, and third party EPCs have indicated that the decision to install such systems is often driven by a combination of space constraints and limitations on water withdrawals. EPA continues to view pneumatic systems as more expensive than alternatives. With respect to CSCs, the Agency did not have cost data at proposal to conduct a cost analysis; however, since proposal the Agency has obtained CSC cost information from one plant, which demonstrates that for that plant it was the least-cost technology alternative. The costs for this plant are comparable to other technologies that EPA evaluated, and this finding is consistent with the representations of electric utilities, vendors, and third-party EPC firms, which have found that, on a plant-specific basis, CSCs may be the least costly bottom ash conversion option. However, because CSCs serve only an individual EGU, the more EGUs a plant has, the less economical this technology becomes. One vendor suggested that plants with three or more EGUs would generally find remote MDSs to be a least-cost alternative.

With respect to availability, commenters disputed that CSCs are demonstrated, but did not make the

[68] Some industry comments asserted that EPA underestimated the cost for thermal technologies and that more accurate costs would make these technologies economically unachievable. However, as described above, EPA need not adjust its cost assumptions because the Agency's own cost estimates result in unreasonably high costs.

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

[70] *See* 40 CFR 423.11(p).

[71] 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 EGU. Such systems include pneumatic and mechanical processes (some mechanical processes use water to cool the BA or create a water seal between the EGU and ash hoppers, but the water does not act as the transport medium).

same claim for pneumatic systems. Two full-scale CSCs became operational in 2019,[72] while 50 plants employing pneumatic systems are currently operating, with retrofits dating back to 1992. EPA is aware of only two CSCs in operation domestically today; however, the Agency has identified three additional CSCs currently being installed. Furthermore, in a conference call with one plant, it appears that, while there were some challenges, especially during installation, this particular system has operated successfully since its commissioning. However, this plant did not experience the same space constraints discussed below. Similarly, commenters raised issues with the ability of CSCs to handle high ash loading rates. While staff at one plant indicated that they successfully ramped up the speed of their CSC to handle more tons of ash per hour, and constructed a 100 percent redundant system, AEP submitted comments that the installation of CSCs at a larger lignite EGU with high ash loading rates would be considered high ''application risk.'' [73] Specifically, the lignite coal burned in this EGU has a much higher ash content, and its bottom ash tends to be more abrasive, relative to the typical bituminous coals burned and bottom ash produced at other AEP EGUs. As a result, 100 percent redundant systems would be required, which would eliminate the cost savings potential of the CSC system.[74] In contrast, no commenters claimed that pneumatic systems had loading rate constraints. Finally, industry engineers, third-party EPC firms, and vendors have indicated that pneumatic systems and CSCs can be installed at plants that are constrained from retrofitting the larger under-EGU MDS due to insufficient vertical space under the EGU. EPA has identified five EGUs at three plants where MDS installation is precluded due to insufficient vertical space. Commenters stated that CSCs, while smaller, could not be installed at these space-constrained plants where MDS installation is precluded without dismantling and excavating beneath the EGU, and EPA finds that, at a minimum, these five EGUs could face such limitations. AEP additionally described EGUs where space constraints would not preclude installation of a single CSC, but would preclude the installation of AEP's required 100 percent redundant design basis.[75] Commenters did not argue that space constraints would preclude pneumatic systems.

With respect to wet BA handling systems, in their petitions for reconsideration and in recent meetings with EPA, utilities and trade associations informed EPA that many existing remote wet systems are, in reality, ''partially closed'' rather than fully closed-loop, as assumed by EPA in the 2015 rule. Utilities and trade associations informed EPA that these systems operate partially closed, rather than closed, due to small discharges associated with: (1) Additional maintenance and repair activities not accounted for in the 2015 maintenance allowances; [76] (2) water imbalances within the system, such as those associated with stormwater; [77] and (3) water chemistry imbalances, including acidity and corrosiveness, scaling, and fines buildup. While some plants 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).

EPA agrees that the new information indicates that some plants with wet ash removal systems can operate as zero discharge systems, but in many cases must operate as high recycle rate systems. While some plants currently handle the challenges discussed above by discharging some portion of their BA transport water, the record demonstrates that plants can likely eliminate such discharges with additional process changes and expenditures. For the 2015 rule, EPA estimated costs of chemical additions to manage scaling. Now, companies could be adding additional treatment chemicals (caustic) to manage acidity or other chemicals to control alkalinity, using reverse osmosis filters to remove dissolved solids from a slipstream of the recycled water, adding polymer to enhance settling and removal of fine particulates (''fines''), and building storage tanks to hold water during infrequent maintenance or precipitation events. Industry-wide, EPA conservatively estimates the costs of the additional measures needed to achieve and maintain a truly closed-loop system to be $63 million per year in after-tax costs, beyond the costs of the systems themselves.[78] [79] These additional costs and process changes were not accounted for in the 2015 rule; however, as discussed in Section 5.3.3 of the Supplemental TDD, EPA has accounted for these costs in estimating the baseline costs of the BA limitations in the 2015 rule. Some commenters argued that EPA's costs were too conservative and asserted that these costs would not be necessary at most sites. While EPA agrees that it is not likely that all plants would incur these additional costs, EPA had no means to predict which plants would ultimately incur these additional costs, and thus the Agency reasonably assumed, for purposes of its economic achievability analysis, that each plant would incur these costs—in order to ensure that the costs upon which economic achievability are based are not underestimated. However, to the extent that necessary purges are smaller than this upper bound, EPA evaluated an alternate scenario in a Bottom Ash Alternate Purge Sensitivity Analysis (DCN SE09073). These lower costs were considered in addition to the costs presented above and would not change EPA's conclusion that high recycle rate systems, rather than closed-loop systems, are BAT. For further discussion of public comments and responses about closed loop and high recycle rate systems, *see* DCN SE08615.

EPA also recognizes the need for plants to consider their ability to comply with multiple environmental regulations simultaneously. As discussed in Section IV above, EPA has recently finalized the CCR Part A rule, requiring plants to cease receipt of waste in unlined surface impoundments by April 11, 2021 (with certain

[72] EPA only had a conference call with one of these two plants because the second plant did not respond to EPA outreach.

[73] AEP indicated that the vendor had found this application to be high risk as well.

[74] *See* DCNs SE08695 and SE08695A1.

[75] *See* DCNs SE08695 and SE08695A1.

[76] 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.

[77] 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 and runoff from a certain size precipitation event, these events may occur back-to-back, or plants may receive events with higher rates of accumulation beyond what the plant was designed to handle.

[78] Due to the final rule's changed compliance dates this estimate also includes discounting, which may overstate the savings.

[79] Utilities and EPC firms have discussed the availability of new dry systems, such as the CSC or pressure systems, which at some plants would have costs similar to recirculating wet systems (which would require a purge). Because EPA did not have cost information to determine the subset of plants for which new dry systems might be least costly, some portion of the costs estimated for this rule may be based on selecting recirculating wet systems at plants that could ultimately choose to install dry handling technologies. Thus, EPA may overestimate costs or underestimate pollutant removals at the subset of plants where such a dry system would be selected.

exceptions).[80] The challenges of operating a truly closed-loop system, discussed above, are compounded by the requirements of the CCR rule. Plants often send various CCR and non-CCR wastestreams, such as coal mill rejects, economizer ash, etc., with BA transport water into their surface impoundments. According to reports provided to EPA and conversations with electric utilities, several plants have already begun (or even completed) the transition away from impoundments and use the BA treatment system for some of their non-CCR (*i.e.,* non-FA, BA, or FGD) wastewaters.[81] This can be beneficial where it reduces the discharge of the non-CCR wastewaters, which might otherwise be discharged subject only to the TSS limitations applicable to low volume wastewater. At the same time, however, doing so can lead to or exacerbate scaling, corrosion, or plugging of equipment, all of which require process changes and additional expense to address, thereby complicating establishment of a closed-loop system. These problems could be avoided by purging the system from time to time, as necessary. Fewer than 25 percent of plants have not yet installed a BA transport water technology beyond surface impoundments and could potentially employ a dry system. However, due to the fast approaching cease-receipt-of-waste date under the CCR rule, it is probable that the majority of these plants have already begun their conversions to wet ash handling systems, which makes switching to a wholly different BA handling technology infeasible so late into the process.[82] For EPA to not allow a purge may encourage more of the non-CCR wastewaters mentioned above to be discharged as low volume waste. In order to accommodate both compliance with this rule and the CCR Part A rule, EPA finds it necessary for the permitting authority to allow for a high recycle rate system with some purge rather than a truly closed-loop system.

Furthermore, to the extent that plants had not designed, planned, procured, or commissioned segregated non-CCR wastewater treatment systems yet, requiring a plant to close the loop where closed loop operation would require wastewater segregation may force those plants to continue to send the non-CCR wastewater to their existing surface impoundments, thus extending their surface impoundment operations until new non-CCR wastewater systems can be commissioned. Some comments point to CCR rule requirements and Duke Energy's installation of lined retention basins in an attempt to demonstrate that non-CCR wastewaters can be managed separately within the 2015 rule time frames. EPA disagrees in both instances. While it might be possible for the retention basins being installed by Duke Energy to handle redirection of all of these non-CCR wastewaters, Duke Energy itself did not design for this, and instead designed and currently operates at least some of its high recycle rate systems to handle non-CCR wastewaters.[83] The CCR Part A rule generally requires plants to cease receiving waste in unlined surface impoundments no later than April 2021. Nevertheless, in cases where alternative capacity is not available, plants may request a site-specific alternative closure extension to operate that surface impoundment until 2023 or 2024. Thus, if the final rule were to require complete recycling of BA transport water, and this could only be accomplished by segregating wastewaters, at least some plants that might currently be able to meet the CCR Part A rule's April 2021 cease-receipt-of-waste date would instead be forced to request a site-specific alternative closure extension and continue operating the existing, unlined surface impoundment while they developed alternative disposal capacity to manage these newly segregated wastestreams.

In light of the foregoing process changes and associated engineering challenges facing plants needing to implement a true zero discharge BA transport water limitation in combination with the CCR rule, and to give plants flexibilities that will facilitate orderly compliance with the fast-approaching CCR rule deadlines, EPA determines that the basis of the BA transport water BAT limitations is the use of high recycle rate systems rather than dry handling or closed-loop systems, which were the technologies on which the zero discharge BAT limitation (adopted in the 2015 rule) were based. EPA's conclusion is based on its discretion to give particular weight to the CWA Section 304(b) statutory factor of ''process changes.'' Process changes to existing high recycle rate, non-closed loop systems made 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 plants could also prolong use of unlined surface impoundments.

EPA concludes that the factors discussed above are sufficient to support the Agency's decision not to select dry handling or closed-loop systems as BAT for BA transport water. 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. Some commenters stated that high recycle rate systems cannot be selected solely on the basis of higher costs when those costs are economically achievable. While EPA does not find the estimated additional cost to industry would result in plant closures, cost is a statutory factor that EPA must consider under section 304(b) of the CWA, and EPA has discretion in weighing the statutory factors, *see, e.g., BP Exploration & Oil Inc.* v. *EPA,* 66 F.3d 784, 799–800 (6th Cir. 1995) (citation omitted)). EPA views the higher cost of fully closed-loop systems as an additional factor supporting EPA's decision to reject closed-loop systems as BAT for treating BA transport water.

Some commenters argued that the proposed BAT based on high recycle rate systems is not warranted because that technology basis does not represent what is achieved by the single best performing plant, and even went so far as to say that this standard reflected the worst performing plant. EPA disagrees with these commenters. Some companies began proactive fleetwide conversions either before the effective dates of the 2015 rule or in some cases before the 2015 rule was signed. Many of these fleetwide conversions were to the remote MDS, a specific type of high recycle rate system that formed the ''closed-loop'' part of the 2015 rule BA transport water BAT technology basis. As discussed above, these systems do not all operate 100 percent closed-loop, as EPA assumed they did when finalizing the 2015 rule. Based on actual, measured purge rates in EPRI (2016), however, the Agency estimates that actual purge rates necessary on a day-to-day basis may be less than one percent of the system's volume, with higher purges necessary at less frequent intervals due to precipitation and maintenance. Furthermore, while surface impoundments can cover dozens of acres and contain volumes in the billions of gallons, typical high

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

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

[82] The CCR Part A rule acknowledges that a subset of plants which were lined or met the groundwater monitoring requirements and location restrictions may not yet have taken steps to convert their systems.

[83] For example, Duke Energy's Belews Creek plant manages its coal mill rejects wastestream in its recently commissioned remote mechanical drag system.

recycle rate systems have volumes closer to one-half million gallons (½ million). Thus, even assuming the proposed maximum allowable purge of 10 percent is necessary for a unit, the average gallons per day released by high recycle rate systems will be two percent of the average gallons per day released by surface impoundments, and therefore will also be 1.5 percent of the pollutant releases expected from surface impoundments. Industry-wide, EPA estimates this combination of reduced volume and increased recycling reduces discharges by 366 million pounds of pollutants per year, and thus makes reasonable further progress toward the CWA goal to eliminate the discharge of pollutants. *See* 33 U.S.C. 1251(a), 1311(b)(2)(A). Therefore, it is the combination of the reduced system volume and high capacity to recycle BA transport water that supports EPA's basis for high recycle rate systems as BAT.

The Agency also received comments that a generic 10 percent purge was not justified and that tighter limitations could be applied in some cases. One state commenter argued that it should be permissible for a permitting authority to continue to set zero discharge requirements. EPA has considered these comments and made modifications to improve the final rule. EPA is finalizing the site-specific alternative for which it solicited comment. Under the final rule, EPA establishes that the NPDES permitting authority will determine on a case-by-case basis the purge allowance (not to exceed 10 percent) necessary at a particular plant with a wet transport system.[84]

As with the proposal, this site-specific purge could in no case exceed 10 percent of the system volume per day on a 30-day rolling average. EPA concludes that the maximum purge volume would more than account for the challenges identified above, including infrequent large precipitation and maintenance events. EPA defines the term ''30-day rolling average'' to mean the series of averages using the measured values of the preceding 30 days for each average in the series. The purge volume is more appropriately determined on a case-by-case basis because these plants vary so much with regard to what purge is needed to maintain the wastewater treatment system versus the tradeoffs at each site regarding what options are available for the non-CCR wastewater, Thus, 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).[85]

Some commenters suggested that EPA establish a BMP plan rather than a 10 percent purge. Commenters seemed to misunderstand the 10 percent purge in relation to BAT. When EPA establishes BAT, it selects a technology that is available nationally and economically achievable industry-wide. EPA then calculates the effluent limitations expected from the performance of the selected technology. Only after establishing those limitations might EPA impose an additional BMP plan under section 304(e) of the CWA. Here, BAT is high recycle rate systems, and based on the available data, EPA has established limitations that such systems can achieve.

Under the final rule's site-specific requirement for determining discharge allowances there may be wastewater from whatever is purged by the high recycle rate system, and plants may wish to discharge this wastewater. At proposal, EPA solicited comment on whether specific technologies should be selected as BAT for the purged wastewater. Some commenters suggested that surface impoundments should be selected because the high recycle rate systems already make reasonable forward progress. While EPA agrees that high recycle rate systems make reasonable forward progress in accordance with the CWA, the Agency must still consider any available treatment alternatives for the purged wastewater. Two considerations make determining a nationwide BAT for these discharges challenging and site-specific. First, in the case of precipitation or maintenance-related purges, such purges could be large volumes at infrequent intervals.[86] Each plant necessarily has different climates and maintenance needs that make selecting a uniform treatment system more difficult. Second, utilities have stated that discharges of wastewater associated with high recycle rate systems are sent to low volume wastewater treatment systems, which are typically dewatering basins or 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 plants. For further purge-related public comments and responses see DCN SE08615.

In light of the information discussed above, and 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), EPA concluded that BAT limitations for any wastewater that is purged from a high recycle rate system and then discharged, should be established by the NPDES permitting authority on a case-by-case basis using BPJ. EPA concludes that permitting authorities are in a better position than EPA to examine site-specific climate and maintenance factors, especially since the permitting authority will already be determining the allowable volume of purge, up to a maximum of 10 percent of the system's volume. Permitting authorities will also be in a better position than EPA to account for site-specific treatment technologies and their configurations already installed or being installed to comp0ly 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.

EPA is not identifying surface impoundments as BAT for BA transport 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 plants 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 (D.C. Cir. 2018). Since very few CCR surface impoundments are composite-lined, the practical effect of this ruling is that many plants with operating impoundments likely will cease sluicing waste to these impoundments in the near future. In the 2015 CCR rule, EPA estimated that it would be less costly for plants to install under-EGU or remote

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[84] While this could include a purge of zero percent, EPA believes that such a determination could only occur in those cases where the system is designed to function, and is demonstrated to successfully perform, as a zero discharge system.

[85] 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 plant, and therefore overestimates pollutant discharges associated with the BAT for BA transport water.

[86] For example, rainfall exceeding a 10 year, 24-hour event would only be expected to occur twice during the 20-year lifetime of the equipment.

drag chain systems and send BA to landfills rather than continue to wet sluice BA and replace unlined impoundments with composite lined impoundments. This supports the suggestion that surface impoundments are not BAT for all plants; however, EPA is identifying surface impoundments as BAT for two subcategories, as discussed later in this section. In addition, EPA is defining a new wastestream, BA purge water, which is a more accurate term than the proposed ''maintenance purge water.'' BA purge water consists of the water permissibly purged from a high recycle rate system. This wastestream is no longer defined as BA transport water; therefore EPA is making conforming changes to the BPT regulations to make clear that the BPT limitations based on surface impoundments for TSS and oil and grease, which are applicable to BA transport water, also continue to be applicable to BA purge water. Effluent limitations for BA purge water are to be established by the permitting authority based on BPJ.

3. Voluntary Incentives Program (VIP)

The final rule includes a VIP that provides the certainty of more time (until December 31, 2028, instead of a date determined by the permitting authority that is as soon as possible beginning October 13, 2021) for plants to implement new BAT limitations if they adopt additional process changes and controls that achieve limitations on mercury, arsenic, selenium, nitrate-nitrite, bromide, and TDS in FGD wastewater, based on membrane plus pretreatment technology. The 2015 rule included a similar VIP that was based on thermal evaporation technology and that would extend the compliance deadline for VIP participants by five years. 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. As in the 2015 rule, EPA expects the additional time to achieve compliance, combined with other factors (such as the possibility that a plant's NPDES permit may need more stringent limitations to meet applicable water quality standards), may lead some plants to choose this option for future implementation by incorporating the VIP limitations into their permit when applying.

Some commenters argued that EPA lacks authority under the CWA to establish a VIP with compliance deadlines beyond three years from the date of promulgation of the final rule. EPA disagrees. The VIP program established in the 2015 rule was not challenged in court (and also not challenged by these particular commenters who challenged other aspects of the 2015 rule). The statute is silent with respect to BAT effluent limitations established after 1989. As the U.S. Court of Appeals for the Fifth Circuit recently held, the CWA's requirement in 33 U.S.C. 1311(b)(2)(C), (D), and (F) that effluent limitations be met no later than three years after promulgation plainly applies only to initial BAT limitations, not revisions of such effluent limitations. *Clean Water Action* v. *Pruitt,* 936 F.3d 308, 316 (5th Cir. 2018). The compliance deadlines in Sections 301(b)(2)(C), (D), and (F) of the CWA only apply to effluent limitation guidelines that were established prior to the outside dates specified in those provisions. They do not apply to effluent limitations guidelines established in 2020. For further discussion, see DCN SE08615.

New information in several utilities' internal analyses and contractor reports provided to EPA since the 2015 rule, as well as information EPA gathered in meetings with utilities, EPC firms, and vendors, indicates that plant decisions to install the more expensive thermal systems both prior to and following the 2015 rule were driven by water-quality-based effluent limitations imposed by the NPDES permitting authority. These documents and meetings also revealed that several plants considered installing membrane filtration technologies under the 2015 rule VIP as well, and EPA is aware of one company, GenOn, that has plants that opted into the 2015 VIP with plans to use membrane filtration technologies to meet the VIP limitations. Despite membrane filters not being available nationwide and not being appropriate for all facilities, due to electric utilities' continued interest in this technology, EPA evaluated membrane filtration as an alternative basis for the VIP limitations.

Under the final rule, EPA establishes VIP limitations based on membrane filtration, replacing the 2015 rule VIP limitations based on thermal technology, because EPA estimates that membrane filtration systems are less costly than thermal systems and have comparable pollutant removal performance. Membrane filtration achieves pollutant removals comparable to thermal systems in situations where the thermal system would discharge, which the VIP in the 2015 authorized. Due to the significantly higher costs of thermal systems compared to chemical precipitation followed by LRTR, EPA does not expect that many plants would install a new thermal system under a VIP program as the least cost technology, though some might install it to comply with water quality-based effluent limitations established by their permitting authority.[87] As authorized by section 304(b) of the CWA, which allows EPA to consider costs, EPA is selecting membrane filtration as the technology basis for the VIP limitations, with limitations for mercury, arsenic, selenium, nitrate-nitrite, bromide, and TDS.[88]

Also, as authorized by section 304(b) of the CWA, which allows EPA to consider process changes and non-water quality environmental impacts, EPA is revising the compliance date for the VIP limitations to December 31, 2028. That is the date EPA has determined that the membrane filtration technology will likely be available for full-scale implementation at those plants that choose to adopt it. EPA proposed to conclude that membrane technology would be nationally available in 2028. Some commenters asserted that it is inappropriate for EPA to predict a date in the future when a technology will become nationally available for CWA purposes. EPA agrees with these commenters and in the final rule concludes only that membrane technology will likely be available by 2028 on a site-specific basis. Although EPA will continue investigating the availability and economic achievability of this technology, EPA cannot predict with certainty that the technology will be nationally available in 2028.

The 2028 time frame is based on the time necessary to pilot, design, procure, and install both the membrane filtration systems and the brine management systems, including disposal capacity. Additional time is also often necessary to complete the permitting process. This time frame should also be adequate for alternative VIP-compliant technologies, such as thermal systems. Because EPA establishes BAT effluent limitations based on a specific technology's performance, but does not require a specific technology for compliance, thermal systems would still be allowable under the final rule VIP program, as would alternative non-membrane technologies that meet the limitations.

Some commenters argued that the 2028 deadline for the VIP is too long, citing shorter construction time frames and an email from one electric utility

[87] See, *e.g., https://www.powermag.com/how-low-temperature-evaporation-treats-fgd-wastewater/ (DCN SE09091).*

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

suggesting a VIP deadline of 2026 would be feasible.[89] While EPA agrees that some plants opting into the VIP may be able to install the technology sooner, part of the incentive for the program, which is expected to result in substantial additional pollutant removals from plants opting in, is the extra time provided to achieve compliance. Finally, EPA notes that this time frame is also similar to the eight-year period between promulgation of the 2015 rule and the 2023 deadline for the 2015 rule's VIP. For a further discussion of VIP timing in public comments and responses, see DCN SE08615.

EPA finds that using membrane filtration as the technology basis for the VIP does not result in the same non-water quality environmental impacts that informed the Agency's decision not to select membranes as BAT for the entire industry. First, participation in the VIP is voluntary and EPA would expect it to be selected only by plants for which it presents the least cost option, accounting for particular FA production, use, disposal and market availability. Where plants have limited FA markets and already dispose of their ash, they could dispose of the brine using encapsulation or ash conditioning without reducing beneficial use of FA. EPA understands that this is the case at Duke's Mayo Plant. Other plants may have sufficient external sources of FA and landfill space to dispose of an encapsulated material. EPA understands that this is the case at GenOn's two remaining Maryland plants. Of course, brine disposal options are not the only considerations for plants deciding whether to participate in the VIP. As noted above, GenOn indicated that final plans for treatment technology for both units will depend on the standards of this final rule, and for one of its units, changing electricity demand.

Finally, forthcoming changes in membrane filtration brine disposal options may reduce the non-water quality environmental impacts associated with encapsulation, as discussed in Section VII(b)(i) above. Through discussions with several utilities and EPRI, EPA learned that a developing ''paste'' technology may allow plants 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 current 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, reduce the volumes and pollutant concentrations in leachate.[90] [91] EPA is aware that part of Plant Scherer's current, long-term pilot study is intended to evaluate this very process.

Two additional challenges were identified for the membrane filtration technology or the paste technology described above. The first challenge regarding the paste alternative is developing approaches to manage wastes (*e.g.,* flush water) from periodic cleaning of the paste transportation piping, where such piping is used.[92] Consistent with the proposal, and as authorized by section 304(b) of the CWA, which allows EPA to consider the process employed, EPA is finalizing a modification of the definition of FGD wastewater and ash transport water to explicitly exclude water used to clean FGD paste piping. This enables plants using paste piping for brine encapsulation and disposal in an on-site landfill to clean residual paste from pipes and other equipment more easily.

The second challenge is that some plants that might want to re-use the first stage, membrane-treated FGD wastewater without a polishing RO stage as EGU makeup water could be discouraged from doing so. As discussed in Section VII(B)(1) above, RO is the standard treatment for source water (*e.g.,* groundwater and surface water) used in the EGU to generate steam. These existing systems must ensure sufficiently low levels of pollutants (such as TDS) to prevent corrosion, fouling, foaming, scale deposits, and loss of heat transfer efficiency within the EGU. This extremely clean water is turned into steam at the EGU and is used to turn the blades of the turbine to generate electricity before being condensed back into water at the cooling towers and returned to the EGU. Some plants that participate in the VIP and install a membrane filtration system to treat their FGD wastewater by the 2028 compliance date might find it advantageous to direct their partially treated FGD wastewater through their EGU makeup water RO system, instead of employing a second stage RO treatment to meet the membrane filtration-based limitations in this rule. In these cases, it is unlikely that the FGD wastewater treated using the first stage of the membrane filtration treatment system alone would meet the final membrane-based limitations (*i.e.,* an internal limitation could not be met), and after mixing with other source water (*e.g.,* river water or groundwater) at the EGU makeup water RO treatment system, it could be infeasible to demonstrate compliance based on existing methods.[93] Small amounts of EGU water are handled as EGU blowdown, which is sent to flash tanks where most will turn to steam. While some of the rest can be recycled, at times it is necessary to discharge this water, subject to existing limitations for low volume waste (as the existing regulatory definition of low volume wastes includes EGU blowdown). This could occur where the EGU is emptied for maintenance (*e.g.,* to repair tube leaks) or shut down (*e.g.,* during outages). Reduced water withdrawals are a non-water quality environmental impact that not only saves plants money to withdraw and treat significant volumes of water, but would also reduce impingement and entrainment. EPA projects that the final rule VIP will result in 292,000 gallons per day of reduced water withdrawals at eight plants. While some of these reduced water withdrawals may be due to increased recycling within the FGD system, at least a portion of these reduced withdrawals would be expected where a plant used the permeate as EGU makeup water. Therefore, to encourage this practice where EGU makeup water is ultimately discharged as EGU blowdown, the EPA is making a change from proposal by clarifying that membrane permeate and thermal

[89] This company appears to be retiring its coal-fired EGUs from service, and therefore EPA does not project that it would use the VIP whether the deadline is 2026 or 2028.

[90] 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/ (DCN SE09092).*

[91] Although 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.

[92] 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.

[93] As discussed in Section XIII of this preamble, the data points used for developing limitations of three constituents in the VIP included too many non-detect values to develop a monthly limit, and these data points did not include dilution water, as would be the case here.

distillate used as EGU makeup water is not considered FGD wastewater, and is thus removing them from the definition of FGD wastewater at 423.11(n).

A compliance date of December 31, 2028 for the VIP allows time for further development of this paste technology, increasing its availability to plants, and giving plants more time to acquire any necessary permits for landfill cells for brine encapsulated with FA and lime if needed; allowing plants time to conduct pilot testing, demonstrations, and further analyses to identify and implement process changes associated with membrane filtration; and assessing the long-term performance of the technology for treatment of FGD wastewaster.

Taken together, EPA's final VIP gives plants greater flexibility when choosing a technology to achieve the established VIP pollutant limitations, resulting in pollutant reductions beyond the BAT limitations that are generally applicable to the industry. Under the proposal, EPA estimated that 18 plants may opt into the VIP program. Based on public comments and cost estimate revisions, under the final rule, EPA now estimates that eight plants (13 percent of plants estimated to incur FGD compliance costs) may opt into the VIP program.

EPA is not finalizing the VIP for PSES for several reasons. First, the CWA dictates that plants subject to PSES comply within three years after the limitations are promulgated. Thus, the statute does not allow for additional time to implement VIP limitations. Second, there are only two plants with indirect discharges of FGD wastewater. One of these plants has announced its retirement, and EPA expects that plant to participate in the subcategory for EGUs permanently ceasing the combustion of coal. The other plant has a water quality-based effluent limitation that would already call for the use of a technology that could meet the VIP limitations. Since a PSES VIP would not grant any additional time or flexibility, EPA determines that such a provision is not justified.

C. Additional Subcategories

In the 2015 rule, EPA established subcategories for small EGUs (less than or equal to 50 MW nameplate capacity) and oil-fired units. EPA subcategorized small EGUs due to disproportionate costs when compared to the rest of the industry and subcategorized oil-fired units both because they generated substantially fewer pollutants and are generally older [94] (and more susceptible to early retirement). In the 2015 rule, 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." [95]

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

EPA did not propose, and is not changing in this final rule, the 2015 rule subcategorization of small EGUs and oil-fired units. The final rule does, however, incorporate and expand on EPA's previous analysis of characteristics and differences within the industry. EPA has authority in a national rulemaking to establish different limits for different plants after considering the statutory factors listed in section 304(b). *See Texas Oil & Gas Ass'n* v. *EPA,* 161 F.3d 923, 938 (5th Cir. 1998) ("We find nothing in the text of the CWA indicating that Congress intended to prohibit the promulgation of different effluent limits within a single subcategory of point sources . . . . The fact that EPA must promulgate rules for classes of polluters rather than individual polluters does not mean that EPA is required to treat all polluters within each class identically. The phrases 'for categories and classes' and 'within such categories or classes' simply do not, by their terms, exclude a rule allowing less than perfect uniformity within a category or subcategory.). The final rule includes subcategories applicable to FGD wastewater and BA transport water for EGUs with low utilization and EGUs permanently ceasing the combustion of coal. In addition, the final rule includes a subcategory applicable to FGD wastewater for power plants with high FGD flows. These subcategories are discussed below.

1. Plants With High FGD Flows

Consistent with the proposal, EPA is finalizing a subcategory for plants with high FGD flows based on the statutory factor of cost. Specifically, this subcategory faces a disproportionately higher capital cost than other plants in the industry. The 2015 rule discussed the ability of high flow plants 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 plant.[96] This variance request relied primarily on two facts. First, TVA stated that Cumberland's FGD wastewater flow volumes are several million gallons per day,[97] approximately an order of magnitude higher than many other plants with comparable generation capacity, and millions of gallons per day higher than the next highest flow rate in the entire industry.[98] 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 plant 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.[99] Second, as a result of the inability to recycle these high FGD flows, TVA stated that the cost of a biological treatment system would be high.

The final rule subcategorizes plants with FGD purge flows of greater than four million gallons per day, after accounting for that plant's ability to recycle the wastewater to the maximum limitations for the FGD system materials of construction, to avoid placing a disproportionate cost on such plants. 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 at that high flow plant would result in a capital cost of $171 million,

[94] Age is a statutory factor for BAT. CWA section 304(b), 33 U.S.C. 1304(b).

[95] 80 FR 67856 (November 3, 2015).

[96] 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.

[97] 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.

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

[99] 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.

and an O&M cost of approximately $20 million per year.[100] EPA's cost estimates are higher than TVA's, a $235 million dollar capital cost plus $21 million per year in O&M. EPA proposed to find that these costs are disproportionate, and thus proposed to subcategorize the Cumberland plant and any other plant with similarly high flows.

Some commenters argued that EPA cannot legally create a subcategory of one plant. These commenters suggest that EPA must issue a fundamentally different factors (FDF) variance rather than create a subcategory. Other commenters argued that EPA cannot create a subcategory based on costs alone and that EPA had overestimated costs. Finally, commenters claimed that EPA reversed previous findings about the ability to recycle within the Cumberland FGD system without sufficient explanation.

With respect to subcategory size, EPA does not agree that the CWA prohibits the creation of the subcategory for plants with high flows, and EPA discussed its CWA authority earlier in this section. Here, EPA has determined that plants that have particularly high FGD flows are different from other plants in the industry with respect to the compliance costs they would incur if they were expected to achieve the otherwise applicable limits based on CP+LRTR. While EPA is currently aware of only one plant that operates with flows at this high level, any plant in the industry that operates with these flow levels would qualify for the different limitations established in this subcategory.

With respect to FDF variances, EPA does not agree that CWA section 301(n) somehow restricts EPA's authority to establish subcategories. Rather, section 301(n) provides an ''acceptable alternative to subcategorizing an industry to account for plant-specific characteristics.'' *Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d 177, 221 (5th Cir. 1989) (citation omitted). While EPA is ''not required to establish separate subcategories for single plants,'' *Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d at 239, it is not prohibited from doing so. Furthermore, FDFs are different from subcategories in important ways because they typically are based on information that EPA did not have a chance to consider in the national rulemaking. *See* 40 CFR 125.31(a)(2) (a request for establishment of effluent limitations based on fundamentally different factors shall be approved only if the factors are ''fundamentally different from those considered by EPA in establishing the national limitations'').

With respect to establishing a subcategory based on costs, EPA is required to consider ''cost'' under the statute, and that includes consideration of costs for a subcategory. *See Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d 177, 239 (5th Cir. 1989). EPA has broad discretion in deciding how to account for the consideration factors and the weight to be accorded to each factor. *See Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1045 (D.C. Cir. 1978); *Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d at 214; *Texas Oil & Gas Ass'n* v. *EPA,* 161 F.3d 923, 928 (5th Cir. 1998). Here, EPA has determined that total capital costs are a reasonable way to consider cost in this scenario because they demonstrate the significant up-front disparity created just to install the system. EPA acknowledges that the capital cost estimates developed by the Agency at proposal were, and continue to be for the final rule, higher than TVA's estimates, but notes that the O&M costs are nearly identical. EPA's estimated capital costs for Cumberland amount to one quarter of the total capital costs to the entire industry for treating FGD wastewater with CP+LRTR, but they would still amount to approximately one fifth if TVA's estimated capital costs were used. Both instances represent disproportionately high costs, as compared to the rest of the industry. Furthermore, while the baseline IPM run discussed below used costs of the 2015 rule (*i.e.,* CP+HRTR), which are somewhat higher than those for this final rule, these costs were projected to result in reduction of Cumberland's operations by 96 percent and partial retirement of the plant in order to meet the 2015 rule requirements.

With respect to recycling within the FGD scrubber system, EPA has not reversed any previous findings. At proposal, EPA found that, based on the maximum chlorides concentrations allowable in ''once through'' FGD systems, many of these systems could still employ some recycling of FGD water within the scrubber. For plants like Cumberland, this was true in 2015 and is true today. The amount of recycling EPA estimated for Cumberland, however, is small relative to its flows. This recycling is explicitly accounted for in the 2019 proposal, and now in the final rule analysis of O&M costs. For further public comments and responses on the propriety of this subcategory, see DCN SE08615.

As authorized by section 304(b) of the CWA, which allows EPA to consider costs, EPA is finalizing a new subcategory for FGD wastewater based on these unacceptable disparate costs. EPA finds that chemical precipitation does not impose the same unacceptable disparate costs. Therefore, the subcategory BAT is based on chemical precipitation, with effluent limitations for mercury and arsenic.

2. Low Utilization EGUs

EPA is establishing a new subcategory for EGUs with low utilization (*i.e.,* peaking EGUs) based on the statutory factors of cost, non-water quality environmental impacts (including energy requirements), and other factors the Administrator deems appropriate (*i.e.,* harmonization with Clean Air Act and CWA regulations which apply to electric utilities). Low natural gas prices and other factors have led to a decline in capacity utilization for the majority of coal-fired EGUs. According to EIA 923 data,[101] overall coal-fired production for 2017–2018 was approximately one-third lower than in 2009, with the majority of EGUs decreasing utilization, some of them significantly. While the majority of EGUs were base load in 2009, coal-fired EGUs today often operate as cycling or peaking EGUs, responding to changes in load demand.[102]

In light of these industry changes, EPA examined the costs of the 2019 proposed BAT limitations and pretreatment standards for FGD wastewater and BA transport water on the basis of MWh produced, rather than the nameplate capacity (which was used to subcategorize EGUs with 50 MW capacity or less in the 2015 rule). Specifically, the Agency proposed a subcategorization for plants producing less than 876,000 MWh per year on a rolling two-year basis. EPA received many comments on this subcategory, including some that suggested different MWh utilization thresholds or tiering with different limitations for different thresholds. Some commenters argued that the proposed cutoff was not based on utilization at all, and that it could apply to very high utilization EGUs that just happened to have a smaller nameplate capacity, or recommended that EPA consider other utilization measures such as the eight percent CUR threshold used in the 2012 Mercury and Air Toxics Standards rule (77 FR 9304, February 16, 2012). EPA agrees with the latter comments and has made changes

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

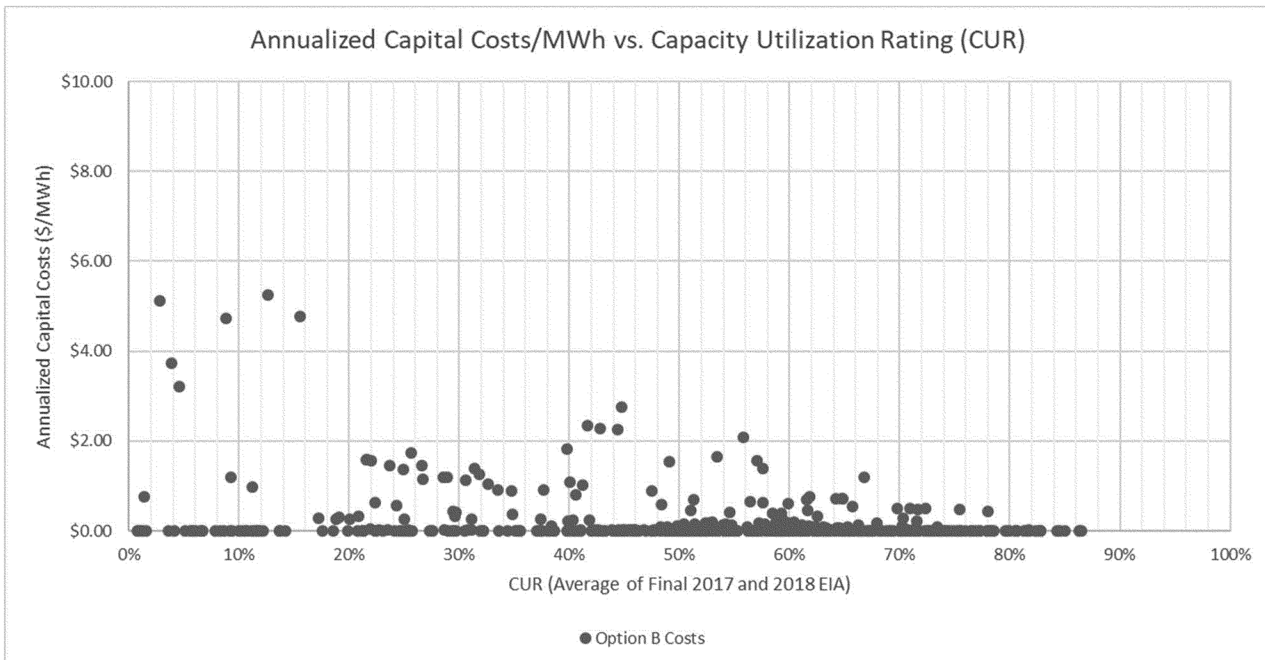
[101] *https://www.eia.gov/electricity/data/eia923/*

[102] In meetings and conference calls with electric utilities and trade organizations, several examples were provided of former base load plants that have since modified operations to be load-following, or that no longer produce at all except for peak days in summer or winter. These discussions tracked closely with changes in production reported in the EIA 923 data.

in the final rule to ensure that this subcategory is focused on low utilization EGUs and better reflect the intent of this subcategory, which its name makes apparent. Specifically, EPA has changed how it determines low utilization from a method which was based on MWh/yr (a production metric) to one based on utilization as measured by CUR.

Similar to EPA's finding regarding small units 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 EGUs with low capacity utilization. Specifically, EPA focused its analysis on annualized capital costs as opposed to O&M costs because O&M costs are often tied to CUR, a measure of how frequently and to what extent an EGU is generating electricity: The more an EGU runs, the higher the CUR, and the more residuals it generates and must pay to dispose of.[103] In contrast to O&M costs which correlate to how much an EGU is operating, capital costs do not vary with generation as they correspond to the original design of a system that can handle the maximum FGD scrubber purge flow and ash generation rate such that the system can handle a high-end/peaking power demand scenario (typically the EGU's nameplate capacity which would result in a CUR of 100%) and still meet the limitations. Thus, as utilization decreases, O&M costs are expected to decrease proportionally, while capital costs are not.

Of the EGUs which EPA estimates have production lower than the proposed rule's 876,000 MWh/yr threshold, nearly two-thirds have a CUR over 25 percent. This confirms that the subcategory as proposed was more indicative of low production rather than low utilization. Thus, to properly evaluate low utilization, EPA compared costs on a CUR basis. Figure VIII–1 below presents annualized capital costs per MWh produced versus CUR. These are the costs of Option B (*i.e.,* no subcategorization) as measured against the status quo, rather than against the 2015 rule baseline. This figure shows that four to six EGUs with a CUR between 0 percent and 16 percent have disparately higher capital costs per MWh produced than facilities with a higher CUR.



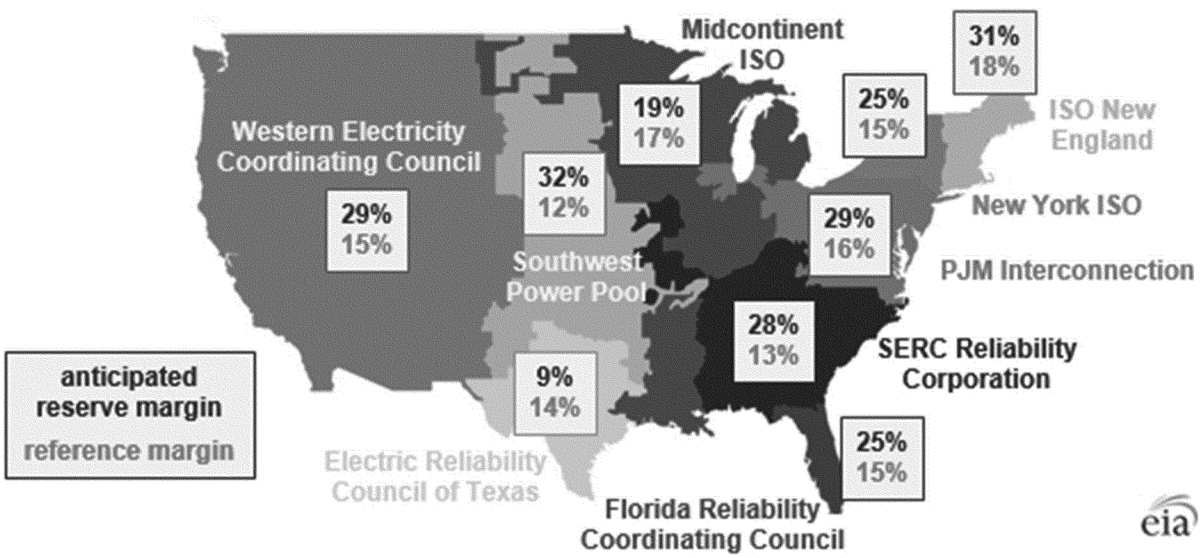
Some commenters argued that the CWA does not allow subcategorization based on costs. Some commenters also argued that costs should properly be compared on a plant basis, and that costs are not disparate on a plant basis. EPA disagrees with these comments. See the discussion in the introduction of this subcategorization section. EPA also notes that it subcategorized units with a 50 MW nameplate capacity or less based on disparate costs alone in the 2015 rule, and that provision of the 2015 rule was not challenged. With respect to commenters' arguments that the relevant metric is plant costs rather than unit costs, EPA finds that many decisions to retire, repower, or upgrade treatment are made at the EGU level, and many other EPA regulations are tied to EGUs, as discussed below. Thus, an EGU-level comparison is appropriate when examining disparate costs of this rule.

In addition to disparate costs, EPA considered non-water quality environmental impacts (including energy requirements). Because CUR is a reflection of the frequency and extent of an EGU's generation, LUEGUs necessarily operate much less frequently, delivering electricity only during peak loading. For example, EGUs operating for approximately one month out of the year would have a CUR just over eight percent, but their continued operation is useful, if not necessary, for ensuring electricity reliability in the near term. Some commenters disagreed that electricity reliability is a concern, and they pointed to excess reserve margins in some regions of the country. EPA acknowledges that electricity reliability may not be a concern everywhere in the U.S., nor will it be a concern in all seasons. For instance, the most recent NERC winter reliability assessment states, ''Anticipated

[103] Unlike residuals, wastewater volumes need not always vary directly with utilization due to flexibility in how the system is operated and timing of the generation of wastewater.

resources in all assessment areas meet or exceed their respective Reference Margin Levels for the upcoming winter period.'' [104] In contrast, Figure VIII–2 below presents the most recent (summer 2019) anticipated reserve margins as well as the reference margin designed to ensure electric reliability. As seen in that figure, the most recent summer assessment showed one region (ERCOT) that was not anticipated to meet its reference margin, and another (MISO) which was anticipated to be very close to its reference margin (19 percent vs.17 percent).

Summer 2019 reference margins and anticipated reserve margins in select NERC regions



The figure above also does not present NERC sub-regions or local distribution, which may present additional reliability challenges. For example, one trade association commenter provided an example in Southeast Michigan where a natural gas distribution system caught fire during the winter of 2019. The temporary shortage caused by the fire and cold temperatures caused local auto and semiconductor manufacturers to shut down or cut production and put Michigan residents at risk of service interruptions.[105] To the extent that LUEGUs are able to remain in service, they would be available to help alleviate these types of short-term localized shortages and outages.

Finally, EPA considered an ''other factor[ ]'' the Administrator deems appropriate,[106] which is the harmonization of regulations. DOE/EIA does not define what a peaking unit is, nor do the CAA or CWA. Nevertheless, EPA has grappled with this issue in previous regulations under these two statutes. A discussion of these regulatory examples is provided in *Steam Electric Effluent Guidelines Reconsideration—Evaluation of Final Rule Subcategories* (DCN SE09071). These regulations have in some cases specified a 10 percent CUR, an eight percent CUR, or have allowed for consideration of CUR in site-specific decisions. This provides some flexibility in implementing these rules, including reduced monitoring, different recordkeeping, and alternative compliance technologies for units meeting the relevant CUR threshold. As is clear in these examples, EPA has long considered certain low CUR EGUs as important to local reliability and resiliency of the power grid. Various definitions of low CUR have been used by EPA programs to identify where regulatory requirements should be different. While in all of these example regulations EPA concluded that additional flexibility was warranted for EGUs based on CUR, EPA did not define peaking EGUs, nor is the Agency defining peaking EGUs in this final ELG.

EPA has consistently given more flexibility to EGUs operating at the margins of the electric grid. While EPA has not consistently implemented the same CUR for all of its regulations, in practice the difference between eight percent and 10 percent CUR is minor, approximately one week of operations. Furthermore, while the subcategory is not limited to EGUs that already operate at these levels, EPA estimates that only one EGU that will incur costs under this final rule falls between eight and 10 percent CUR, based on EIA data from 2017–2018. In light of the range of CURs over which there appear to be disparate costs, the potential to contribute to reserve margins or provide local flexibility in case of unexpected capacity disruption, and the desire to harmonize with the range of CURs that have been provided additional flexibilities in other EPA rules, the final rule establishes a subcategory for LUEGUs with an average annual CUR of less than 10 percent per year averaged over 24 months. For further public comments and responses on the propriety of this subcategory, see DCN SE08615.

Consistent with the proposal, for this low utilization subcategory, EPA selected chemical precipitation as the technology basis for BAT limitations and PSES for FGD wastewater, with effluent limitations for mercury and arsenic. Also, for this subcategory EPA selected composite lined surface impoundments as the BAT technology basis for BA transport water and established limitations for TSS based on surface impoundments in combination with a BMP plan under section 304(e) of the CWA. For example, surface impoundments that meet the

[104] NERC (North America Electric Reliability Corporation). 2019. *2019–2020 Winter Reliability Assessment.* November. Available online at: *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf* (DCN SE09093).

[105] U.S. News. 2019. Bitter Cold and Natural Gas Shortages Shutter Auto Plants. DCN SE08655A081.

[106] 33 U.S.C. 1314(b)(1)(B).

engineering and design requirements in 40 CFR 257.71 would comply with this requirement. While EPA projects that some plants in this subcategory with unlined surface impoundments are likely to meet these TSS limitations using technologies other than surface impoundments once they have closed any unlined surface impoundments under the CCR rule, EPA projects that two plants will continue to operate lined surface impoundments.[107]

As authorized by section 304(b) of the CWA, which allows EPA to consider costs, non-water quality environmental impacts (including energy requirements), and other factors the Administrator deems appropriate, EPA explicitly finds that additional technologies are not BAT for this subcategory. Some commenters argued that the technologies identified for this subcategory do not represent the single best plant within the subcategory. To an extent, commenters were correct in identifying more advanced technologies (*e.g.,* biological treatment) in use within the LUEGU subcategory as it was proposed. However, those technologies were typically installed when the EGU had been operated at a much higher utilization rate. Thus, it is not appropriate to draw conclusions about what BAT for LUEGUs is today based on what might have been available and economically achievable when these EGUs operated at greater capacity utilization rates (and would therefore not have qualified as LUEGUs). In addition, the LUEGU subcategory in the final rule is narrower than the subcategory EPA proposed, with fewer plants eligible and fewer plants with advanced technologies in place.

Other commenters took a different view, suggesting that, for LUEGUs, BAT should be set equal to BPT. EPA disagrees with these commenters and declines to set BAT equal to BPT. In this final rule, EPA finds that chemical precipitation for treatment of FGD wastewater, by itself, does not impose on LUEGUs the same disproportionate costs as CP + LRTR and that chemical precipitation is technologically available and economically achievable. Similarly, the requirement of a BMP plan to recycle what water can be recycled in a BA transport water system does not impose on LUEGUs the same disproportionate costs as installation of a high recycle rate system and is technologically available and economically achievable. Plants that can achieve some level of recycle, but not 90 percent, are required to do just that. While this may still be significant due to changes occurring under the CCR rule, the fact that significant reductions might occur at little cost does not make the BMP requirement so burdensome as to warrant defaulting to BPT.

In light of the foregoing discussion, EPA finds that 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 from BA transport water, are the only technologies that would not impose disproportionate costs or cause unacceptable non-water quality environmental impacts for this subcategory. 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, EPA rejects setting BAT limitations for BA transport water in this subcategory on a case-by-case basis using BPJ because 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 and unacceptable non-water quality environmental impacts, according to EPA's analysis above. For further public comments and responses on the appropriate BAT for this subcategory, see DCN SE08615.

3. EGUs Permanently Ceasing Coal Combustion by 2028

Under the final rule, EPA establishes a subcategory for EGUs permanently ceasing the combustion of coal by 2028, based on the statutory factors of cost, the age of the equipment and plants involved, non-water quality environmental impacts (including energy requirements), and other factors as the Administrator deems appropriate (harmonization with the CCR rule alternative closure provisions).

Some commenters argued that EPA does not have authority to establish a subcategory for EGUs that are projected to retire because the CWA does not give it authority to establish a subcategory to ''avoid premature closures'' of plants. EPA disagrees that it lacks authority to establish the subcategory for EGUs that will cease combustion of coal by 2028. While it may be true, as commenters suggested, that Congress contemplated that marginal plants may close under a BAT standard, it required that EPA consider specific factors in devising a nationally applicable ELG rule: ''Factors relating to the assessment of best available technology shall take into account the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate.'' 33 U.S.C. 1314(b)(2)(B)). And, as stated previously in this preamble, EPA has considerable discretion in deciding how to account for the statutory factors and the weight to be accorded to each factor. *See Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1045 (D.C. Cir. 1978); *Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d at 214; *Texas Oil & Gas Ass'n* v. *EPA,* 161 F.3d 923, 928 (5th Cir. 1998). Based on the consideration of the statutory factors presented below, EPA is within its statutory authority to establish different limitations for such plants to help avoid unacceptable impacts.[108]

EPA proposed to include only retiring EGUs in this subcategory but solicited comment on the inclusion of repowering EGUs. Electric utility commenters across the board suggested that EPA include all EGUs that would cease the combustion of coal, and thus the generation of the wastewaters regulated under this final rule. EPA agrees with these comments. EGUs that are repowering cease generation of BA transport water and FGD wastewater, just as retiring EGUs do. Furthermore, inclusion of repowering EGUs will enhance harmonization of the rules

[107] Furthermore, EPA notes that plants may choose to retrofit a surface impoundment or construct a new lined surface impoundment under the CCR rule.

[108] It is of no moment that, in 2015, EPA declined to establish different limits for plants that might soon retire. EPA is free to change its mind as a matter of policy, so long as it explains its decision. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 42 (1983). That one EPA Administrator may weigh the statutory consideration factors differently from a previous one does not make the decision arbitrary, particularly where courts have long held that the Administrator has considerable discretion in weighing the factors. *See also Nat'l Ass'n of Home Builders* v. *EPA,* 682 F.3d 1032, 1038 & 1043 (D.C. Cir. 2012) (a revised rulemaking based ''on a reevaluation of which policy would be better in light of the facts'' is ''well within an agency's discretion,'' and '' '[a] change in administration brought about by the people casting their votes is a perfectly reasonable basis for an executive agency's reappraisal' '' of its policy choices) (citations omitted).

applicable to this industry and give greater clarity to the regulated community. As discussed in the CCR Part A final rule, the alternative closure provisions for surface impoundments where there is ''permanent cessation of the coal fired boiler'' in Section 257.103(f)(2) includes surface impoundments at EGUs that convert to natural gas or other fuels. The final subcategory in this ELG final rule adopts nearly identical terminology as the language in Section 257.103(f)(2) of CCR Part A. EPA believes the phrase used in § 423.11(w) of this rule ''permanent cessation of coal combustion'' will avoid confusion over the intent to include repowering EGUs, and is intended to parallel the EGUs that would be able to satisfy Section 257.103 of the CCR rule. Thus, adopting the same approach for these ELGs will create consistency and certainty for the regulated community. Furthermore, not treating repowering as equivalent to closure could create an unfavorable incentive for a plant that desires to continue operating to, instead of repowering, retire and construct a new EGU on a greenfield, rather than use existing infrastructure. It would be better environmentally for the plant to use existing transmission and distribution infrastructure where possible to limit potential new impacts from greenfield project development. Therefore, as described below, this subcategory includes repowering EGUs.

EPA has continued to gather information about plant and EGU retirements, deactivations, and fuel conversions since the 2015 rule from company announcements, industry public comments, and government databases as discussed in *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule memorandum* (DCN SE08688). In the 2019 proposed rule, EPA identified 107 plants which had announced, commenced or completed such actions since the development of the 2015 rule record, the most frequently stated reason in these public statements or filings being market forces, such as the continued low price of natural gas (49 plants).[109] This was followed by other reasons (46),[110] [111] environmental regulations (33),[112] and consent decrees (10). The fact that environmental regulations were listed in these public statements or filings by nearly one-third of these plants and that ELGs were specifically listed by some respondents suggests that additional flexibility may help to avoid premature closures of some plants and/or EGUs. As presented in Figure VIII–2 and section VII.C.2 of the preamble above, the most recent summer assessment showed one region (ERCOT) that was not anticipated to meet its reference margin, and another (MISO) which was anticipated to be very close to its reference margin (19 percent vs.17 percent). Thus, EPA concludes that premature closure of some plants and/or EGUs is an unacceptable non-water quality environmental impact because it could impact reliability. Therefore the avoidance of these premature closures weighs in favor of subcategorization.

Some commenters took issue with EPA's analysis of a hypothetical plant (see 84 FR 64640, November 22, 2019) and suggested that EPA should have evaluated the costs and pollutant loadings of EGUs that fall into this subcategory. EPA agrees with the latter suggestion, and the final rule thus includes in the baseline all EGUs retiring and repowering after 2023 (the latest compliance deadlines in the 2015 rule). For those EGUs that would be subcategorized as permanently ceasing coal combustion by 2028, EPA evaluated the changes in costs and pollutant loads under regulatory Option A.

As noted above, EPA gathered readily available information from publicly available sources, company announcements, industry public comments, and government databases to identify EGUs. A list of EGUs EPA believes to be retiring or repowering between 2024 and 2028 is presented in *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule memorandum* (DCN SE08688). Twenty-three EGUs at 12 plants may incur costs under the final rule absent a subcategory for units ceasing coal combustion by 2028.[113] Under Option B, these EGUs combined have estimated capital costs of $209 million and estimated O&M costs of $21 million per year, leading to combined annualized costs as high as $63 million per year.[114] When compared to the costs per MWh for EGUs not ceasing coal combustion by 2028, the shorter amortization periods for these LUEGUs lead to much higher costs per MWh in some cases. For example, while Winyah Unit 2 and Will County Unit 4 have approximate costs of $6/MWh under a normal 20-year amortization period, over the shortened amortization period these costs jump to over $10/MWh. These costs would both be among the highest, if not the highest, costs absent a subcategory for units ceasing coal combustion by 2028.

EPA received comments that the compliance deadline for this subcategory should be different. Commenters suggesting a longer time frame proposed site-specific extensions past 2028, or later dates for LUEGUs. Some commenters also suggested that this time frame was too long for a variety of reasons. With respect to comments that the time frame should be shortened, EPA received comments presenting the time frame for building replacement capacity. One example provided by Southern Company demonstrated a real-world case where the construction of the natural gas replacement EGUs took eight years from the initial coal EGU retirement decision.[115] Furthermore, as presented above, EPA has demonstrated that costs are disparate over these shorter time frames. Even if commenters disagree with EPA's characterization of these time frames as short, compressing cost recovery into these smaller amortization periods does result in disproportionate costs. Responding to comments that the time frame should be lengthened, EPA further examined the 24 EGUs that have announced retirement or fuel conversion after 2028 presented in *Steam Electric Effluent Guidelines Reconsideration—Evaluation of Final Rule Subcategories* (DCN SE09071). Of these 24 EGUs, only four EGUs at two plants are projected to incur costs under a final ELG rule. These EGUs will continue burning coal until 2033 and 2035, meaning that they will be able to

[109] This is consistent with recent analyses of the costs of coal-fired electric power 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;* (DCN SE09094). (2) *https://insideclimatenews.org/news/25032019/coal-energy-costs-analysis-wind-solar-power-cheaper-ohio-valley-southeast-colorado* (DCN SE09095).

[110] Announcements for some power plants cited several rationales, hence the numbers do not add to 107.

[111] ''Other'' includes age, reliability of the plant, emission reduction goals, decreased local electricity demand, plant site limitations, and company goals to invest in clean/renewable energy.

[112] Approximately 31 percent of the facilities identified specific environmental regulations affecting their decision-making. Specific environmental regulations, when mentioned, included CPP, MATS, ELGs, CCR Rule, and Regional Haze Rules.

[113] Three EGUs at two plants are expected to retire or cease burning coal between permit renewal and the no later than compliance date.

[114] This upper bound assumes costs are all incurred between 2021 and the announced year of closure or conversion to a different fuel source.

[115] While replacement capacity may not be necessary in all cases, the Agency believes that it should not tie the hands of electric utilities by foreclosing the possibility.

amortize their costs over a time frame closer to the estimated 20-year amortization period used for the industry as a whole. Unlike the EGUs ceasing coal combustion by 2028, the costs per MWh of these four EGUs do not increase significantly when evaluated with a shortened amortization period, and appear to fall in the range of the rest of the industry. Thus, changes to the latest year for permanent cessation of coal combustion is not justified based on disparate costs.[116] Finally, with respect to both sets of comments suggesting longer and shorter time frames, changing the time frames would eliminate harmonization with the CCR rule. The CCR Part A rule finalized alternative closure provisions under 257.103(f) for coal-fired EGUs that permanently cease by 2028. For EPA to have requirements with that date under the CCR rule and a different date (earlier or later) for requirements under the ELGs would introduce unnecessary confusion and potentially limit the flexibilities deliberately afforded to the regulated community under one or both regulations. In meetings with EPA, utilities expressed two other concerns related to retiring or repowering units which would support this subcategory and the associated time frames. First, several utilities discussed the possibility that public utility commissions (PUC) would not allow cost recovery for equipment purchased near the end of a plant's useful life, resulting in stranded assets. Although the utilities indicated that PUCs have historically allowed for cost recovery even after the retirement of an EGU, they provided recent examples of PUCs rejecting cost recovery, which makes the prospect of continued recovery after retirement less certain. Second, 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.[117]

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 plants were to bring their projected retirement dates forward.[118] That report found that if retirements happen faster than the system can respond (by constructing new base load, *e.g.*), significant reliability problems could occur. NERC cautions that, though this stress test is not a predictive forecast,[119] the findings are consistent with the concern that electric utilities conveyed to EPA, viz., that the well-planned construction of new generation capacity and orderly retirement of older plants are vital to ensuring electricity reliability. While EPA received comments that the scenarios that EPA evaluated at proposal did not result in the same level of retirements as the NERC stress test, any retirements caused by EPA, including under this regulation, could contribute to such a scenario. Furthermore, as presented in the discussion of LUEGUs above, inadequate reserve margins in some regions and commenter-provided examples of electricity upsets support EPA's view that marginal plants should not be forced into retirement while they still have a useful role to play in ensuring electric reliability.

In light of the information discussed above, and EPA's authority under section 304(b) to consider cost, the age of equipment and plants involved, non-water quality environmental impacts (including energy requirements), and other factors that the Administrator deems appropriate, EPA is establishing a new subcategory for EGUs that plan to permanently cease combustion of coal no later than December 31, 2028, subject to a certification requirement (described in Section XIV). For this subcategory, EPA is establishing BAT limitations for TSS for both FGD wastewater and BA transport water based on surface impoundments as the selected technology basis.[120] Some commenters disputed EPA's selected technology basis for EGUs in this subcategory. Comments argued that EPA cannot legally select surface impoundments for this subcategory, failed to base BAT on the best performing plant in the subcategory, and failed to consider that units in this subcategory could lease rather than purchase equipment to help meet the final limitations. 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. For further public comments and responses on this subcategory, see DCN SE08615.

Next EPA examined the treatment technologies employed at plants that have units that qualify for this subcategory. Four of the 12 plants retiring or repowering between 2024 and 2028 are projected to incur FGD wastewater costs. Of these, two have chemical precipitation, one has chemical precipitation plus biological treatment, and the remaining plant has physical settling via surface impoundments. The one plant with biological treatment is Duke Energy's Allen Steam Station, which installed an HRTR system more than 10 years ago. Thus, unlike other plants with no current treatment, this plant has had sufficient time to amortize its costs. The fact that a plant could absorb the costs of an advanced wastewater treatment technology a decade ago when it operated at a much higher utilization does not demonstrate that, moving forward, plants already planning to retire could absorb such costs. For BA transport water, nine of the 12 plants will incur BA transport water costs under this final rule. Four of these plants already operate high recycle rate systems, while the remaining five plants only have wet sluice of their ash to surface impoundments. Again, the fact that a plant could easily absorb the costs of such systems previously, does not indicate that such systems are BAT moving forward.

Finally, although EPA agrees with commenters that a wide variety of

[116] While it is possible additional plants might choose to retire or repower soon after 2028 and have not yet announced their intent to do so, it is not possible to predict such possibilities.

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

[118] 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.* (DCN SE09096)

[119] ''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.''

[120] EPA is not specifying that the BAT technology basis is composite lined impoundments here, as it did for the low utilization subcategory, because under the CCR rule, plants must cease receiving waste in their unlined surface impoundments by April 11, 2020, but plants that need additional time to develop alternate capacity to manage their wastestreams may continue to use their unlined surface impoundments under the alternative closure provisions of 40 CFR257.103(f)(1) or (2). Units falling within the alternative closure provision of (f)(2) must both complete closure of their unlined surface impoundments and permanently cease combustion of coal by 2023 or 2028 (depending on size of the impoundment). Thus, use of unlined surface impoundments under the ELG up to that date would be compatible with the CCR rule, and nothing in this final ELG would authorize the use of an unlined surface impoundment outside of these CCR Part A rule flexibilities.

wastewater treatment systems are available to lease, availability alone does not eliminate the issues already identified. Commenters provided information that systems were available for lease but did not provide information that leasing a treatment system would be less costly than the alternative. In contrast, during one of the conference calls identified above, EPA learned that one utility had conducted an evaluation of leasing equipment for one of its plants. At that plant, the leasing option was not less costly than purchasing and installing the same equipment. Data in the record regarding costs of leasing FGD wastewater treatment systems is limited. EPA had meetings or conference calls with several vendors and plants regarding leasing treatment equipment, but only obtained specific cost data for a single plant. EPA used the information provided about this plant to evaluate leasing in Cost to Lease Flue Gas Desulfurization Wastewater Treatment memorandum (DCN SE08633). For further public comments and responses on the issue of costs associated with leasing FGD wastewater treatment systems, see DCN SE08615.

After considering the information above, EPA finds that additional technologies such as chemical precipitation, CP+LRTR, CP+HRTR, membrane filtration, or thermal technologies for FGD wastewater, and the dry handling/closed-loop technologies or 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 EGUs 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 finds that surface impoundments are the only technology that would not impose such disproportionate costs on this subcategory of EGUs. Establishing surface impoundments as BAT for this subcategory alleviates the choice for these plants 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 final rule. This subcategory also allows electric utilities to continue the organized phasing out of EGUs that are no longer economical, in favor of more efficient, newly constructed generating stations, and helps prevent the scenario described in the NERC stress test. Additionally, it ensures that plants 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.[121] EPA notes that, in order to complete closure by 2028, plants may have to cease receiving waste well in advance of that date; however, a 2028 date ensures that the final rule does not restrict the use of this alternative closure provision regardless of when a plant ultimately ceases receipt of waste. Furthermore, EPA rejects setting BAT limitations for either FGD wastewater or BA transport water in this subcategory on a case-by-case basis, using BPJ because the technologies an NPDES permitting authority would necessarily consider are the same systems that result in unacceptable disproportionate costs and unacceptable non-water quality environmental impacts according to EPA's analysis (described above). Because these EGUs are already nearing the end of their useful lives as coal-fired units, and are susceptible to early retirement or fuel conversion, losing the use of surface impoundments for wastewater before currently planned closure dates would undermine the flexibility of the CCR alternative closure provisions. This could hasten the retirement of units in a manner more closely resembling the reliability stress test discussed above, which is an unacceptable non-water quality environmental impact (including energy requirements) of compromised electric reliability. For further public comments and responses on the issue of the appropriate BAT technology for this subcategory, see DCN SE08615.

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 BAT 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.[122] The 2015 rule also specifies the factors that the permitting authority must consider in determining the ''as soon as possible'' date.[123] 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. Like the 2015 rule, as part of the consideration of the technological availability and economic achievability of the BAT limitations in this proposal, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at plants to meet the final rule's limitations and standards. Where such limitations and standards justified a different ''no later than'' date, EPA has changed this date, as detailed below. However, where EPA continued to project that technologies would be available by the existing ''no later than'' deadlines, those deadlines have been considered appropriate and retained.

In the 2015 rule, and as amended by the 2017 postponement rule, EPA selected the time frames described above to enable many plants to raise needed capital, plan and design systems, procure equipment, and then construct and test systems. The time frames also allow for consideration of plant changes being made in response to other Agency rules affecting the steam electric power generating industry (*e.g.,* the CCR rule). EPA understands that some plants may have already installed, or are now installing, technologies that could comply with the final limitations. While these plants could therefore potentially meet the standards of the final rule by the earliest date on which the limitations may become applicable, EPA received comments asking that EPA not select November 1, 2020 for the ''as soon as possible'' date, and further pointed out that this November 1, 2020 date was chosen to allow for sufficient time to conduct this rulemaking rather than with respect to when plants could meet the final limitations in this rule. As the Agency explained in the 2017 postponement rule, the November 1, 2020 date was selected based on the time frame for finalizing a new rule (*i.e.,* this final rule).

For this final rule, EPA concluded that the earliest date the industry can achieve compliance with these new,

[121] 40 CFR 257.103(b).

[122] 40 CFR 423.11(t).

[123] 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 plant in response to greenhouse gas regulations for new or existing fossil fuel-fired power plants 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)

more stringent limitations is October 13, 2021. EPA notes that, while the limitations being finalized today are in some cases more flexible than those of the 2015 rule, in other cases they are more stringent. For instance, mercury limitations for FGD wastewater in the final rule are several times more stringent than those in the 2015 rule. Even a plant that might have a fully installed and operational biological treatment system to meet the 2015 rule might have to modify its physical/chemical pretreatment system or install post-treatment to ensure meeting these lower mercury limitations. Thus, even plants with treatment systems may need additional time to evaluate those systems against the new limitations, make modifications, and optimize performance. These changes might be minor in some cases; in other cases they could require procurement and installation of additional equipment. For example, Duke Energy has recently procured ultrafilters for its HRTR systems.

At the same time as these plants may have to procure and install additional equipment, the global pandemic related to COVID–19 has disrupted normal supply chains and forced companies to rethink how construction is conducted, in many cases putting in place additional protocols such as distancing. In conversations since the proposal with staff at Platte River Power Authority, Duke Energy, Georgia Power, and GenOn, each company indicated that it had made changes to construction projects or experienced delays. For example, GenOn had on-site contractors mobilized at some plants in February, but due to restrictions imposed in March, those contractors left the sites and GenOn was forced to seek out an alternate vendor. This led to a six-month delay on that project.[124] Several companies also indicated that they have had to postpone outages. Since these outages are necessary to perform final hookups to newly installed wastewater treatment systems, delays will directly impact the time frames over which plants could meet any limitations. Furthermore, any additional time short of one year from the publication date of this rule would be insufficient for plants in many areas of the country because the construction season would already be over. Instead, EPA finds that setting the earliest applicability dates for both bottom ash transport water and FGD wastewater as October 13, 2021, which also happens to be toward the end of the 2021 construction season, would allow companies time to analyze the final rule, make plans, and construct any necessary treatment system upgrades under COVID–19 construction protocols. In addition to the considerations above, allowing a full year after publication will allow plants time to adjust to changed electricity demand due to the pandemic and the subsequent phases of reopening;[125] build in evaluations with the most recent utilization rates; and evaluate whether participation in either the LUEGU or permanent cessation of coal combustion subcategories would be appropriate for any EGUs.

With respect to the latest compliance dates, EPA collected updated information regarding the technical availability of the proposed FGD and BA BAT technology bases and the VIP alternative. Based on the engineering dependency charts, bids, and other analytical documents in the current record, individual plants may need two to three years from the effective date of any rule to install and begin operating a treatment system to achieve the BAT limitations for FGD wastewater. Information in EPA's rulemaking 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).[126] For BA transport water, the record at proposal indicated a typical time frame of 15 to 23 months to raise capital, plan and design systems, procure equipment, and construct a dry handling or closed loop or high recycle rate BA system. Nothing in the comments received by EPA leads the Agency to a different conclusion.

EPA received comments that the record did not support longer compliance time frames for FGD wastewater, based on the typical installation time frames. EPA disagrees with these comments. While the time frames above may be appropriate for an individual plant, several utilities and EPC firms pointed out difficulties in retrofitting biological treatment systems on a company-wide or industry-wide basis. Moreover, the same engineers, vendors, and construction companies are often used across plants. These same issues do not arise for chemical precipitation systems, which are substantially more prevalent in the industry, and in many cases would likely be installed to meet the cease-receipt-of-waste deadlines in the CCR Part A rule. That CCR rule finalized April 11, 2021 as the cease-receipt-of-waste date, with a site-specific alternative closure extension provision in 257.103(f) that allows a plant to get extensions up to as late as 2023 or 2024, depending on whether the plant was already required to close prior to the *USWAG* mandate. To stop receiving waste in an unlined surface impoundment, a plant 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 final 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, EPA is extending the ''no later than'' date for meeting FGD wastewater BAT limitations based on CP+LRTR to December 31, 2025. Thus, for FGD wastewater, BAT limitations based on CP+LRTR do not apply until a date determined by the permitting authority that is as soon as possible beginning October 13, 2021, but no later than December 31, 2025.

With respect to BA transport water, commenters expressed several concerns, including: A concern that 2023 was not a sufficient time to plan for and meet new limitations, nor a sufficient time to conduct a BPJ analysis for the BA purge water and install any appropriate technology; a concern that these dates should be harmonized with the final CCR Part A rule, and that these dates were not harmonized with the time frames proposed for FGD wastewater (including the FGD makeup water exemption).[127] EPA agrees with some comments, disagrees with others, and concludes that extension of the 2023 date as proposed is warranted, for the reasons discussed below.

[124] DCN SE08621.

[125] Peer reviewed research from Imperial College in March 2020 suggested that some form of mitigation measures (*e.g.,* social distancing) might be required for 18 months or longer which would correspond to September 2021. Available online at: *www.imperial.ac.uk/media/imperial-college/medicine/sph/ide/gida-fellowships/Imperial-College-COVID19-NPI-modelling-16-03–2020.pdf.* (DCN SE09097)

[126] Many plants have already completed initial steps of this process, having evaluated water balances and conducted pilot testing to prepare for implementing the 2015 rule.

[127] Commenters also stated that these time frames would be insufficient for installation of dry CSC systems. While dry handling is no longer considered part of the technology basis, EPA acknowledges that dry handling would be an alternative means for meeting the final limits, and agrees that based on information provided in the Rawhide conference call as well as the CCR rule docket, CSC systems may require a longer time frame for installation.

EPA disagrees that specific facts asserted by commenters warrant extending the time beyond 2023. First, EPA concludes that many plants could meet the 2023 date as proposed. As described at proposal, the industry continues to shift away from the use of surface impoundments for handling BA due to the CCR rule which has requirements to cease receipt of waste by a date certain. The CCR Part A final rule establishes a cease receipt of waste date of April 11, 2021 for many of these impoundments; however, other provisions of the 2015 CCR rule have cease receipt of waste dates which have already passed. With respect to the concerns related to BPJ analysis timing and FGD wastewater exemption, EPA responds that these timing issues can be addressed with flexibilities for the respective provisions, rather than extending the ''no later than'' dates. For BPJ, plants can work with their permitting authority to develop reasonable compliance time frames to meet whatever BPJ is selected for BA purge water. EPA has clarified in the regulatory text that BA transport water sent to the FGD system for use as FGD makeup water becomes FGD wastewater. Thus, whatever limitations apply to FGD wastewater at the time, also apply to the BA transport water used in the FGD systems as FGD makeup water. Where the compliance date for FGD wastewater limitations occurs after the compliance date for BA transport water limitations, plants would continue to meet the BPT limitations for the BA transport water used in the FGD system as FGD makeup water until the former compliance date.

However, EPA agrees that other facts presented by commenters and in EPA's rulemaking record do warrant extending the latest compliance dates for BA transport water beyond 2023. First, the CCR Part A rule alternate closure provision in 257.103(f)(1) now allows a subset of surface impoundments to receive waste as late as 2024. Harmonizing compliance time frames to at least 2024 would allow plants to make use of the CCR Part A rule's additional flexibility. Second, EPA acknowledges that deadlines were harmonized across wastestreams in the 2015 rule, providing plants an opportunity to plan for any upgrades in a more integrated fashion. Harmonization of FGD wastewater and BA transport water ''no later than'' dates would be consistent with that approach.

Considering all the factors described above, EPA is extending the ''no later than'' date for compliance with the generally applicable BA transport water BAT limitations to December 31, 2025. While harmonization with other wastestreams' compliance dates could support either a 2023 or 2025 ''no later than'' date for the BA transport water limitations in this rule, the 2023 date would frustrate the flexibilities provided for impoundments until 2024 to close under the final CCR Part A rule and lead to disjointed plant planning across the two wastestreams. The more holistic approach is to select the 2025 date, thereby harmonizing the dates applicable to the two wastestreams being finalized in this rule. Thus, for BA transport water, BAT limitations based on high recycle rate systems do not apply until a date determined by the NPDES permitting authority that is as soon as possible beginning October 13, 2021, but no later than December 31, 2025.

Importantly, for both FGD and BA, EPA distinguishes the ''no later than'' date from the ''as soon as possible'' date, determined by the permitting authority in accordance with the factors in 40 CFR 423.11(t). While EPA is postponing the ''no later than'' dates in this final rule, where plants can comply with these final limitations sooner, NPDES permitting authorities are already required to incorporate those earlier permit dates, as specified in 423.11(t). Thus, this change to the ''no later than'' dates to December 31, 2025 will not change the dates included in every NPDES permit.

In addition, as discussed earlier, EPA is giving plants that opt into the VIP until December 31, 2028, to meet the VIP FGD wastewater limitations, which are based on membrane filtration technology. That is the date on which EPA finds that the membrane filtration technologies may be available, on a site-specific basis, to plants that might choose to participate in the VIP and be bound by those limitations. The final rule gives plants sufficient time to work out operational issues related to being the first plants in the U.S. to treat FGD wastewater using membrane filtration at full scale, as well as to conduct engineering studies on the encapsulation mix appropriate at that site for the disposal of the resulting brine. As previously explained, both of these issues contributed to EPA's decision that membrane filtration is not appropriate as a nationwide BAT. EPA also believes that a compliance deadline of December 2028 is an effective incentive for plants to opt into a program that can achieve significant pollutant reductions.

E. Additional Rationale for the Final PSES

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 LRTR biological treatment are comparable to those achieved with HRTR biological systems. On this basis, EPA concludes that mercury, arsenic, selenium, and nitrate/nitrite pass-through POTWs, as it concluded in the 2015 rule.

With respect to BA transport water, EPA projects that plants converting to dry handling or recycling all of their BA transport water would continue to perform as the zero discharge systems EPA used in its 2015 rule pass-through analysis. As explained in Section VII.b.ii, for those plants using high recycle rate systems, the final rule allows the NPDES permitting authority to establish, on a case-by-case basis, the volume of discharge (with a maximum of 10 percent of the system volume per day, on a 30-day rolling average) and to determine the BAT limitations for that discharge based on BPJ. For indirect dischargers, control authorities can establish local limitations on a BPJ basis.

Thus, like BAT, the final rule establishes PSES based on Option A: PSES for FGD wastewater based on CP+LRTR, and PSES for BA transport water based on high recycle rate systems. EPA is establishing these technologies as the bases for PSES for the same reasons that the final rule selects these technologies as the bases for BAT. Moreover, the final rule establishes the same subcategories for PSES as it does for BAT limitations, for the same reasons described earlier.[128]

As with the final BAT effluent limitations, in considering the availability and achievability of the final PSES, 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 CWA section 301(b), which does not specify a compliance date for BAT limitations promulgated after 1989, CWA section 307(b)(1) requires that pretreatment standards shall specify a time for compliance not to exceed three years from the date of promulgation. Therefore, the PSES compliance dates established by this rule are three years

[128] Where the final rule establishes any subcategory that identifies BAT based on surface impoundments, with a restriction on TSS, there is no such parallel restriction for the analogous PSES subcategory because POTWs effectively treat TSS.

from promulgation of this rule. Unlike limitations on direct discharges, limitations on indirect discharges are not implemented through an NPDES permit and are directly enforceable. EPA has determined that all existing indirect dischargers can meet the standards within three years of the effective date of this final rule.

F. Summary of Economic Achievability

As 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 the RIA). At the time of the 2015 rule, the IPM model showed a total incremental closure of 843 MW of coal-fired electric power generation as a result of the ELGs, corresponding to a net effect of two EGU closures.[129] However, since then, natural gas prices have remained low, additional coal plants have retired or refueled, and changes that have been proposed to several environmental regulations have been included in those model runs. Owing to these changes, EPA ran an updated version of IPM (see Section VIII.C.2 for additional discussion of these updates).

EPA also ran IPM to analyze the effect of the final rule. As of run year 2030, IPM estimates a total net increase of 1.3 GW in coal-fired electric generating capacity compared to the baseline IPM run (compliance with the 2015 rule), reflecting full compliance by all plants with the final rule. This change represents a net increase in capacity; however, due to increased capacity utilization of several plants in one region, IPM results show a net increase of one additional early closure. These IPM results indicate that the final rule is economically achievable for the steam electric power generating industry as a whole, as required by CWA section 301(b)(2)(A).

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

G. Summary of Non-Water Quality Environmental Impacts

For the 2015 rule, 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. Some commenters stated that consideration of air pollution changes suggest a more stringent option is warranted. EPA reevaluated these impacts in light of the changed industry profile, as well as the requirements of the final rule. Based on the results of these analyses EPA determines that the final rule has acceptable non-water quality impacts, including those air pollution impacts raised by commenters. *See* additional information in Section 7 of the Supplemental TDD, as well as Section X of this preamble.

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

As EPA did for the 2015 rule, the Agency examined the effects of the final rule 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 plants, the average per houshold cost savings under the final rule is $0.49 per year, as compared to the 2015 rule.

EPA similarly evaluated the effect of the final rule on minority and low-income populations. As explained in Section XII, 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, 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 power plants and are expected to accrue the benefits or drawbacks of the final rule to a greater degree than the general population.

VIII. Costs, Economic Achievability, and Other Economic Impacts

EPA evaluated the costs and associated impacts of the final rule on EGUs at steam electric power plants. These costs were analyzed within the context of compounding regulations and industry trends that have affected steam electric power plants' profitability and power generation. These include the effects of current environmental regulations (*e.g.,* final ACE rule, and final CCR Part A rule), as well as other market conditions, described in Section V.B. This section provides an overview of the methodology 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 details, including results for other regulatory options EPA considered.

Neither the cost estimates, nor the pollutant loading estimates (see section IX of the preamble), prepared by EPA for the purpose of evaluating various regulatory options, are designed to reflect changes to an industry with exact precision. *See BP Exploration & Oil, Inc.* v. *EPA,* 66 F.3d 784, 800 (6th Cir. 1995) ('' 'The CWA does not require a precise calculation of BAT and NSPS costs.' '') (quoting *NRDC, Inc.* v. *EPA,* 863 F.2d 1420, 1426 (9th Cir. 1988)); *Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d 177, 237–38 (5th Cir. 1989) (''The Act requires the EPA to 'take into account' the costs of BAT; it does not require a precise calculation. The EPA 'need make only a reasonable cost estimate in setting BAT'; it is sufficient if the EPA develops 'a rough idea of the costs the industry would incur.' '') (internal quotations and citations omitted); *see also Texas Oil & Gas Ass'n* v. *EPA,* 161 F.3d 923, 936 (5th Cir. 1998) (EPA's effluent reduction estimates were performed ''only to satisfy the CWA's unrelated requirement that the EPA 'identify' in its regulations the degree of effluent reduction attainable through the application of BAT . . . As such, even serious flaws in the effluent reduction estimates could not provide grounds for remanding the zero discharge limit.'') (citing 33 U.S.C. 1314(b)(2)(A)).

In developing ELGs, and as required by CWA section 301(b)(2)(A), EPA evaluates economic achievability to assess the impacts of applying the limitations and standards on the industry as a whole, which typically includes an assessment of incremental plant closures attributable to a regulatory option. As described in more detail below, the final rule is expected to provide cost savings when compared to the baseline. Like the prior analysis of the 2015 rule and the analysis of the 2019 proposal, the cost and economic impact analysis for the final rule focuses on understanding the magnitude and distribution of compliance cost savings across the industry, and the broader market impacts.

EPA used specific indicators to assess the impacts of the 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, November 3, 2015);

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

however, for the final rule, EPA compared the values to a baseline that reflects implementation of existing environmental regulations (as of this action), 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 of changes to those 2015 limitations and standards. More specifically, EPA compared the estimated baseline costs to the total cost to industry, and the change in the numbers and capacities of specific EGUs and plants expected to close under the regulatory options (including the final rule, Option A). As a screening tool, EPA also analyzed the ratio of compliance costs to revenue to see how the regulatory options change the number of plants (and their owning entities) that exceed thresholds indicative of financial strain.

In addition to the analyses supporting the economic achievability of the final rule, EPA conducted other analyses to: (1) Characterize other estimated effects of the final rule (*e.g.,* on electricity rates) and (2) meet the requirements of Executive Orders or other statutes (*e.g.,* Executive Order 12866, Regulatory Flexibility Act, Unfunded Mandates Reform Act).

A. Plant-Specific and Industry Total Costs

EPA estimated plant-specific costs to control FGD wastewater and BA transport water discharged at existing EGUs at steam electric power plants to which the ELGs apply.[130] 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 plants would likely make to meet the 2015 rule (for baseline) and the final rule, and estimated the cost to implement those changes. As explained in the Supplemental TDD, the baseline also accounts for announced unit retirements, conversions, and other relevant operational changes that have occurred since EPA promulgated the 2015 rule. EPA thus derived plant-level capital and O&M costs for controlling FGD wastewater and BA transport water using the technologies that form the bases of the 2015 rule, and for the final rule. See Section 5 of the Supplemental TDD for a more detailed description of the methodology EPA used to estimate plant-level costs.

Following the same methodology used for the 2015 rule analysis and 2019 proposal, and consistent with OMB guidance, EPA used a discount rate of seven percent to annualize one-time costs and costs recurring on other than an annual basis over a specific useful life, implementation period, and/or event recurrence period. For capital costs and initial one-time costs, EPA used 20 years. For O&M costs incurred at intervals longer than one year, EPA used the interval as the annualization period (3 years, 5 years, 6 years, 10 years). EPA added annualized capital costs, initial one-time costs, and the non-annual portion of O&M costs to annual O&M costs to derive total annualized plant costs. EPA then calculated total industry costs by summing plant-specific annualized costs. To assess industry costs, EPA considered both pre-tax and after-tax costs. 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 entities and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. 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).

EPA estimated that the final rule will provide cost savings (negative incremental costs) as compared to the costs that the industry would incur under the 2015 rule of $175 million on a pre-tax basis, and $140 million on an after-tax basis. The savings are attributable to less expensive high recycle rate BA systems, lower cost FGD wastewater treatment systems (chemical precipitation and LRTR), and the subcategorization of LUEGUs, high-FGD flow plants, and EGUs permanently ceasing the combustion of coal by December 31, 2028. Additional cost savings are due to the changes in compliance time frames discussed above in Section VII.D.

B. Social Costs

Social costs are the costs of the final rule from the viewpoint of society as a whole, rather than the viewpoint of regulated plants (which are private costs). In calculating social costs, 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 compliance deadlines and therefore the expected technology implementation years vary across plants. EPA performed the social cost analysis over a 27-year period (2021–2047), which combines the length of the period during which plants are anticipated to install the control technologies (which could be as late as 2028) and the useful life of the longest-lived technology installed at any plant (20 years). EPA calculated the social cost of the final rule using both a three percent discount rate and an alternative discount rate of seven percent. For plants that have EGUs permanently ceasing coal combustion during the period of analysis, EPA zeroed out O&M costs in the years following the cessation of coal combustion.

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, EPA did not quantify the incremental increase in the cost to state governments to evaluate and incorporate BPJ into NPDES permits.[131] Consequently, the only category of costs used to calculate social costs are those pre-tax costs estimated for steam electric power plants. Note that the annualized social costs for the seven percent discount rate differ from comparable pre-tax industry compliance costs. The pre-tax industry compliance costs represent the annualized costs of the final rule if they were incurred today (*i.e.,* in 2020), and thus these costs are discounted into social costs which are estimated based on the stream of future costs starting in the year that individual plants are projected to actually comply with the requirements of the final rule under the availability timing proposed in Section VII.D, and as described above, account for changes to costs to reflect EGUs permanently ceasing the combustion of coal during the period of analysis.

EPA estimated that the final rule will provide total annualized social cost savings (as opposed to industry cost savings, as presented above), of $153 million using a seven percent discount rate, and $127 million using a three percent discount rate.

C. Economic Impacts

EPA assessed the economic impacts of the final rule in two ways: (1) A screening-level assessment of the cost impacts on existing EGUs at steam

[130] EPA did not estimate costs for other wastestreams not affected by this final rule.

[131] The sensitivity analysis presented in *Response to Public Comments for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (DCN SE08615) estimated that BPJ could increase costs by up to $0.5 million per year.

electric power plants and the entities that own those plants, based on comparison of costs to revenue; and (2) an assessment of the impact of the final rule within the context of the broader electricity market, which includes an assessment of changes in predicted plant closures attributable to the final rule. The following sections summarize the results of these analyses. The RIA discusses the methods and results in greater detail, including results for other regulatory options EPA considered.

The first set of cost and economic impact analyses—at both the plant 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 power plants incurring those costs (*i.e.,* level of electricity generation and revenue). EPA conducted these analyses for the baseline and the final rule, and then compared these effects to understand the incremental effects of the final rule. 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 plant and EGU level. This second set of analyses provides insight on the impacts of the final rule on steam electric power plants, 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 final rule to a base case that includes the predicted and observed economic and market effects of the 2015 rule and other existing regulations. EPA used results from the screening analysis of plant- and entity-level impacts, together with changes in projected capacity closure from the market model, to understand the impacts of the final rule relative to the baseline.

1. Screening-Level Assessment

EPA conducted a screening-level analysis of the final rule's estimated impact to existing EGUs at steam electric power plants and parent entities based on cost-to-revenue ratios. Although this is a cost savings rule, for analytic convenience and as a worst-case scenario, the Agency assumed that all of the compliance costs in the baseline, and lower compliance costs in the final rule, would be absorbed by the steam electric power plants and their parent entities (and none passed on to consumers). This assumption may overstate the impacts of compliance expenditures in the baseline to the extent that steam electric power plants operating in a regulated market may in fact be able to pass on increases 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 and savings impacts.

a. Plant-Level Cost-to-Revenue Analysis

EPA developed revenue estimates for this analysis using EIA data, then calculated the change in the annualized after-tax costs of the final rule as a percent of baseline annual revenues. See Chapter 4 of the RIA for a more detailed discussion of the methodology used for the plant-level cost-to-revenue analysis, as well as results for other regulatory options EPA considered.

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 plants owned by small entities under guidance in U.S. EPA (2006),[132] the full range of plants incurring costs below one percent of revenue are unlikely to face economic impacts, while plants with costs between one percent and three percent of revenue have a higher chance of facing economic impacts, and plants incurring costs above three percent of revenue have a still higher probability of facing economic impacts.

Under the baseline scenario, which includes the 2015 rule, EPA estimated that 12 plants would incur costs greater than or equal to one percent of revenue, including four plants that would have costs greater than or equal to three percent of revenue, and an additional 96 plants would incur costs that are less than one percent of revenue. For the final rule, EPA estimated that nine plants incur costs greater than or equal to one percent of revenue, including three plants that have costs greater than or equal to three percent of revenue; an additional 100 plants incur costs that are less than one percent of revenue.

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

EPA also assessed the economic impact of the final rule on parent entities. The screening-level cost-to-revenue analysis at the parent entity level provides insight on the impact on those entities that own existing electric generating units at steam electric power plants. In this analysis, the domestic parent entity associated with a given plant is defined as that entity with the largest ownership share in the plant. For each parent entity, EPA compared the incremental change in the total annualized after-tax costs and the total revenue for the entity under the final rule compared with the baseline (*see* Chapter 4 of the RIA for details). Following the methodology employed in the analyses for the 2015 rule and 2019 proposal (80 FR 67838, 84 FR 64620), EPA developed a range of estimates for the number of entities currently owning an EGU at a steam electric power plant, accounting for partial information available for steam electric power plants that are not expected to incur compliance costs to meet the final rule BAT limitations and pretreatment standards.

Similar to the plant-level analysis above, cost-to-revenue ratios provide screening-level indicators of potential economic impacts to the owning entities; higher ratios suggest a higher probability of economic impacts. EPA estimated that the number of entities currently owning EGUs at steam electric power plants ranges from 231 to 459, depending on the assumed ownership structure of plants not incurring costs under the final rule and not explicitly analyzed. EPA estimates that, in the baseline, 225 to 452 parent entities, respectively, would either incur no costs or incur costs that are less than one percent of their revenues (annualized) to meet the 2015 rule BAT limitations and pretreatment standards. Six entities would have costs exceeding 1 percent of revenue, and none of the entities would have costs exceeding three percent of revenue.

Compared to the baseline, the final rule reduces the impacts on the small number of entities incurring costs. Specifically, there are two fewer entities in the one to three percent of revenue category under the final rule that were not in this category at proposal.

2. Electricity Market Impacts

In analyzing the impacts of regulatory actions affecting the electric power sector, 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 EGU-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

[132] 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 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.* (DCN SE09098)

impact of any power plant regulation because of the interdependence of electric EGUs in supplying power to the electric transmission grid. Changes in electricity production costs at some EGUs can have a range of broader market impacts affecting other EGUs, including the likelihood that various units are dispatched. The analysis also provides important insight on steam electric capacity closures (*e.g.,* retirements of EGUs that become uneconomical relative to others), or avoided closures, based on a more detailed analysis of market factors than in the screening-level analyses above. The results further inform EPA's understanding of the potential impacts of the final rule. For the current analyses, EPA used version 6 (v6) of IPM to analyze the impacts of the final rule. IPM v6 is based on an inventory of U.S. utility- and non-utility-owned EGUs and generators that provide power to the integrated electric transmission grid, including plants 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 current regulatory requirements affecting the power sector (*e.g.,* Cross-State Air Pollution Rule (CSAPR) and CSAPR Update Rule, Mercury and Air Toxics Rule (MATS), the 2014 CWA section 316(b) Cooling Water Intake Structure (CWIS) rule, and 2015 CCR and 2020 CCR Part A rules, the final ACE rule, as well as the 2015 ELG rule).

In contrast to the screening-level analyses, which do not account for interdependence of electric EGUs in supplying power to the transmission grid, IPM v6 accounts for potential changes in the generation profile of steam electric and other EGUs and consequent changes in market-level generation costs, as the electric power market responds to changes in generation costs due to the final rule. Additionally, in contrast to the screening-level analyses, in which 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 final rule, EPA estimated changes in the fixed and variable costs for the steam electric power plants and EGUs already incurring costs in the baseline to instead incur costs (or avoid incurring costs) to comply with the final rule. 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, EPA estimated these costs exogenously for each EGU and input these costs into the IPM model as fixed and variable O&M cost adders. In other words, since the IPM code does not include wastewater treatment cost minimization equations, wastewater treatment costs must be calculated outside the model and input separately to be considered during the model run. EPA then ran IPM v6 including these new cost estimates to determine the dispatch of electric EGUs that would meet projected demand at the lowest cost, subject to the same constraints as in the baseline analysis. The estimated changes in plant- and EGU-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 final rule, including closures or avoided closures of steam electric EGUs and plants.

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 power plants); (2) impact on steam electric power plants as a group, and (3) impact on individual steam electric power plants incurring costs. Chapter 5 of the RIA discusses the first analysis; the sections below summarize the last two, which are also further described in Chapter 5 of the RIA. All results presented below are representative of post-compliance modeled market conditions in the years 2028–2033.

a. Impacts on Existing Steam Electric Power Plants

EPA used IPM v6 results for 2030 [133] to assess the potential impact of the final rule on current EGUs at steam electric power plants. The purpose of this analysis is to assess any fleetwide changes from baseline impacts on EGUs at steam electric power plants. Table VIII–3 reports estimated results for current EGUs at steam electric power plants, as a group. 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 plants regulated by 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 to changes in capacity utilization at EGUs and plants whose retirement status does not change.

TABLE VIII–3—ESTIMATED IMPACT OF THE FINAL RULE ON STEAM ELECTRIC POWER PLANTS AS A GROUP AT THE YEAR 2030 COMPARED TO BASELINE

Metric	Baseline value	Change in value from baseline attributable to the final rule	
		Value	Percent
Total capacity (MW)	314,952	800	0.3%
Early retirements or closures [a] (MW)	68,959	−800	−1.2%
Early retirements or closures [a] (number of plants)	62	1	1.6%
Total generation (GWh)	1,475,819	4,160	0.3%
Variable production cost (2018$/MWh)	$25.92	$0.03	0.1%

[133] IPM model year 2030 represents years 2028–2033.

TABLE VIII–3—ESTIMATED IMPACT OF THE FINAL RULE ON STEAM ELECTRIC POWER PLANTS AS A GROUP AT THE YEAR 2030 COMPARED TO BASELINE—Continued

Metric	Baseline value	Change in value from baseline attributable to the final rule	
		Value	Percent
Annual costs (million 2018$)	$57,620	$109	0.2%

[a] Baseline values for early retirements or closures reflect changes from current operations considering the effects of all current regulations and market trends, not solely the 2015 rule. Values for incremental early retirements or closures represent change relative to the baseline, and thus reflect only changes resulting from the cost savings of this final rule. IPM may show partial (unit) or full plant early retirements (closures). It may also show avoided closures (negative closure values) in which an EGU or plant that is projected to close in the baseline is estimated to continue operating in the policy case.

Under the final rule, generation at steam electric power plants is projected to increase by 4,160 GWh (0.3 percent) nationally, when compared to the baseline. IPM v6 projects a net increase in total steam electric capacity by 800 MW or approximately 0.3 percent of total baseline capacity, and one net plant retirement, which results from increased steam electric generation at several other coal-fired power plants in one region (an overall net increase in steam electric generation). See Section 5.2.2.2 in the RIA for details.

These findings suggest that the final rule can be expected to have small economic consequences for the steam electric power plants as a group. For further discussion of closures and related distributional impacts, see Chapter 5 of the RIA.

b. Impacts on Individual Plants Incurring Costs

EPA also analyzed plant-specific changes attributable to the final rule 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 costs plus fuel cost divided by net generation. The analysis of changes in individual plants is detailed in Chapter 5 of the RIA.

The results generally show no change, or less than a one percent reduction or one percent increase for steam electric power plants projected to incur compliance costs under the final rule. Consistent with lower estimated compliance costs under the final rule than the costs the plants would incur under the 2015 rule, a greater number of plants see improving operating conditions under the final rule (*i.e.,* higher capacity utilization or generation, lower variable production costs) than deteriorating conditions when compared to the baseline. Thus, the results for the subset of plants incurring compliance costs further support the conclusion that the effects of the final rule on the steam electric power generating industry will be less than those of the 2015 rule.

IX. Pollutant Loadings

In developing ELGs, EPA typically evaluates the pollutant loading reductions of regulatory options under CWA section 304(b)(1)(A)(BPT), 304(b)(2)(A)(BAT) and 304 (b)(4)(A)(BCT). In estimating pollutant reductions associated with the final rule, EPA took the same approach as described above for plant-specific costs. That is, EPA compared the values to a baseline that reflects implementation of current environmental regulations, including the 2015 rule. In the 2015 rule, the baseline did not reflect pollutant loading reductions for meeting the 2015 rule requirements, as that effluent reduction is what EPA analyzed to support the 2015 rule. Here, the baseline appropriately includes pollutant loading reductions for achieving the 2015 rule requirements as EPA is analyzing the impact resulting from any changes to those requirements. More specifically, EPA considered the change in the pollutant loading reductions associated with the final rule to those projected under the baseline.

The general methodology that EPA used to calculate pollutant loadings is the same as that described in the 2015 rule. 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 BA transport water. 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 BA transport water.[134] For each plant discharging FGD wastewater or BA transport water, EPA used data from the 2009 survey and/or industry-submitted data to determine the discharge flow rates of those wastewaters. To determine the pollutant loadings of the baseline, 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, 2023, 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 2015 CCR rule and 2020 CCR Part A rule. For further discussion of these adjustments, see Sections 6.2.2 and 6.3.2 of the Supplemental TDD, respectively.

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

For those plants that discharge indirectly to POTWs, EPA adjusted the baseline loadings and the loadings associated with the final rule 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 EPA used to calculate pollutant loading reductions, including for the other regulatory options, see Section 6 of the Supplemental TDD.

A. FGD Wastewater

For FGD wastewater, EPA used the average pollutant effluent concentration

[134] Acceptance criteria are presented in Section 6.1 of the Supplemental TDD.

and plant-specific discharge flow rates to estimate the mass pollutant discharge per plant for baseline and for the final rule. 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, EPA reviewed state and EIA data to identify flow rates for new scrubbers that have come online since the 2015 rule. EPA also accounted for increased scrubber recycle rates, which would affect the discharge flow.

EPA assigned pollutant concentrations for each analyte based on the operation of a treatment system designed to comply with the baseline or the final rule. EPA used data compiled for the 2015 rule to characterize untreated FGD purge, chemical precipitation effluent, and CP+HRTR effluent. EPA used data provided by industry to characterize effluent quality for CP+LRTR and membrane filtration effluent under the VIP. In addition, 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 final rule.

EPA received comments on potential errors in the bromide loadings calculations used for the 2019 proposal. EPA agrees with comments identifying conversion errors, as well as comments suggesting updated bromide addition rates and has, therefore, updated its bromide loadings estimates to reflect these changes. Some commenters also expressed preferences for addressing or not addressing iodine as presented in Section XIV(C) below. EPA's rulemaking record contains very limited information about iodine, and publicly available data is more limited and uncertain than data on bromide. However, in response to comments, EPA conducted a mass balance to estimate iodine loadings based on the limited available data. For a more complete discussion of these changes, see Section 6 of the Supplemental TDD.

B. BA Transport Water

EPA estimated baseline and post-compliance loadings for the final rule in Table VII–1 using pollutant concentrations for BA transport water and plant-specific flow rates. 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, EPA also estimated discharge flows associated with the purge from remote MDS operation, based on the EGU capacity and the volume of the remote MDS. Under the baseline, which reflects the 2015 rule limitation of zero discharge, EPA estimated a flow rate of zero.

For the final rule, in response to the administrative petitions discussed in Section IV of this preamble, EPA used a revised set of the 2015 rule analytical data to characterize BA transport water effluent from steam electric power plants. As an example, 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. EPA also updated the data set and incorporated BA transport water sampling data submitted by industry during the final months of the 2015 rulemaking and as part of a voluntary sampling program described in Section VI of this preamble. For a detailed discussion, including for other regulatory options, see Section 6 of the Supplemental TDD.

C. Summary of Incremental Changes of Pollutant Loadings From Final Rule

Compared to the 2015 rule, the final rule is estimated to result in further reductions of approximately 972,000 pounds of pollutants per year. Reductions under the final rule would be realized to the extent that plants choose to meet the limitations based on membrane filtration under the VIP for FGD wastewater. The EPA estimated that, under the final rule, eight plants (13 percent of plants estimated to incur FGD compliance costs) would opt into the VIP program.

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 EPA to consider non-water quality environmental impacts (including energy impacts) associated with ELGs. Accordingly, EPA has considered the potential impact of the final rule 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 meeting the 2015 rule requirements, and EPA has analyzed the incremental impacts resulting from the final rule compared to those projected under the 2015 Rule baseline. In general, 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 and the 2019 proposal. The following summarizes the methodology and results. See Section 7 of the Supplemental TDD for additional details, including analysis of the other regulatory options that EPA considered.

A. Energy Requirements

Steam electric power plants use energy when transporting ash and other solids on or off site, transporting brine off site, operating wastewater treatment systems (*e.g.,* chemical precipitation, biological treatment), or operating ash handling systems. For the final rule, EPA considered whether there would be an associated change in the incremental energy requirements compared to baseline. Therefore, as applicable, EPA estimated the increase in energy usage in megawatt hours (MWh) for equipment added to the plant systems or in consumed fuel (gallons) for transportation/operating equipment for the baseline and final rule. EPA summed the plant-specific estimates to calculate the net overall difference in energy requirements between baseline and the final rule. This section discusses plant-specific energy requirements and does not address electricity reliability of the electric grid. See Section VII.C for discussion of electricity reliability with respect to LUEGUs and EGUs permanently ceasing coal combustion.

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. EPA also estimated the fuel consumption associated with the changes in transportation needed to landfill solid waste and combustion residuals (*e.g.,* ash) of steam electric power plants (on site or off site) and send concentrated brine off site to a centralized waste treatment (CWT) plant. The frequency and distance of transport depend on a plant's location, 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 plant. Table X–1 shows the net change in annual electrical energy usage associated with the final rule compared to 2015 rule baseline, as well as the net change in annual fuel consumption requirements associated with the final rule compared to baseline.

TABLE X–1—ESTIMATED INCREMENTAL CHANGE IN ENERGY REQUIREMENTS ASSOCIATED WITH THE FINAL RULE COMPARED TO 2015 RULE BASELINE

Non-water quality impact	Energy use [a]
Electrical Energy Used (MWh)	−37,200
Fuel Used (Thousand Gallons Per Year)	−1,062,000

[a] Negative values represent a decrease in energy use under the final rule compared to baseline.

B. Air Pollution

The final rule is expected to affect air pollution through three main mechanisms: (1) Changes in auxiliary electricity use by steam electric power plants 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 power plants generate air emissions by operating transport vehicles, such as dump trucks, which release criteria air pollutants and greenhouse gases. A decrease in energy use or vehicle operation would result in decreased air pollution from those sources.

To estimate the net air emissions associated with changes in electrical energy use projected under the final rule compared to the 2015 rule baseline, EPA combined the energy usage estimates with air emission factors associated with electricity production to calculate air emissions associated with the incremental energy requirements. 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 the final rule compared to baseline.

To estimate net air emissions associated with the change in operation of transport vehicles, EPA used the MOVES2014b model to identify air emission factors (grams per mile) for the relevant air pollutants. EPA estimated the annual number of miles that dump trucks moving ash or wastewater treatment solids to on- or off-site landfills would travel under the regulatory options. EPA used these estimates to calculate the net change in air emissions for the final rule compared to the 2015 rule 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 THE FINAL RULE COMPARED TO THE 2015 RULE BASELINE [a]

Non-water quality impact	Change in emissions (tons/year)
NO_X	−21.9
SO_2	−16.8
CO_2	−33,300

[a] Negative values represent a decrease in energy use compared to 2015 Rule baseline.

The modeled output from IPM v6 predicts changes in electricity generation due to compliance costs attributable to the final rule compared to the 2015 rule 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 power plants. A summary of the net change in annual air emissions under the final rule for all three mechanisms is shown in Table X–3. 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 steam electric power plants throughout the United States. For 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 THE FINAL RULE COMPARED TO THE 2015 RULE BASELINE

Non-water quality impact	Change in emissions (million tons)	2018 emissions by electric power generating industry (million tons)
NO_X	0.00067	1.29
SO_2	0.0016	1.41
CO_2	2.67	1,970

C. Solid Waste Generation and Beneficial Use

Steam electric power plants generate solid waste associated with sludge from wastewater treatment systems (*e.g.,* chemical precipitation, biological treatment). EPA estimated the change in the amount of solids generated under the final rule in comparison to the 2015 Rule baseline. For FGD wastewater treatment, the final rule results in an increase in the amount of solid waste generated compared to baseline due to projected implementation of the VIP at eight plants. While BA solids are also generated at steam electric power plants, all of the BA solids accounted for in the waste volumes disposed of in the 2015 rule analysis were suspended solids from combustion, and, therefore, the final rule does not alter the amount of BA or other combustion residuals generated. EPA estimates that plants impacted by the final rule would generate 30,800 more tons of waste per year than plants in the baseline scenario. However, EPA finds that these additional non-water quality environmental impacts are acceptable, as these volumes represent much less than a one percent increase in total waste generation by these plants.

EPA also evaluated the potential impacts of diverting FA from current beneficial uses to encapsulate brine (from membrane filtration) for disposal in landfills. According to the latest American Coal Ash Association (ACAA) survey,[135] most beneficially used FA is replacing Portland cement used to make concrete. As seen by FA sales data in the 2018 EIA–923 Schedule 8A, plants currently discharging FGD wastewater on average sell 34 percent of their FA for beneficial use.[136] Summary statistics of the FA beneficial use percentage for these plants are displayed in Table X–5 below.

TABLE X–5—PERCENT OF FA SOLD FOR BENEFICIAL USE BY PLANTS DISCHARGING FGD WASTEWATER

Statistic	Percent of FA sold for beneficial use
Min	0%
25th percentile	0
Median	13
Mean	34
75th percentile	79
Max	100

In EPA's CCR disposal rule,[137] 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 EPA cannot, with available data, tie specific plants selling their FA to this specific beneficial use, the ACAA data indicate that more than half of the FA beneficially used currently replaces Portland cement in concrete. Therefore, where sale for this particular beneficial use occurs by plants that may otherwise use their FA to encapsulate membrane filtration brine under Option C, EPA finds that would result in unacceptable air and other non-water quality environmental impacts, as detailed in Section VII(B)(1).

D. Changes in Water Use

Steam electric power plants generally use water for handling solid waste, including ash, and for operating wet FGD scrubbers. The BA transport technologies associated with baseline and the final rule for BA transport water eliminate or reduce the volume of water used by wet sluicing BA operating systems. The 2015 rule baseline required 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, EPA estimated the increase in water use for BA handling associated with the final rule compared to baseline as equal to the BA purge flow.

The technology basis for FGD wastewater in the final rule, CP+LRTR, is not expected to reduce or increase the volume of water used. Plants that install a membrane filtration system for FGD wastewater treatment as part of the VIP option are assumed to decrease their 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, EPA estimated the reduction in water use resulting from membrane filtration treatment as equal to the estimated volume of the permeate stream from the membrane filtration system. EPA estimates that plants impacted by the final rule will increase their water use by 3.94 million gallons per day compared to baseline. EPA finds this impact to be acceptable because it represents less than a one percent increase in water use at these plants.

XI. Environmental Assessment

A. Introduction

EPA conducted an environmental assessment for the final rule. The Agency reviewed available literature on the documented environmental and human health effects of the pollutants discharged in steam electric power plant FGD wastewater and BA transport water. EPA conducted modeling to determine the impacts of pollution from the universe of plants to which the final rule applies. For the reasons described in Section VIII of this preamble, the baseline for these analyses appropriately consists of the environmental and human health results of achieving the 2015 rule requirements (the same baseline EPA used to evaluate costs). This assessment compares the potential environmental impacts of the 2015 rule with those of the final rule.

Information from EPA's review of the scientific literature and documented cases of impacts of pollutants discharged in steam electric power plant FGD wastewater and BA transport water on human health and the environment, as well as a description of EPA's modeling methodology and results, are provided in the Supplemental Environmental Assessment (Supplemental EA). The Supplemental EA contains information on literature that EPA has reviewed since the 2015 rule, updates to the modeling methodology and modeling results supporting the analysis for the final rule. The 2015 EA provides information from 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 plant wastewater discharges addressed in the 2015 rule on human health and the environment, as well as a full description of EPA's modeling methodology.

Current scientific literature indicates that untreated steam electric power plant 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 cause detrimental environmental and human health impacts. For additional information, see Section 2 of the Supplemental EA. EPA also considered environmental and human health effects associated with changes in air emissions, solid waste generation, and water withdrawals. Sections X and XII of this preamble discuss these effects.

B. Updates to the Environmental Assessment Methodology

The environmental assessment modeling for this final rule consisted of the steady-state, national-scale immediate receiving water (IRW) model that EPA used to evaluate the direct and indirect discharges from steam electric power plants for the 2019 proposal, the 2015 rule and 2015 CCR rule.[138] The model focused on impacts within the immediate surface waters where the discharges occurred (the closest segments of approximately 0.25 miles to 5 miles long). EPA also modeled receiving water concentrations downstream from steam electric power plant 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, EPA retained the updates and improvements to several input parameters for the IRW model from the 2019 proposal, including receiving water boundaries and volumetric flow data from the National Hydrography Dataset Plus (NHDPlus) Version 2, updated national recommended water quality criteria (NRWQC) for cadmium and selenium, updated benchmarks for ecological impacts in benthic sediment, and an updated bioconcentration factor for cadmium.

[135] Available online at: *https://www.acaa-usa.org/Portals/9/Files/PDFs/2018-Survey-Results.pdf* (DCN SE09099).

[136] Available online at: *https://www.eia.gov/electricity/data/eia923/*.

[137] Available online at: *http://www.regulations.gov Docket ID:* EPA–HQ–RCRA–2009–0640.

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

C. Outputs From the Environmental Assessment

EPA estimates small environmental and ecological changes associated with changes in pollutant loadings for the final rule as compared to the baseline, including small changes in impacts to wildlife and humans. 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.

As described in the Supplemental EA, 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. EPA modeled changes in discharged toxic, bioaccumulative pollutants from both FGD wastewater and BA transport water into rivers and streams and lakes, including reservoirs. EPA also addressed environmental impacts from nutrients in the Supplemental EA, as well as 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 today's final rule compared to the 2015 rule. All of the modeled changes relative to the baseline are small.

XII. Benefits Analysis

This section summarizes EPA's national estimates of the changes in social benefits expected to result from estimated changes in steam electric power plant wastewater discharges described in Section IX of this preamble and the resultant environmental effects summarized in Section XI of this preamble. 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 EPA for the 2015 rule and the 2019 proposal, but with revised inputs and assumptions that reflect updated data. For the final rule, EPA used the same methodology developed for the Affordable Clean Energy (ACE) rule (84 FR 32520, July 8, 2019) to estimate human health effects due to changes in pollutant air emissions relative to the baseline.

A. Categories of Benefits Analyzed

Table XII–1 summarizes benefit categories associated with the final rule and notes which categories EPA was able to quantify and monetize. Analyzed benefits fall into five 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, EPA was able to assess changes in the benefits projected for today's final rule with varying degrees of completeness and rigor. Where possible, 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 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 final rule relative to the baseline.

TABLE XII–1—SUMMARY OF BENEFITS CATEGORIES ASSOCIATED WITH FINAL RULE

Benefit category	Quantified and monetized	Quantified, but not monetized	Neither quantified nor monetized
Human Health Effects From Surface Water Quality Changes			
Changes in halogen levels in drinking water treatment plant source waters		✓	
Changes in human health effects (*e.g.,* bladder cancer) associated with halogenated disinfection byproduct exposure via 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) due to exposure to arsenic, lead, cadmium, and other toxics via 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 Condition and Recreational Use Effects 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 water;[a] and non-use value (existence, option, and bequest value from improved ecosystem health).[a]	✓		
Changes in protection of threatened and endangered species		✓	
Changes in sediment contamination			✓

TABLE XII–1—SUMMARY OF BENEFITS CATEGORIES ASSOCIATED WITH FINAL RULE—Continued

Benefit category	Quantified and monetized	Quantified, but not monetized	Neither quantified nor monetized
Market and Productivity Effects			
Changes in water treatment costs for municipal drinking water, irrigation water, and industrial process water			✓
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 Quality-Related Effects			
Changes in human morbidity and mortality from changes in exposure to NO_X, SO_2, O_3, and particulate matter ($PM_{2.5}$)	✓		
Changes in ecosystem effects; visibility impairment; and human health effects from direct exposure to NO_2, SO_2, and HAP			✓
Changes in climate change impacts from CO_2 emissions	✓		
Changes in Water Withdrawal			
Changes in the availability of groundwater resources	✓		
Changes in the availability of surface water resources			✓
Changes in impingement and entrainment of aquatic organisms			✓

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

The following section summarizes EPA's analysis of the benefit categories that the Agency was able to quantify and/or monetize (identified in the first and second columns of Table XII–1). Benefits are a function of the changes in pollutant loadings under the final rule and the timing of the rule's implementation. The final rule would also affect additional benefit categories that the Agency was not able to quantify or monetize. The BCA report further describes additional qualitative and nonmonetized benefits.

B. Quantification and Monetization of Benefits

1. Changes in Human Health Effects From Surface Water Quality Changes

Changes in pollutant discharges from steam electric power plants affect human health in multiple ways. Exposure to pollutants in steam electric power plant discharges via consumption of fish from affected waters can cause a wide variety of adverse health effects, including cancer, kidney damage, nervous system damage, liver damage, circulatory damage, vomiting, diarrhea, brain damage, IQ loss, fatigue, irritability, and many others. Exposure to drinking water containing halogenated disinfection byproducts could cause adverse health effects such as cancer and reproductive and fetal development issues. Because the final rule is expected to change discharges of steam electric pollutants into surface waters, it may alter incidence of associated health effects, even if by small amounts. EPA's analyses of human health effects, detailed in Chapters 4 and 5 of the BCA report, find that the incremental changes in exposure between the baseline and the final rule are minimal compared to the estimates of absolute changes in exposure for those same pollutants under the 2015 rule.

Due to data limitations and uncertainties, EPA is able to monetize only a subset of the changes in health effects associated with changes in pollutant discharges under the final rule relative to the baseline. EPA's analysis first estimated the changes in the expected number of individuals experiencing adverse health effects in the populations affected by exposure to discharged pollutants under the final rule relative to the baseline. EPA then estimated the value of these changes by using different monetization methods for different health benefit endpoints.

EPA estimated changes in health risks from the consumption of contaminated fish from waterbodies within 50 miles of households. EPA used Census Block Group population data and state-specific average fishing participation rates to estimate the exposed population. EPA used population cohort-specific fish consumption rates and waterbody-specific fish tissue concentration estimates to calculate potential exposure to pollutants from steam electric power plants. Cohorts were defined by age, gender, race/ethnicity, and fishing mode (recreational or subsistence). EPA used these data to quantify and monetize changes in the following four 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 quantified and monetized health outcomes associated with consumption of contaminated fish tissue under the final rule relative to the baseline. In addition, EPA estimates no changes in cancer incidence due to arsenic exposure via fish consumption under the final rule relative to the baseline. Accordingly, EPA estimates no change in social benefits for this health endpoint. Chapter 5 of the BCA report provides additional detail on EPA's methodologies.

TABLE XII–2—ESTIMATED MONETARY VALUES OF CHANGES IN HUMAN HEALTH EFFECTS UNDER THE FINAL RULE COMPARED TO BASELINE

[Millions of 2018$, annualized][a]

Human health benefits	3% Discount rate	7% Discount rate
Reduced Lead Exposure for Children	−$0.02	[b] <$0.00
Reduced Mercury Exposure for Children	−$0.32	−$0.11
Total Monetized Benefits	−$0.34	−$0.11

[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.

There is evidence of linkages between adverse human health effects, including bladder cancer, and exposure to halogenated disinfection byproducts in drinking water. Reductions in halogen levels in source waters for drinking water treatment plants can contribute to reductions in halogenated disinfection byproduct levels in drinking water. EPA analyzed the populations served by drinking water treatment plants with intakes on surface waters to which steam electric power plants discharge. EPA used Safe Drinking Water Information System (SDWIS) and U.S. Census data to estimate the exposed population. EPA estimated reductions in source water halogen concentrations under this final rule relative to the baseline. EPA estimates that following implementation of wastewater treatment upgrades to meet the revised ELGs (*i.e.,* starting in 2029), 323 drinking water treatment plants serving a total population of 7.3 million people will experience a reduction in source water halogen concentrations under the final rule relative to baseline. These halogen reduction benefits derive from projected plant participation in the VIP.[139] Additional details on this analysis, including a discussion of uncertainties, are provided in Chapter 4 of the BCA report.

2. Ecological Condition and Recreational Use Effects From Changes in Surface Water Quality

EPA evaluated whether the final rule 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 conditions could change under the final rule, 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 final rule 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.

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 water quality suitable for certain uses. The WQI includes seven parameters: Dissolved oxygen, biochemical oxygen demand, fecal coliform, total nitrogen, total phosphorus, suspended solids, and an aggregate subindex for toxics. For the purposes of this analysis, EPA modeled changes in four of these parameters, and held the remaining parameters (dissolved oxygen, biochemical oxygen demand, and fecal coliform) constant. Relative to baseline, EPA estimates that the final rule will result in small reductions in water quality during the period being analyzed. During the 2021 though 2028 time period, the change in WQI is uniformly negative or zero, with surface water segment-level changes ranging from −5.8 to 0.0 (median change is -3.8×10^{-4}). From 2029 through 2047, the change in WQI is positive in some segments, and segment level WQI changes overall range from −0.7 to 1.5 (median change is -8.1×10^{-5}). The positive changes in WQI in some reaches derive from projected plant participation in the VIP.

EPA estimated the change in monetized benefit values using an updated version of the meta-regressions of surface water valuation studies used in the benefit analysis for the 2015 rule and 2019 proposal. The meta-regressions quantify average household willingness to pay (WTP) for incremental improvements in surface water quality. This WTP is the maximum amount of money a person is willing to give up for a given improvement in water quality. Chapter 6 of the BCA report provides additional detail on the valuation methodology. Overall, the final rule is estimated to result in small reductions in water quality relative to baseline, which is reflected in negative average annual household WTP values ranging from −$0.40 to −$0.20 (central estimate −$0.31).

Table XII–3 presents annualized total WTP values for water quality changes associated with modified toxic pollutant (arsenic, cadmium, chromium, copper, lead, mercury, selenium, zinc, and nickel), nutrient pollutant (phosphorus and nitrogen), and sediment pollutant discharges to approximately 10,610 reach miles affected by the final rule. An estimated 82.4 million households reside in census block groups within 100 miles of affected reaches. The central tendency estimates of the total annualized benefits of water quality changes for the final rule range from −$12.5 million (7 percent discount rate) to −$11.8 million (3 percent discount rate).

[139] Estimated halogen concentrations increase relative to baseline for some drinking water treatment plants due to BA requirements under this final rule, but the magnitude of these increases is generally much smaller than the magnitude of decreases at plants experiencing reductions.

TABLE XII–3—ESTIMATED TOTAL WILLINGNESS-TO-PAY FOR WATER QUALITY CHANGES UNDER THE FINAL RULE COMPARED TO BASELINE [a]

[Millions of 2018$; annualized]

Number of affected households (millions)	Total willingness-to-pay for water quality changes					
	3% discount rate			7% discount rate		
	Low	Central	High	Low	Central	High
82.4	−$15.3	−$11.8	−$7.4	−$16.4	−$12.5	−$8.0

[a] Negative values represent forgone benefits.

3. Effects on Threatened and Endangered Species

EPA assessed the potential for impacts on threatened and endangered (T&E) species, both aquatic and terrestrial, relative to the baseline, by analyzing the overlap between waters expected to change their wildlife national recommended water quality criteria (NRWQC) exceedance status under the final rule and the known habitat ranges of T&E species listed under the Endangered Species Act. 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. EPA estimated that there are 194 species whose known habitat range overlaps with surface waters that receive discharges from steam electric power plants. Five of the 194 T&E species have habitat ranges that intersect with waters that EPA estimates have changes in NRWQC exceedances under the final rule relative to the baseline, four of which correspond to estimated increases in NRWQC exceedances during the 2021–2028 period, and one of which corresponds to an estimated reduction in NRWQC exceedances starting in 2029 following implementation of wastewater treatment technologies to achieve the revised limitations. Principal sources of uncertainty in this analysis include the specifics of how the final rule could impact T&E species (*e.g.,* exposure levels, species reactions to exposure levels), exact species spatial distributions, and additional species that were not considered. Chapter 7 of the BCA report provides additional details on EPA's methodology.

4. Changes in Ability to Market Coal Combustion Byproducts

The final rule could affect the ability of steam electric power plants to market coal combustion byproducts for beneficial use by converting from wet to dry handling of BA. In particular, EPA evaluated the potential effects of changes in marketability of BA as a substitute for sand and gravel in fill applications. EPA estimates that the final rule will affect the quantity of BA handled wet relative to the baseline. The estimated increase in BA handled wet is small (total of 246,871 tons per year at five plants). Given the small magnitude of these changes and the uncertainty associated with projecting plant-specific changes in marketed ash, EPA did not to monetize this benefit category in the final rule analysis. See Chapter 2 in the BCA report for additional details.

5. Changes in Dredging Costs

The final rule would affect discharge of multiple pollutants, including sediment, thereby changing the rate of sediment deposition in 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 liable to reduced functionality due to sediment buildup, 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, flood control, hydropower supply, and recreation. Streams and rivers can carry sediment into reservoirs, where it can settle and cause buildup of sediment layers. Sedimentation reduces reservoir capacity and useful life unless measures such as dredging are taken to reclaim capacity. Chapter 10 of the BCA report provides additional details on EPA's methodology for this benefit category.

EPA estimates that sediment deposition in navigable waterways and reservoirs will increase under the final rule relative to baseline, increasing maintenance dredging costs by less than $0.01 million (3 or 7 percent discount rates).

6. Changes in Air Quality-Related Effects

EPA expects the final rule will affect air pollution through three main mechanisms: (1) Changes in auxiliary electricity use by steam electric power plants to operate wastewater treatment, ash handling, and other systems that EPA predicts plants would use under the final rule; (2) changes in transportation-related air emissions due to changes in trucking of CCR waste to landfills; and (3) changes in the profile of electricity generation due to changes in costs to generate electricity at steam electric power plants affected by the final rule.

Changes in the electricity generation profile can increase or decrease air pollutant emissions because emission factors vary for different types of electric EGUs. For this analysis, the changes in air emissions relative to the baseline are based on the change in dispatch of generation units as projected by IPM v6 given the overlaying of costs for complying with the final rule onto steam electric EGUs' 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.

EPA evaluated potential effects resulting from net changes in air emissions of three pollutants: NO_X, SO_2, primary $PM_{2.5}$, and CO_2. NO_X and SO_X are precursors to fine particles sized 2.5 microns and smaller ($PM_{2.5}$) and NO_X is an ozone precursor. These air pollutants cause 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 and school days, and acute respiratory symptoms.[140] CO_2 is a key greenhouse

[140] U.S. EPA. Integrated Science Assessment (ISA) for Particulate Matter (Final Report, 2009). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–08/139F, 2009; U.S. EPA. Integrated Science Assessment for Particulate Matter (Final Report, 2019), U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–19/188; U.S. EPA. Integrated Science Assessment for Ozone and

gas linked to a wide range of domestic effects. Other than mercury (Hg) and hydrogen chloride (HCl) emissions, EPA did not estimate changes in any other air pollutants (*e.g.,* carbon monoxide) emissions that may occur as a result of the final rule due to methodology and resource limitations.

Table XII–4 shows the changes in emissions of CO_2, NO_X, SO_2, and primary $PM_{2.5}$ based on the estimated changes in the profile of electricity generation, including increased generation from coal-fired EGUs (see Table VIII–3) under the final rule relative to baseline.

EPA estimated the monetized value of human health benefits among populations exposed to changes in $PM_{2.5}$ and ozone. The final rule is expected to alter the emissions of primary $PM_{2.5}$, SO_2 and NO_X, which will in turn affect the level of $PM_{2.5}$ and ozone in the atmosphere. Using photochemical modeling, EPA predicted the change in the annual average $PM_{2.5}$ and summer season ozone across the U.S. EPA next quantified the human health impacts and economic value of these changes in air quality using the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP–CE). EPA quantified effects using concentration-response parameters which are consistent with those employed by the Agency in the PM NAAQS, Ozone NAAQS, and ACE RIAs (U.S. EPA, 2012; 2015; 2019).

To estimate the climate benefits associated with changes in CO_2 emissions, EPA applied a measure of the domestic social cost of carbon (SC–CO_2). The SC–CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. The SC–CO_2 estimates used in the analysis for this final rule focus on the direct impacts of climate change that are anticipated to occur within U.S. borders.

Table XII–5 shows the total annualized monetary values associated with changes in emissions of primary $PM_{2.5}$, SO_2 and NO_X under the final rule. To give readers insight to the distribution of estimated benefits displayed in Table XII–5, EPA also reports the PM benefits according to alternative concentration cut-points and concentration-response parameters. EPA uses two long-term epidemiological studies to estimate risk, Krewski et al. (2009) [141] and Lepeule et al. (2012).[142] Small shares of avoided $PM_{2.5}$-related premature deaths occur above the annual mean $PM_{2.5}$ NAAQS of 12 mg/m^3, with percentages depending on the year and epidemiological studies. The shares range from less than 1 percent to up to 2 percent based on Lepeule et al. (2012) and from less than 1 percent to 3 percent based on Krewski et al. (2009).

Table XII–6 reports the combined human health benefits and domestic climate benefits attributable to changes in SO_2, NO_X, primary $PM_{2.5}$, and CO_2 emissions estimated with 3 percent and 7 percent discount rates. This table reports the air pollution effects calculated using $PM_{2.5}$ log-linear no threshold concentration-response functions that quantify risk associated with the full range of $PM_{2.5}$ exposures experienced by the population (U.S. EPA, 2009; [143] U.S. EPA, 2011; [144] NRC, 2002).[145]

In general, EPA is more confident in the size of the risks estimated from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, EPA is less confident in the risk EPA estimates from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.[146] Furthermore, when setting the 2012 PM NAAQS, the former EPA Administrator also acknowledged greater uncertainty in specifying the ''magnitude and significance'' of PM-related health risks at PM concentrations below the NAAQS. As noted in the preamble to the 2012 PM NAAQS final rule, ''EPA concludes that it is not appropriate to place as much confidence in the magnitude and significance of the associations over the lower percentiles of the distribution in each study as at and around the long-term mean concentration.'' [147]

Estimates of monetized co-benefits shown here do not include several important benefit categories, such as direct exposure to SO_2, NO_X, and HAPs including mercury and hydrogen chloride. Although EPA does not have sufficient information or modeling available to provide monetized estimates of changes in exposure to these pollutants for the final rule, EPA includes a discussion of these unquantified benefits in the BCA. For more information on the benefits analysis, see Chapter 8 of the BCA Report.

TABLE XII–4—ESTIMATED CHANGES IN AIR POLLUTANT EMISSIONS FROM CHANGES IN ELECTRICITY GENERATION PROFILE UNDER THE FINAL RULE COMPARED TO BASELINE [a]

Year	CO_2 (million short tons/year)	NO_X (thousand short tons/year)	SO_2 (thousand short tons/year)	Primary $PM_{2.5}$ (thousand short tons/year)
2021	−0.079	−0.25	−1.4	−0.028
2023	2.9	3.0	−2.6	0.45
2025	2.2	1.6	−0.70	0.91
2030	2.7	0.69	1.7	0.48
2035	0.88	−0.57	1.8	0.81

Related Photochemical Oxidants (Final Report, 2013). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–10/076F; and U.S. EPA. Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final Report, 2020) U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–20/012.

[141] Krewski, D., Jerrett, M., Burnett, R.T., Ma, R., Hughes, E., Shi, Y., Turner, M.C., Pope, C.A., Thurston, G., Calle, E.E., Thun, M.J., Beckerman, B., DeLuca, P., Finkelstein, N., Ito, K., Moore, D.K., Newbold, K.B., Ramsay, T., Ross, Z., Shin, H., Tempalski, B., 2009. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. Res. Rep. Health. Eff. Inst. 5–114–36.

[142] Lepeule, J., Laden, F., Dockery, D., Schwartz, J., 2012. Chronic exposure to fine particles and mortality: An extended follow-up of the Harvard Six Cities study from 1974 to 2009. Environ. Health Perspect. *https://doi.org/10.1289/ehp.1104660.*

[143] U.S. EPA, 2009. Integrated Science Assessment for Particulate Matter. U.S. Environmental Protection Agency, National Center for Environmental Assessment, Research Triangle Park, NC.

[144] U.S. EPA, 2011. Policy Assessment for the Review of the Particulate Matter National Ambient Air Quality Standards. Research Triangle Park, NC.

[145] NRC, 2002. Estimating the Public Health Benefits of Proposed Air Pollution Regulations. National Research Council. Washington, DC.

[146] The **Federal Register** notice for the 2012 PM NAAQS states, ''In considering this additional population level information, the Administrator recognizes that, in general, the confidence in the magnitude and significance of an association identified in a study is strongest at and around the long-term mean concentration for the air quality distribution, as this represents the part of the distribution in which the data in any given study are generally most concentrated. She also recognizes that the degree of confidence decreases as one moves towards the lower part of the distribution.'' See 78 FR 3159 (Jan. 15, 2013).

[147] *See* 78 FR 3154, January 15, 2013.

TABLE XII–4—ESTIMATED CHANGES IN AIR POLLUTANT EMISSIONS FROM CHANGES IN ELECTRICITY GENERATION PROFILE UNDER THE FINAL RULE COMPARED TO BASELINE [a]—Continued

Year	CO_2 (million short tons/year)	NO_X (thousand short tons/year)	SO_2 (thousand short tons/year)	Primary $PM_{2.5}$ (thousand short tons/year)
2040	1.0	−1.6	−2.9	−0.22
2045	2.8	0.15	0.92	0.44

[a] All values in this table are rounded to two significant figures. Negative values represent emission reductions and positive values represent emission increases.

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Table XII-5. Estimated Economic Value of Avoided $PM_{2.5}$ and Ozone-attributable Deaths and Illnesses for the Final Rule Compared to Baseline Using Alternative Approaches to Representing $PM_{2.5}$ Effects (Millions of 2018$)[a]

Discount Rate	Approach	Ozone Benefits plus $PM_{2.5}$ Benefits, Millions of 2018$ (95% Confidence Interval)														
		2025			2030			2035			2040			2045		
3%	No-threshold model[b]	$21 (-$29 to $86)	to	$33 (-$110 to $200)	-$41 (-$120 to $0.33)	to	-$91 (-$270 to $2.5)	-$120 (-$330 to -$4.4)	to	-$260 (-$760 to -$7.9)	$320 ($31 to $870)	to	$740 ($66 to $2100)	-$81 (-$250 to $19)	to	-$170 (-$570 to $64)
	Limited to above LML[c]	$34 (-$28 to $120)	to	-$49 (-$150 to $4.4)	-$0.4 (-$6.2 to $5.5)	to	-$110 (-$310 to $4.5)	-$96 (-$270 to -$2)	to	-$220 (-$630 to -$3)	$300 ($29 to $830)	to	$490 ($44 to $1400)	-$60 (-$190 to $22)	to	-$150 (-$500 to $69)
	Effects above NAAQS[d]	-$9.2 (-$32 to $4.9)	to	-$35 (-$110 to $5.6)	$0.43 (-$3.9 to $5.6)	to	$3.2 (-$3.7 to $14)	-$1.5 (-$9.9 to $6.7)	to	$1.6 (-$9.7 to $16)	$34 ($4.3 to $91)	to	$93 ($9 to $270)	$6.8 (-$7.1 to $28)	to	$25 (-$5.6 to $84)
7%	No-threshold model[b]	$18 (-$30 to $78)	to	$26 (-$110 to $180)	-$37 (-$100 to $0.72)	to	-$82 (-$240 to $3.3)	-$110 (-$290 to -$3.3)	to	-$240 (-$680 to -$5.6)	$290 ($28 to $790)	to	$670 ($60 to $1900)	-$73 (-$220 to $20)	to	-$150 (-$510 to $66)
	Limited to above LML[c]	$29 (-$29 to $110)	to	-$48 (-$150 to $4)	-$0.35 (-$5.9 to $5.4)	to	-$95 (-$280 to $5.1)	-$86 (-$240 to -$1.1)	to	-$190 (-$570 to -$1.1)	$280 ($27 to $750)	to	$450 ($41 to $1300)	-$53 (-$170 to $22)	to	-$130 (-$450 to $70)
	Effects above NAAQS[d]	-$9.3 (-$32 to $4.6)	to	-$35 (-$110 to $5.1)	$0.4 (-$3.9 to $5.4)	to	$3.2 (-$3.7 to $14)	-$1.4 (-$9.8 to $6.7)	to	$1.6 (-$9.6 to $16)	$33 ($4.3 to $90)	to	$92 ($8.9 to $270)	$6.8 (-$7 to $28)	to	$25 (-$5.6 to $84)

[a] All values in this table are rounded to two significant figures. Negative values represent forgone benefits and positive values represent realized benefits.

[b] $PM_{2.5}$ effects quantified using a no-threshold model. Low end of range reflects dollar value of effects quantified using concentration-response parameter from Krewski et al. (2009) and Smith et al. (2008) studies; upper end quantified using parameters from Lepeule et al. (2012) and Jerrett et al. (2009). Full range of ozone effects is included.

[c] $PM_{2.5}$ effects quantified at or above the Lowest Measured Level of each long-term epidemiological study. Low end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 $\mu g/m^3$); high end of range reflects dollar value of effects quantified down to LML of Lepeule et al. (2012) study (8 $\mu g/m^3$). Full range of ozone effects is still included.

[d] $PM_{2.5}$ effects only quantified at or above the annual mean of 12 $\mu g/m^3$ to provide insight regarding the fraction of benefits occurring above the NAAQS. Range reflects effects quantified using concentration-response parameters from Smith et al. (2008) study at the low end and Jerrett et al. (2009) at the high end. Full range of ozone effects is still included.

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TABLE XII–6—ESTIMATED MONETIZED BENEFITS FROM CHANGES IN AIR EMISSIONS FOR THE FINAL RULE COMPARED TO BASELINE [a]

[Millions 2018$; annualized]

Benefit category	3% Discount rate		7% Discount rate	
	Lower bound [b]	Upper bound [c]	Lower bound [b]	Upper bound [c]
Climate change	−$14		−2.3	
Human health	$28	$65	$25	$56
Total	14	51	23	54

[a] All values in this table are rounded to two significant figures. Negative values represent forgone benefits and positive values represent realized benefits. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The human health benefits reflect the sum of the $PM_{2.5}$ and ozone benefits and reflect the range based on adult mortality functions. The health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment.

[b] Lower bound is based on human health benefit point estimates using Krewski et al. (2009) for $PM_{2.5}$ and Smith et al (2009) for ozone.

[c] Upper bound is based on human health benefit point estimates using Lepeule et al. (2012) for $PM_{2.5}$ and Jerrett et al. (2009) for ozone.

7. Changes in Water Withdrawals

Steam electric power plants use water for handling BA and operating wet FGD scrubbers. By changing the use of water in sluicing operations or prompting the recycling of water in FGD wastewater treatment systems, the final rule may affect the amount of water withdrawn from surface waters or aquifers. Using the same methodology used for the 2015 rule, EPA estimated the monetary value of increased groundwater withdrawals based on increased costs of groundwater supply. The final rule is expected to increase water withdrawal from aquifers relative to baseline. EPA multiplied the increase in groundwater withdrawal (in gallons per year) by water costs of approximately $1,347 per acre-foot (326,000 gallons; 2018$). Chapter 9 of the BCA report provides the details of this analysis. EPA estimates the changes in annualized benefits of increased groundwater withdrawals are −$0.01 million (3 percent and 7 percent discount rates). Due to data limitations, 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, EPA estimated the total monetary value of annualized benefits of the final rule for all monetized categories. Table XII–7 summarizes the total annualized monetary value of social welfare effects using 3 percent and 7 percent discount rates. The total monetary value of benefits under the final rule range from −$1.7 million to $43.3 million using a 3 percent discount rate and from $6.5 million to $45.9 million using a 7 percent discount rate.

TABLE XII–7—SUMMARY OF TOTAL ANNUALIZED BENEFITS OF THE FINAL RULE

[Millions of 2018$; annualized] [a]

Benefit category	3% Discount rate	7% Discount rate
Human Health	−$0.3	−$0.1
Changes in IQ losses in children from exposure to lead [b]	<$0.0	<$0.0
Changes in IQ losses in children from exposure to mercury	−$0.3	−$0.1
Ecological Conditions and Recreational Uses Changes	−$15.3 to −$7.4	−$16.4 to −$8.0
Use and nonuse values for water quality changes [c]	−$15.3 to −$7.4	−$16.4 to −$8.0
Market and Productivity	<$0.0	<$0.0
Changes in dredging costs [b]	<$0.0	<$0.0
Changes in water withdrawals [b]	<$0.0	<$0.0
Air Quality-related effects	$14 to $51	$23 to $54
Domestic climate benefits [d]	−$14	−$2.3
Health benefits [d e]	$28 to $65	$25 to $56
Total Monetized Benefits [f]	−$1.7 to $43.3	$6.5 to $45.9

[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 range reflects the lower and upper bound willingness-to-pay estimates.

[d] Values for air-quality related effects are rounded to two significant figures.

[e] The range reflects the lower and upper bound estimates of human health effects from changes in $PM_{2.5}$ and ozone levels.

[f] Values for individual benefit categories may not sum to the totals due to independent rounding.

D. Unmonetized Benefits

The monetary value of the final rule's effects on social welfare does not account for all anticipated effects of the final rule because, as described above, EPA is unable to monetize certain benefit categories. Examples of effects not reflected in the monetary estimates include changes in bladder cancer incidence and other human health effects associated with changes in drinking water disinfection byproduct levels; changes in ecosystem, visibility, and human health effects due to direct exposure to NO_X, HAP, and SO_2 air emissions; changes in certain non-cancer human health risks (*e.g.,* effects of cadmium on kidney functions and bone density); impacts of pollutant discharge changes on threatened and endangered species; and ash marketability changes. The BCA report discusses changes in these effects qualitatively and indicates their potential magnitude where possible.

XIII. Development of Effluent Limitations and Standards

A. FGD Wastewater

Consistent with the proposal, EPA is finalizing several sets of new, concentration-based, numeric effluent limitations and pretreatment standards that apply to discharged FGD wastewater from existing sources.[148] The specific limitations that apply to any particular plant are determined by whether it qualifies for one of the rule's subcategories or whether it chooses to participate in the VIP. EPA developed the numeric effluent limitations and pretreatment standards in this rule using long-term average effluent values and variability factors that account for variations in performance at well-operated plants that employ the technologies that constitute the bases for control. 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 F.2d 177 (5th Cir. 1989); *Nat'l Wildlife Fed'n* v. *EPA,* 286 F.3d 554 (D.C. Cir. 2002). 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 as 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

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 plant that designs and operates its treatment to achieve the long-term average performance that EPA's statistical analyses show the BAT/PSES technology can attain (*i.e.,* the mean of the underlying statistical distribution of daily effluent values). EPA recognizes that variability around the long-term average occurs during normal operations. This variability means that plants 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, EPA has established the daily maximum limitation. A plant consistently discharging at a level near the daily maximum limitation would be symptomatic of a plant that is *not* 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.

EPA's objective in establishing monthly average limitations is to provide an additional restriction to help ensure that plants target their average discharges to achieve the long-term average. The monthly average limitation requires dischargers to provide ongoing control that supplements controls imposed by the daily maximum limitation. In order to meet the monthly average limitation, a plant 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, EPA qualitatively reviews all the data related to effluent treatment to identify data that represent proper operation of the technology that forms the basis for the limitations. EPA typically uses four criteria to assess the data. The first criterion requires that the plants have the model treatment technology identified as the basis for effluent limitations (*e.g.,* CP + LRTR) and demonstrate consistently diligent and optimal operation. Application of this criterion typically eliminates any plant with treatment other than the model technology. EPA generally determines whether a plant meets this criterion based on site visits, discussions with plant management, and/or comparison to the characteristics, operation, and performance of treatment systems at other plants. EPA reviews available information to determine whether data submitted were representative of normal operating conditions for the plant and equipment. As a result of this review, EPA typically excludes the data from plants that have not optimized the performance of their treatment systems.

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 EPA selecting those plants 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 EPA is establishing 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), EPA excludes the data for that pollutant at that plant 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 analytical method). Also, 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, EPA may evaluate the pollutant concentrations, analytical methods and the associated quality control/quality assurance data, flow values, mass loading, plant logs, test reports, and other available information. As part of this evaluation, EPA reviews the process or treatment conditions that may have resulted in

[148] Effluent limitations for EGUs with nameplate capacity of 50 MW or smaller and for EGUs 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.

extreme values (high and low). As a consequence of this review, 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 EPA's review of data from the initial commissioning period of treatment systems and startup periods of pilot test equipment. Most industries incur commissioning periods during which adjustments must be made to newly installed 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'' by the plant staff and equipment and chemical vendors. They work together 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, such as clarifier sludge wasting protocols. It may also take time for treatment system operators to gain expertise in 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, EPA generally excludes such data in developing the limitations.[149]

[149] 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 vary widely 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.

3. Data Used To Calculate Limitations and Standards

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 rule. The effluent limitations and pretreatment standards for the low utilization subcategory and high FGD 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 for plants not in those subcategories, and for the VIP, were derived from a statistical analysis of effluent data collected by plants during extended testing of the LRTR technology and membrane filtration technology, respectively. The duration of the test programs at these plants varied from approximately one month for membranes to more than a year for LRTR, enabling 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 different climate conditions.

During the development of the final limitations and pretreatment standards, 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 conditions 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 volumes of non-FGD wastewater prior to entering 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

EPA received numerous comments on the development of the CP+LRTR limitations. First, the Agency received comments arguing that the limitations calculations should have included or excluded individual data points or data sets, for a number of reasons. For example, one commenter asserted that plant 2027's mercury data set used an improper method under EPA's criteria, another asserted that plant 2066 had unrepresentative influent pollutant concentrations, and another asserted that excluded data points from plant 2019 were actually representative of potential operating conditions. EPA also received comments that limitations should be developed with data from full-scale systems and that nitrate/nitrite limitations are unnecessary for a well-operated biological treatment system. Finally, EPA was aware of an additional data set which it discussed at proposal, and had requested, but which the Agency did not receive until after the comment period closed.

EPA agrees with comments that the mercury data set for Plant 2027 did not use an EPA-approved method and that the method used had an improper mercury detection limitation (not sufficiently sensitive). Accordingly, the Agency has excluded those mercury data from its calculation of the final mercury limitations. With respect to plant 2066, EPA compared this plant's data to other plants and found that it neither had the lowest influent concentrations nor met the test for statistical outliers.[150] In the absence of a valid statistical rationale for excluding these data, which meet all of the criteria detailed above, EPA used these data in its calculations of the final limitations. With respect to plant 2019, the data in question were excluded by the Agency because that data was collected during periods where the pilot study operators attempted to test the operating limitations of (*i.e.,* ''break'') the biological treatment system by spiking the influent with large quantities of constituents and/or drastically altering the flow. Contrary to the assertions by commenters that there could be operating conditions like these in the future, these pilot conditions were intentionally designed not to be representative of the BAT/PSES level of performance, and thus do not satisfy the selection criteria (specifically, criterion

[150] For example, this plant's data are well within the range of the Interquartile Range Rule. See Section 8 of the Supplemental TDD for more discussion.

5) above.[151] Remaining comments suggesting inclusion of individual data points were reasonable and adhered to sound engineering principles. Since EPA agrees with commenters that these are valid, representative data, EPA included them in the final limitations calculations.

The Agency agrees with commenters that full-scale system data is typically preferable to pilot study data. Nevertheless, EPA weighed the potential benefit of waiting for full-scale LRTR system data (which due to the recency of LRTR installations is only just being collected) versus the potential harm of delaying a final rule where the 2015 rule compliance dates are this year, and determined such a course of action is not warranted. The Agency has always maintained, and courts have upheld, its ability to establish limitations based on pilot data. *See Am. Iron & Steel Institute* v. *EPA,* 526 F.2d 1027, 1063 (3d Cir. 1975); *Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1054 n.70 (D.C. Cir. 1978). Furthermore, the Agency does not need to wait for better information when the information available is sufficient. *See Texas Oil and gas Ass'n* v. *EPA,* 161 F.3d 923, 935 (5th Cir. 1998) (''An agency's choice to proceed on the basis of 'imperfect information' is not arbitrary and capricious unless 'there is simply no rational relationship' between the means used to account for any imperfections and the situations to which those means are applied.'') (citation omitted). Here the Agency determined that the pilot data are sufficiently representative, and therefore the marginal adjustments in limitations that might result from full-scale system performance data do not warrant the delayed pollutant reductions of these limitations going into effect.

EPA also disagrees that nitrate/nitrite limitations are unnecessary. While commenters are correct that a properly operated and maintained biological treatment system will necessarily remove nitrate/nitrite prior to reduction of selenium, it is the nitrate/nitrite limitations themselves that in part ensure that the BAT technology or other comparable technology is used. In the absence of a nitrate/nitrite limit, two electric utilities described how the use of chemical precipitation-based systems might be used to treat selenium in the selenite form if the limitation is raised from the 2015 rule limit.[152] Another pilot of a ZVI system showed high selenium removal efficiency but did not consistently remove nitrogen (DCN SE05619). Neither the chemical-precipitation-based systems or ZVI systems would consistently treat nitrate/nitrite and thus, while they may be a more advanced technology than chemical precipitation alone and meet the limitations for mercury, arsenic, and selenium included in this final rule, neither would achieve full compliance.

Finally, EPA received an additional LRTR pilot data set conducted at the Kingston power plant. EPA had mentioned this pilot at proposal, but the full study and analysis of data were only completed in January 2020. While commenters did not have an ability to comment on the data per se, EPA continues to rely on the same criteria for selecting and including representative data, and the same methodology for analyzing those data in development of the long-term averages and limitations, and other data, all of which were subject to public comment. The data meet the criteria specified above, and EPA has determined these are valid, representative data. Therefore, EPA has supplemented the LRTR data used for development of the final limitations with the Kingston data set. *See BASF Wyandotte Corp.* v. *Costle,* 598 F.2d 637, 644–46 (1st Cir. 1979) (holding that EPA's use of new data in a final rule did not deprive the public of a fair opportunity to comment on the data). The outcome of the changes described above was generally to lower long-term averages but increase daily variability factors. This results in, for example, higher daily arsenic limitations while monthly arsenic limitations were lower.

EPA also received comments on the VIP limitations. As with the CP+LRTR limitations comments, commenters argued that EPA should not have excluded certain data points, and that such exclusions had made the limitations too stringent. Commenters also argued that EPA had relied too heavily on non-detects.

Commenters suggested that EPA include certain individual data points because the data were reasonable and adhered to sound engineering principles. EPA agrees with commenters that these are valid, representative data. EPA has included these data in the final VIP limitations calculations. The situation with non-detect data was more complicated. The same commenters who suggested that the monthly data sets relied too heavily on non-detect data also made very compelling arguments that EPA should have evaluated membrane filtration with pretreatment using chemical precipitation, as discussed with respect to updated costs in Section VIII above. In light of these compelling comments, and for consistency, EPA re-evaluated the data used to develop the proposed VIP limitations. The record indicates that one pilot plant incorporated microfiltration rather than chemical precipitation for a portion of its pilot data set, and therefore EPA decided that the microfiltration-only subset of data should be excluded as it is not representative of the BAT technology basis for the final rule (see Section VII(B)(1) above). As a result, EPA agrees that some of the monthly data sets relied heavily on non-detect data, and due to the inability to calculate monthly variability factors with the reduced data set, has not finalized a monthly limitation for selenium or bromide.[153] This also resulted in daily limitations for selenium and bromide that are just one-half and one-third of those proposed, respectively. In contrast, EPA found that monthly limitations for mercury, nitrate/nitrite, and TDS were still appropriately calculated from detected concentrations. Importantly, the Agency has not eliminated the daily maximum limitations for these constituents, and it finds that the very low monthly average TDS limitations ensure that VIP systems are obtaining sufficient pollutant removals at plants that do not eliminate their discharges completely (*e.g.,* by recycling permeate or distillate).

Table XIV–1 presents the final 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 plant 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, EPA recommends that plants design and operate their treatment system to achieve the long-term average for the model technology. A system that is designed and operated to achieve the long-term average BAT/PSES level of control would meet the limitations.

EPA expects that plants will be able to meet their effluent limitations or

[151] However, to the extent such artificial conditions could be representative of an upset, the Agency still finds that these data may be useful for plants to consider when designing their systems.

[152] TVA suggested that a sulfide analyzer would allow it to monitor ORP in the FGD to produce a higher fraction of selenite (a form of dissolved selenium which, with optimization, can be precipitated to a high degree, even without a biological treatment stage).

[153] Monthly average limits for arsenic were not calculated for the proposal, and thus this is not a change.

standards at all times. If an exceedance is caused by an upset condition, the plant 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 plant's performance does not represent the appropriate level of control. For the final limitations and pretreatment standards, EPA finds that such exceedances can be controlled by diligent operational practices for the process and wastewater treatment system, 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 plants 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 EPA's costing approach and its engineering judgment, developed over years of evaluating wastewater treatment processes for steam electric power plants and other industrial sectors. EPA recognizes that some dischargers, including those that are currently operating technologies representing the technology basis for the final rule and VIP, may need to improve their treatment systems, process controls, and/or treatment system operations in order to consistently meet the final effluent limitations and pretreatment standards. This is consistent with the CWA, which requires that BAT/PSES discharge limitations and standards reflect the best available technology economically achievable.

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 plants not in the VIP or subcategories specified below (BAT & PSES).	Arsenic (µg/L	4.98	18	8
	Mercury (ng/L)	13.48	103	34
	Nitrate/nitrite as N (mg/L).	2.14	4	3
	Selenium (µg/L)	15.87	70	29
Voluntary Incentives Program for FGD Wastewater (existing direct dischargers).	Arsenic (µg/L)	[b] 5.0	5	NA
	Mercury (ng/L)	5.44	23	10
	Nitrate/nitrite as N (mg/L).	0.89	2.0	1.2
	Selenium (µg/L)	7.35	10	NA
	Bromide (mg/L)	0.200	0.2	NA
	TDS (mg/L)	86.06	306	149
Low utilization subcategory-AND-High FGD flow subcategory (BAT & PSES).	Arsenic (µg/L)	5.98	11	8
	Mercury (ng/L)	159	788	356

[a] BAT effluent limitations for EGUs that will permanently cease the combustion of coal 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 EGUs are: Daily maximum of 100 mg/L; and monthly average of 30 mg/L.

[b] Long-term average is the arithmetic mean of the quantitation limitations because 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.

EPA notes that some limitations are higher than corresponding limitations in the 2015 rule (or even the 2019 proposal), and in other cases limitations of additional pollutants or lower limitations for pollutants regulated in the 2015 rule have also been calculated.

B. BA Transport Water Limitations

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

In contrast to the concentration-based, numeric limitations estimated for specific pollutants above, EPA is finalizing a pollutant discharge allowance in the form of a site-specific percentage purge rate for BA transport water with a maximum cap. To develop this requirement, EPA first collected data on the discharge needs of the model treatment technology (high recycle rate systems) to maintain water chemistry or water balance.[154] EPRI (2016) presents discharge data from seven currently operating wet BA transport water systems at six plants. These plants 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. EPA's goal in establishing the purge rate was to provide a requirement based on process needs, as reflected in the EPRI (2016) data, as well as infrequent precipitation and maintenance events. While EPRI (2016) noted that infrequent discharges happened at some plants, 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 frequencies of such infrequent events for currently operating wet BA systems.[155] For purposes of calculating the maximum allowance percentage associated with such infrequent events, EPA divided the discharge associated with an estimated maintenance and precipitation event by the volume of the system, and then

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

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

averaged the resulting percent over 30 days.

Finally, EPA added each reported regular discharge percent from EPRI (2016) to the averaged infrequent discharge percent under four scenarios: (1) With no infrequent discharge event; (2) with only a precipitation-related discharge event; (3) with only a maintenance-related discharge event; and (4) with both a precipitation-related and maintenance-related discharge event. These potential discharge needs are reported in Table XIV–2 below. Consistent with the statistical approach used to develop effluent limitations and pretreatment standards for individual pollutants, EPA selected a 95th percentile of total system volume as representative of a 30-day rolling average, which results in a limitation of 10 percent of total system volume.[156]

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	Plant A	Plant B	Plant C	Plant D	Plant E	Plant F-system 1	Plant F-system 2
		0.1%	0.0%	1.0%	0.0%	0.8%	2.0%	2.0%
Neither Event	0.0%	0.1%	0.0%	1.0%	0.0%	0.8%	2.0%	2.0%
Precipitation Only	5.4%	5.5%	5.4%	6.4%	5.4%	6.2%	7.4%	7.4%
Maintenance Only	3.3%	3.4%	3.3%	4.3%	3.3%	4.1%	5.3%	5.3%
Both Events	8.7%	8.8%	8.7%	9.7%	8.7%	9.5%	10.7%	10.7%

[a] These estimates sum actual, reported, plant-specific regular discharge needs with varying combinations of hypothetically estimated, infrequent discharge needs.

EPA received a significant range of comments on the calculation of this 10 percent purge. Many comments concerned the treatment of infrequent purges, especially those relating to precipitation. The range of comments demonstrates, among other things, that a nationwide limitation for precipitation-related purges can be too stringent in some geographic areas and not stringent enough in others. EPA, therefore, made modifications in the final rule that require the NPDES permitting authority to develop a site-specific purge percentage that is capped at 10 percent.[157] EPA recognizes that some plants may need to improve their equipment, process controls, and/or operations to consistently meet the limitations included in this final rule; however, this is consistent with the CWA, which requires that BAT/PSES discharge limitations and standards reflect the best available technology economically achievable.

The remainder of comments on the 10 percent purge calculation recommended additional circumstances in which EPA should allow a purge beyond 10 percent. EPA disagrees with these comments because the 10 percent purge cap that EPA estimated is reflective of properly operated and maintained high recycle rate systems, the technology that EPA selected as BAT. In the rare cases when precipitation-related events result in a purge of greater than 10 percent—100-year/24 hour storms, multiple large storms, etc.—EPA notes that the NPDES regulations contain flexibilities for upset and bypass. See 40 CFR 122.41(m) and (n).

2. Best Management Practices Plan

As described in Section VII of this preamble, the final rule requires a subcategory of plants discharging BA transport water and having a low CUR 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 final BMP provisions require subject plants to develop a plan to minimize the discharge of pollutants by recycling as much BA transport water as feasible back to the BA handling system.[158] After determining the amount of BA transport water that could be feasibly recycled and developing and implementing a plant-specific BMP plan, plants are required to review the plan annually and revise it as necessary.

XIV. Regulatory Implementation

A. Implementation of the Limitations and Standards

The limitations and standards in this rule apply to discharges from steam electric power plants through incorporation into NPDES permits issued by EPA or by authorized states under Section 402 of the CWA, and through local pretreatment programs under Section 307 of the CWA. NPDES permits or control mechanisms issued after this rule's effective date must incorporate the ELGs, as applicable. Where permits with the 2015 rule limitations have already been issued, EPA expects that the final rule requirements will be incorporated through permit modifications in most cases. 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 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 in this rule 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 final rule provides the plant's permitting authority with certain discretion to determine the date when the new effluent limitations for FGD wastewater and BA transport water will apply to a given discharger. The rule specifies that the earliest date these new limitations can apply to a discharger is

[156] While there were further decimal points for the actual calculated 95th percentile, 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.

[157] As discussed in Section VIII(b)(2) above, to the extent that a precipitation event such as a hurricane were to occur and result in a plant needing to discharge in excess of the established purge percent, upset provisions provide a potentially appropriate affirmative defense.

[158] Since the BMP plan requirements include periodic updates, a change in treatment technology (for instance due to the CCR rule) would be reflected automatically in the BMP plan.

October 13, 2021. Except for the limitations in certain subcategories, for any final effluent limitation that is specified to become applicable after October 13, 2021, the specified date must be as soon as possible after that date, but in no case later than December 31, 2025. Consistent with the proposal, for dischargers choosing to meet the VIP effluent limitations for FGD wastewater, the date for meeting those limitations is December 31, 2028.

For FGD wastewater and BA transport water from EGUs permanently ceasing the combustion of coal by 2028, the final BAT limitations for this subcategory apply on the date that an NPDES permit is issued to a discharger. The final 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.

Consistent with the proposal, for FGD wastewater and BA transport water from low utilization EGUs and FGD wastewater from high FGD flow plants, the final BAT limitations for these subcategories would apply on or after October 13, 2021. The specified date must be as soon as possible after that date, but in no case later than December 31, 2023. EPA considered earlier and later dates than December 31, 2023. With respect to later dates, the limitations in these subcategories are less stringent than the limitations in the 2015 rule, which the Agency found were achievable by 2023. Nothing in the Agency's record since then would suggest otherwise. Thus, the Agency did not select a later date. With respect to earlier dates, EPA acknowledges that some of the limitations might be implemented sooner at some plants. Nevertheless, the Agency is retaining the December 31, 2023 date. For LUEGUs, the Agency is allowing demonstration of the required CUR by December 31, 2023, in response to comments, as discussed in Section XIV(A)(3) below. Since it would be inconsistent to require compliance with these limitations prior to demonstration that the LUEGU CUR requirements are met, setting a ''no later than date'' earlier than December 31, 2023, would not adequately support this modified requirement of the final rule. For high FGD flow plants, EPA is also retaining the outside compliance date of December 31, 2023. In an FDF variance request filed for the single known high flow plant, that plant indicated that it did not have chemical precipitation, and preliminary estimates were that chemical precipitation would take until 2023 to construct, commission, and optimize. The EPA does not have any information to suggest that a chemical precipitation system at a high flow plant could be installed any more quickly; however, to the extent that an earlier date is feasible at a high FGD flow plant, the permitting authority can already account for this under current 40 CFR 423.11(t).

Pretreatment standards, unlike effluent limitations, are directly enforceable and must be met three years after the effective date of any final rule. CWA section 307(b)(1). Under EPA's General Pretreatment Regulations for Existing and New Sources, POTWs with flows in excess of 5 Mgd must develop pretreatment programs meeting prescribed conditions, including the legal authority to require compliance with applicable general and categorical pretreatment standards and control the introduction of pollutants to the POTW through permits, orders or similar means, to ensure the contribution to the POTW by each industrial user is in compliance with applicable pretreatment standards and requirements. POTWs with approved pretreatment programs act as the control authorities for their industrial users. Among the responsibilities of the control authority are the development of the specific discharge limitations for the POTW's industrial users. Because pollutant discharge limitations in categorical pretreatment standards may be expressed either as concentrations or mass limitations, the control authority, in many cases, must convert the pretreatment standards to limitations applicable to a specific industrial user and then include these in POTW permits or another control instrument.

Regardless of when a plant's NPDES permit is ready for renewal, EPA recommends that each plant immediately begin evaluating how it intends to comply with the requirements of any final rule. In cases where significant changes in operation are appropriate, EPA recommends that the plant 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 plant's final NPDES permit was issued before these ELGs were finalized and includes limitations for BA transport water and/or FGD wastewater from the 2015 rule, the permitting authority may modify the permit based on promulgation of this rule pursuant to 40 CFR 122.62(a)(3). EPA recommends that the plant and permitting authority determine whether such a permit should be modified in light of this rule, and if so, that it be modified as soon as practicable and consistent with any new rule provisions.[159]

The ''as soon as possible'' date is October 13, 2021, unless the NPDES permitting authority determines another date after receiving relevant information submitted by the discharger.[160] The final rule does not revise the specified factors that the NPDES permitting authority must consider in determining the as soon as possible date under the 2015 rule. Assuming that the NPDES permitting authority receives relevant information 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.[161]

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

EPA proposed to clarify that the discharger must provide relevant, site-specific information for consideration of these factors by the permitting authority. However, commenters stated that in many cases, information developed to inform these decisions may reflect fleet-wide or company-wide operations, maintenance or financial information and may not be ''site-specific'' to a single plant or EGU. Thus, the key is that the information be demonstrated to be relevant to the plant in question, but need not be based on

[159] In some circumstances, if a permit cross-references or incorporates the regulation by reference, if state law allows, it is possible that the changes finalized today might be automatically incorporated. However, this is unlikely to be the case in many permits, and plants should carefully review their permits before drawing this conclusion.

[160] 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.

[161] Cooperatives and municipalities presented information to EPA suggesting that obtaining financing for these projects can be more challenging than for investor-owned utilities. Under this factor, permitting authorities may consider whether the type and size of owner and difficulty in obtaining the expected financing might warrant additional flexibility up to the ''no later than'' date.

site-specific operations, maintenance or financial information. The Agency agrees with these comments, and thus the final rule does not include a requirement for unique, site-specific information.

As specified in factor (b), the permitting authority must also consider scheduling for installation of equipment, which includes a consideration of plant changes planned or being made to comply with certain other key rules that affect the steam electric power generating 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 plant 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 NPDES 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 October 13, 2021, the justification would explain why allowing additional time to meet the final limitations is appropriate, and why the discharger cannot meet the effluent limitations as of October 13, 2021. In cases where the plant is already operating the BAT technology basis for a specific wastestream (*e.g.,* high recycle rate system for BA transport water), 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 October 13, 2021 (for example due to the CCR rule), it would not usually be appropriate to allow additional time beyond that date to comply with the final rule limitations and standards. Regardless, in all cases, the permitting authority would make clear in the permit by what date the plant must meet the final limitations, and that date is no later than December 31, 2025.[162]

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

2. Determining the Site-Specific Bottom Ash Purge Water Volume and Treatment

While EPA is establishing a maximum 10 percent volumetric cap on bottom ash purge water, the NPDES permitting authority is to determine the site-specific volumes and technology-based BAT effluent limitations using BPJ.[163] To assist the NPDES permitting authority in making these determinations, EPA is requiring information on the types of discharges and available treatment technologies in the reporting and recordkeeping requirements discussed below. However, having reviewed the information available in the record, EPA has distilled certain basic principles that may be useful for a permitting authority to consider.

Information in EPA's record indicates that purges can be classified into two distinct classes. The first class comprises purges that must be made on a regular or continuous basis. These purges are typically related to system water chemistry or water balance and are permissible under 40 CFR 423.13(k)(2)(i)(A)(*2*) and (*3*). Based on EPA's record, once a plant has taken steps to manage such purges, these purges should typically comprise a small portion of system volume, and in some cases may have volumes close to zero. The second class of purges are those that are made less frequently. Based on information in EPA's record, discharges from storm events larger than a 10-year, 24-hour or longer duration event, or maintenance events not included in 40 CFR 423.13(k)(2)(i)(A)(*1*) through (A)(*3*)—such as those associated with EGU outages or decommissioning of the high recycle rate system—are expected in many cases to occur at most once per year and are permissible under 40 CFR 423.13(k)(2)(i)(A)(*1*) and (*4*).

EPA notes that the storm events included in (A)(*1*) are: Different from those included at proposal in two ways. First, commenters suggested that EPA use a 10-year storm event rather than a 25-year storm event. EPA agrees that such a change makes the requirements consistent with those for coal pile runoff.[164] Second, commenters pointed to a 30-day rainfall event in Tennessee in which individual 24-hour precipitation events may not have exceeded a 10-year storm event, but multiple 24-hour periods of precipitation taken together did exceed a 10-year, 30-day storm event. At proposal EPA had used the phrase ''multiple consecutive events'' to capture such a possibility; however, the more precise characterization of the event in the Tennessee example would be a 10-year, 30-day storm event. Therefore, the Agency now uses the phrase ''or longer duration'' to denote all 10-year events of a duration longer than 24-hours.[165]

Permitting authorities may initially determine which of these two classes of purge are necessary at any given site. Where necessary purges fall into the first class, and result in relatively consistent volumes and water quality, such a discharge may be more amenable to treatment technologies beyond physical settling. Necessary purges fall into the second class, and result in infrequent and potentially very large volumes; such a discharge may make treatment beyond physical settling challenging. In both of these cases, where only a single class of purge is expected, the permitting authority's job will be more straightforward.

A more challenging scenario occurs when the NPDES permitting authority determines that both classes of purge will be present. In such cases a permitting authority could consider whether tiered or differentiated purges or purge treatment might be warranted. For example, during periods where no large precipitation or maintenance events occur, continuous purges may be properly limited to a smaller volume, with more advanced treatment with a second limitation permitting larger volumes and less advanced treatment during periods where the plant records a qualifying event. There is no across-the-board formula for determining appropriate purge limitations, as long as the bottom ash purge volume does not exceed 10 percent of the primary active wetted bottom ash system volume on a 30-day rolling average basis.

[162] For BA purge water, permitting authorities may determine the appropriate timeframe for any limitations imposed as a result of a BPJ analysis on this wastestream; however, EPA strongly encourages state and tribal permitting authorities to invest the time and resources necessary to establish BPJ limits for BA purge water and issue permits timely to allow facilities to install the necessary equipment within the compliance deadlines in the final rule.

[163] BPJ limits established by the permitting authority only apply to discharges from high recycle rare systems and do not apply to BA transport water discharges from LUEGUs or EGUs permanently ceasing coal combustion, as plants eligible for those subcategories are subject to the TSS limitations established in this final rule.

[164] 40 CFR 423.12(b)(10).

[165] *NOAA ATLAS 14 POINT PRECIPITATION FREQUENCY ESTIMATES* include the following 10-year events in this range: 24-hour, 2-day, 3-day, 4-day, 7-day, 10-day, 20-day, 30-day, 45-day, and 60-day storm events. Available online at: *https://hdsc.nws.noaa.gov/hdsc/pfds/pfds_map_cont.html* (DCN SE09100).

3. Implementation for the Low Utilization Subcategory

The final rule establishes a subcategory for LUEGUs with a two-year average capacity utilization rate (CUR) of less than 10 percent per year. CUR is calculated as the total MWh of production divided by the hours per year times the nameplate capacity. Unlike other subcategories, which often require that a plant possess some static characteristic (*e.g.,* less than 50 MW nameplate capacity), the low utilization subcategory is based on the fluctuating CUR. Thus, EPA is clarifying how permitting authorities can determine whether a plant qualifies for this subcategory.

If a plant seeks to have the limitations from this subcategory applied to discharges from one or more EGUs, the plant needs to provide the permitting authority its calculation of the average of the most recent two calendar years of CUR for the subject EGU(s). EPA received some comments that plants should be allowed to certify to future low utilization operations, even where current operations are not low utilization. Other comments stated that additional reporting and recordkeeping should be required to prevent abuse. EPA agrees with both comments. It was not the Agency's intent for plants on a downward utilization trajectory to be barred from the LUEGU subcategory, where current operations exceed the required less than 10 percent CUR threshold. Thus, the NPDES permitting authority should refrain from establishing a ''no later than date'' that would restrict a plant from demonstrating two years of reduced CUR. However, NPDES permitting authorities also need to know when to provide flexibility and when to dutifully set a compliance date which is ''as soon as possible.'' Thus, EPA is requiring in the rule that a plant seeking to qualify for this subcategory must file a Notice of Planned Participation (NOPP) by October 13, 2021, even if it would not yet qualify, and must operate below this threshold before the latest compliance dates of December 31, 2023. Upon receipt of a NOPP, the NPDES permitting authority can properly consider that NOPP in the ''other factors'' of 40 CFR 423.11(t)(4).

Once a plant reaches the ''as soon as possible'' date determined by the permitting authority, it must thereafter provide annual certifications of its 24-month average CUR. This average should primarily be calculated using data developed for reporting to the EIA, since MWh production information already collected for the EIA will both eliminate the potentially unnecessary paperwork burden of a separate calculations and information gathering and allow the NPDES permitting authority to verify the accuracy of the reported values more easily. The use of a two-year average will ensure that a low utilization EGU 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 CUR over the two years remains below 10 percent. Furthermore, the plant must annually provide the permitting authority an updated two-year average CUR for each subcategorized EGU within 60 days of submitting production information to the EIA to ensure that it remains an LUEGUs.

4. Transitioning Between Limitations

EPA received a significant number of comments that it should harmonize the CCR and ELG rules to the extent practicable. As discussed above, EPA agrees that such harmonization is important. One major set of features EPA attempted to harmonize this final rule with are the alternative closure provisions of Paragraphs 257.103(f)(1) and (f)(2) of the CCR rule. In response to comments on the CCR Part A Proposed Rule (one of which, the USWAG comment, was incorporated by reference into a public comment submitted for this ELG rule), EPA added a provision to the final CCR Part A Rule that provides for transfer between these paragraphs. A plant that had applied for a site-specific alternative closure extension to extend its cease receipt of waste date under paragraph 257.103(f)(1) could, for example, now transfer into the provision that requires permanent cessation of a coal-fired EGU under paragraph 257.103(f)(2). Similarly, EPA has discussed transfer between ELG subcategories with electric utilities. Thus, to align with the flexibilities of the CCR Part A final rule and make implementation of this rule easier, EPA is finalizing provisions allowing for a plant with a permit to transfer between two subcategories, or between a subcategory and the VIP, without undergoing a permit modification.[166]

The EPA is also establishing deadlines by which such transfers must occur. Transfers into the LUEGU subcategory must occur no later than December 31, 2023, the latest date by which compliance dates for this subcategory would fall. For all other transfers, the EPA is selecting December 31, 2025 as the latest date for three reasons. First, the ability to transfer under Section 257.103 of the CCR Rule will terminate before this date, giving plants certainty as to their CCR compliance strategies. Thus, it is consistent with the CCR rule. Second, the first five-year permitting cycle will have ended, and EPA expects that plants subject to NPDES permitting under this rule will have determined their compliance path by then. Lastly, some of the provisions that can be transferred to in this rule include compliance dates for the generally applicable limitations of no later than December 31, 2025. In such cases, allowing transfer to such provisions at a later date could create disparities for compliance with these genearlly applicable limitations within the industry. Thus, a final transfer date of December 31, 2025, creates a consistent time frame for all plants to make decisions and achieve compliance with the generally applicable limitations, whether they initially start in another subcategory or not.

Consistent with the CCR Part A final rule requirements, a plant seeking to transfer between the ELG rule provisions must demonstrate compliance with all requirements of both the provision transferred from and the provision transferred to, and continue to meet requirements that were applicable if that applicability date has passed. This ensures that a plant does not miss or circumvent otherwise applicable deadlines or cease operating equipment already installed, operated, and maintained to comply with deadlines that have passed.

The first objective addresses, for example, a plant converting from the permanent cessation of coal combustion subcategory with deadlines of 2028, to the LUEGU subcategory, with deadlines no later than 2023. EPA does not want a plant to miss or circumvent the lastest LUEGU compliance dates of December 31, 2023, because the plant initially

[166] Categorical pretreatment standards are directly enforceable and are not implemented through NPDES permits issued to indirect dischargers. Indirect dischargers, however, may be subject to enforceable individual local permits or equivalent individual control mechanisms issued to individual indirect dischargers by a POTW with an approved pretreatment program or the appropriate control authority. Because indirect dischargers do not have NPDES permits, the NPDES provisions for transferring between limits in a permit do not apply to indirect dischargers. Indirect dischargers subject to categorical pretreatment standards under EPA's pretreatment regulations must comply with these standards. What pretreatment standards will apply depends on whether an indirect discharger is subject to a particular subcategory as provided in the regulation. As such, in the event the pretreatment standards change, the indirect dischargers will be subject to the modified standards.

intends to meet the 2028 requirements and later changes its mind. Such a scenario could, for example, result in the plant failing to meet the 2023 LUEGU requirements for five years between 2023 and 2028.

The second objective would mean that, for example, where a plant is already implementing a BMP plan for BA transport water under the LUEGU subcategory and then decided to convert to the subcategory for permanent cessation of coal combustion, the plant would continue to implement the BMP plan until such cessation occurs. This ensures that technology-based requirements that were applicable would continue to be met, furthering the goals of eliminating discharges to the extent technologically available and achievable under section 301(b) of the CWA.

This new set of provisions is also appropriate as a practical matter to implement the subcategories as finalized. While EPA proposed for plants to certify to a subcategory immediately, based on public comments. EPA has finalized provisions allowing plants to file an initial notice of planned participation such that the plant could certify differently within the compliance time frame. In many cases, a plant may require local or state regulatory approval prior to reducing its utilization or planning to retire. These changes in the final rule allow plants to notify their permitting authority of their intent to particpiate in a subcategory, but also allows time to obtain local or state approval, if necessary, before the compliance deadline. By allowing automatic transfer between alternatives, the final rule also avoids unecessarily burdensome permit modifications that can further extend timelines to make plant changes, including equipment upgrades.

Finally, the Agency notes that with later dates for certification and the ability to transfer between alternative limitations for a period of time, there is no longer a need for tiered limitations in the LUEGU subcategory. Thus, the proposed tiering of limitations are not being finalized.

5. Addressing Unexpected Changes in Generation

Since the 2015 rule, EPA has learned of several instances when plants have withdrawn or delayed retirement announcements for coal-fired EGUs and plants. 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, EPA acknowledges that such changes will necessarily impact a plant's status with regard to some of the subcategories in the final rule. These situations are discussed below. For further information on announced retirements, *see* DCN SE07207.

a. Involuntary Retirement Delays

At least five plants 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.[167] Today's final rule would subcategorize LUEGUs and EGUs permanently ceasing coal combustion by 2028, subjecting those subcategories to less stringent limitations. However, both utilization and decisions to permanently cease coal combustion could be impacted by involuntary orders and agreements. Thus, EPA is establishing in this final rule an NPDES permit condition that would be included in all permits where a plant seeks limitations under one of these two subcategories. Such a provision protects a plant that involuntarily fails to qualify for the subcategory for low utilization EGUs or EGUs permanently ceasing coal combustion by 2028, and it allows that plant to prove that, but for the order or agreement, it would have qualified for the subcategory. EPA received comments that the enumerated orders in the proposal were too narrow, and that alternative regulatory bodies (*e.g.,* Independent System Operators) might also issue these types of orders. EPA agrees with these commenters, and thus, has modified the language in section 423.18(a) of the final rule.

b. Emergencies and Major Disasters Under the Stafford Act

The final rule also includes in the section 423.18(a) provision ''Emergency'' [168] and ''Major Disaster'' [169] events as defined by the Stafford Act.[170] These events encompass scenarios such as the current Covid–19 pandemic, floods, hurricanes, and other scenarios that may not be predictable, but may impact the need for, and availability of, electricity. The benefit of adding these terms to the emergency orders and must run agreements already detailed in section 423.18(a) is that it would prevent an EGU from being noncompliant if operations during such an emergency or major disaster would have otherwise caused it to exceed the rule's capacity utilization threshold. Stafford Act declarations of major disaster or emergency are made by the President at the request of the Governor or Chief Executive of an Indian Tribe. *See* 42 U.S.C. 5170 and 5191. For emergency declarations involving primary federal responsibility, the President does not need a request from the Governor, but may make an emergency determination (42 U.S.C. 5191(b)). Furthermore, these events are limited in geographic scope and in duration. Thus, while they would advance the protection for future LUEGUs to operate in emergency situations above the required capacity, they would be relatively rare, thus maintaining the majority of pollutant removals expected under this final rule in the long run.

c. Voluntary Retirement Withdrawals and Delays

Units at five plants 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 plant. Like the involuntary retirement delays discussed in the section above, these situations could impact a plant's qualification for the subcategories for LUEGUs and EGUs ceasing combustion of coal by 2028. Unlike the involuntary retirement delays, these voluntary delays and withdrawals can be accounted for through normal integrated resource planning. Thus, the final rule does not include a similar protection provision for such units. Instead, a plant should carefully plan its implementation of the ELGs.

B. Reporting and Recordkeeping Requirements

To implement the rule's provisions providing for subcategories and a site-specific determination of controls on BA purge water, this final rule includes eight reporting and recordkeeping requirements. There were two

[167] 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.* (DCN SE09101)

[168] 42 U.S.C. 5122(1).

[169] 42 U.S.C. 5122(2).

[170] 42 U.S.C. 5121 *et seq.*

overarching goals of these requirements. The first goal was to balance the additional flexibilities for certifying to subcategories or VIP limitations at a later date with additional reporting and recordkeeping to provide extra certainty that the plant still intends to avail itself of those provisions. A second goal was to adopt provisions consistent with those of the CCR rule where an initial notice is provided to EPA, followed by regular progress reports to avoid last-minute surprises that might result in unexpected noncompliance.[171]

First, EPA is finalizing a reporting and recordkeeping requirement for plants operating high recycle rate BA systems. EPA is requiring that such plants submit the calculation of the primary active wetted BA system volume, which means the maximum volumetric capacity of bottom ash transport water in all non-redundant piping (including recirculation piping) and primary tanks (*e.g.,* bins, troughs, clarifiers, and hoppers) of a wet bottom ash system, excluding the volumes of surface impoundments, secondary bottom ash system equipment (*e.g.,* installed spares, redundancies, and maintenance tanks), 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.

Because the NPDES permitting authority is basing the site-specific purge percentage and limitations on BPJ, EPA is also requiring the following:

(1) A list of all potential discharges, the expected volume of each discharge, and the expected frequency of each discharge.

(2) Material assumptions, information, and calculations used by the certifying professional engineer to determine the expected volume and frequency of each discharge.

(3) A list of all wastewater treatment systems currently at the plant, or otherwise required by a date certain under this section.

(4) A narrative discussion of each treatment system, including the system type, design capacity, and current operation.

Second, EPA is finalizing a reporting and recordkeeping requirement for plants seeking to qualify as an LUEGU. EPA is requiring that the plant submit a NOPP to certify one or more LUEGUs. Once any limitations of this subcategory are applicable, the final rule requires that such a plant annually recertify that the EGU continues to meet the requirements of this subcategory, along with an updated two-year average CUR calculation and information for each applicable EGU. If an EGU exceeds the CUR requirements of this subcategory, no further recordkeeping or reporting would be required for this subcategory, as the EGU would leave the subcategory permanently.

Third, as described in Section VII.C.2, plants with EGUs that qualify for the low-utilization subcategory and that discharge BA transport water, are required to develop and implement a BMP plan to minimize the discharge of pollutants by recycling as much BA transport water as feasible back to the BA handling system.[172] As part of any NPDES permit renewal or any re-opening, such plants need to submit their plant-specific plan, certified that it meets the proposed requirements of 40 CFR 423.13(k)(3)) along with certification that the plan is being implemented. For each NPDES permit renewal, the plan and professional engineer certification needs to be updated and provided to the permitting authority.

Fourth, EPA is finalizing reporting and recordkeeping requirements for plants seeking subcategorization for an EGU(s) achieving permanent cessation of coal combustion by December 31, 2028. EPA is requiring that a plant file a NOPP to certify one or more such EGUs, including whether the retirement or fuel conversion has already been approved by the regulatory authority. EPA received comments suggesting that additional information should be required regularly from such EGUs. EPA agrees that, given the time frame for retiring or repowering some EGUs, a lack of reporting combined with missed deadlines could lead to situations where a plant fails to permanently cease coal combustion as scheduled and immediately falls into noncompliance without the permitting authority being aware of the situation. Thus, EPA is also requiring in the rule annual progress reports to confirm that the EGU is on track to complete its retirement or fuel conversion on time. This requirement is meant to provide the NPDES permitting authority further evidence that an EGU will, in fact, cease the combustion of coal by December 31, 2028.

Fifth, EPA is finalizing reporting and recordkeeping requirements for plants invoking the protective NPDES permit conditions described above, which allow a plant to continue to be subject to limitations for low utilization EGUs or those ceasing combustion of coal by 2028 in the event of an emergency order, must-run agreement, national emergency, or major disaster. EPA is requiring in the rule that such plants must demonstrate that an EGU would have qualified for the subcategory at issue, if not for the emergency order, must-run agreement, national emergency, or major disaster as described above. Furthermore, EPA is requiring in the rule that the plant submit to the NPDES permitting authority a copy of such order or agreement as an attachment to the submission.

Sixth, EPA is finalizing reporting and recordkeeping requirements for plants participating in the VIP. As with the retirement subcategory, given the long time frames, a lack of reporting combined with missed deadlines could lead to situations in which a plant fails to complete the installation of a VIP technology as scheduled and immediately falls into noncompliance without the permitting authority being aware. Thus, EPA is requiring in the rule annual progress reports to confirm that the plant is on track to complete its VIP technology installation. This requirement is meant to provide the NPDES permitting authority further evidence that an EGU will, in fact, be able to meet the VIP limitations by December 31, 2028.

Seventh, the final rule includes reporting and recordkeeping requirements for plants transitioning between compliance alternatives. For example, a plant may initially file a NOPP for participation in the permanent cessation of coal combustion subcategory, but then several years later it may determine that it is profitable to remain in operation, and instead comply with the VIP. Under such scenarios, where the permitting authority has included alternative limitations subject to eligibility requirements, EPA is requiring in the rule that the plant provide a notice to the NPDES permitting authority of what transition the plant will make.

[171] While the initial notice in the CCR rule is termed a ''notice of intent'' because that is a CWA term of art related to NPDES permitting that has a different meaning than intended here, this final rule provides a ''notice of planned participation.'' The intended result is the same for both rules, to give the permitting authority advanced notice that a plant intends to avail itself of provisions other than those generally applicable to the industry.

[172] EPA is finalizing the same requirements for determining feasibility that were included in the proposal: Segregation of bottom ash transport water from other process water, minimization of the introduction of stormwater by diverting (*e.g.,* curbing, using covers) stormwater to a segregated collection system, recycling bottom ash transport water back to the bottom ash transport water system, recycling bottom ash transport water for use in the FGD scrubber, optimization of existing equipment (*e.g.,* pumps, pipes, tanks) and installing new equipment where practicable to achieve the maximum amount of recycle, and utilization of ''in-line'' treatment of transport water (*e.g.,* pH control, fines removal) where needed to facilitate recycle.

Finally, the final rule includes a requirement that a plant provide notice of any material delays, meaning a delay that could result in non-compliance (with the compliance date set forth in the permit) within 30 days of experiencing such a delay.[173] For instance, if such a delay might preclude permanent cessation of coal combustion by December 31, 2028, a plant shall file a notice of material delay with the permitting authority (or the control authority in the case of an indirect discharger) to facilitate resolution before the compliance date. The notice requirement does not change the 2028 date in this rule but provides the permitting authority adequate notice to seek a resolution. The contents of such a notice shall include the reason for the delay, the projected length of the delay, and a proposed resolution to maintain compliance.

C. Site-Specific Water Quality-Based Effluent Limitations

EPA regulations at 40 CFR 122.44(d)(1), implementing section 301(b)(1)(C) of the CWA, 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. 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. EPA stated its recommendation that permitting authorities carefully consider whether water quality-based effluent limitations for bromide or TDS would be appropriate for FGD wastewater discharged from steam electric power plants upstream of drinking water intakes. EPA also stated its recommendation that the permitting authority notify any downstream drinking water treatment plants of the discharge of bromide.

In addition to the comments regarding EPA's analysis of bromide-related pollutant loadings, DBP formation, and health benefits (discussed in Section XII above), EPA also received many comments on the bromide-focused sub-options discussed in the 2019 proposal. Some commenters supported implementation of one or more of the proposed options, while other comments did not support the proposed options. Electric utility commenters were split. Some electric utility comments disagreed that these sub-options were warranted, with one trade association stating that these sub-options were not sufficiently described to allow meaningful comment. Other electric utility comments supported a monitoring-only approach. One commenter also provided an example of a site-specific approach on the Broad River, which is discussed further below. Environmental group commenters also disagreed with the proposed bromide sub-options; they argued that membrane filtration should be BAT, and thus these sub-options should either not be implemented or should be implemented on top of more stringent limitations. Drinking water utilities, though supporting the selection of membrane filtration over these sub-options, also recommended that in the absence of selecting more stringent limitations for discharges of FGD wastewater, EPA should finalize requirements for monitoring and a bromide minimization plan.

The final rule does not include limitations on bromide for FGD wastewater beyond the removals that would be required of plants choosing to meet the VIP limitations. EPA agrees with the wide variety of commenters that the selection of BAT based on the statutory factors, combined with the imposition of water quality-based effluent limitations where appropriate, rather than these sub-options, is the proper way to address impacts from bromides at this time.

The records for the 2015 rule, the 2019 proposal, and this final rule continue to suggest that permitting authorities should consider establishing water quality-based effluent limitations that are protective of populations served by downstream drinking water treatment plants. As described in Section XII, the analysis of changes in downstream bromide concentrations associated with changes in bromide discharges are concentrated at a small number of sites. This supports EPA's determination that potential discharges are best addressed using site-specific, water quality-based effluent limitations established by NPDES permitting authorities for the small number of steam electric power plants that may impact downstream drinking water treatment plants. Such an approach allows the permitting authority to tailor any monitoring or other requirement to the watershed and plants at issue, avoiding many of the individual concerns raised about specific monitoring programs. While EPA is not finalizing monitoring or other requirements, EPA believes that some information provided in comments discussed below may be particularly helpful for NPDES permitting authorities in devising a water quality-based approach.

Duke Energy provided an example of a successful site-specific bromide approach instituted on the Broad River in South Carolina.[174] As detailed in the settlement agreement attached to Duke Energy's public comment (EPA–HQ–OW–2009–0819–8320), this approach relied upon the establishment of an in-river bromide concentration of 0.6 ppm, below which there was ''. . . no significant impact upon the Downstream Plants' ability to meet the MCL for TTHMs.'' As part of this approach, the plant discharging bromide had to establish a collection point where the process water could be transferred off-site for treatment or disposal, and USGS data were used to determine the average flow of the river each week. Using the river flow from the previous week and the concentrations in the process water, the discharging plant had to determine the volume of process water to divert to the collection point. The discharging plant had to take 24-hour composite samples of its effluent one or more times per week and use those data to estimate in-river bromide concentrations, taking additional steps should those estimates exceed 0.6 ppm. EPA notes that this approach could be modified and applied at any particular watershed by determining the in-river bromide concentrations that affect the ability of drinking water treatment plants to meet the MCL for TTHMs, whether the bromide level is set higher or lower than the 0.6 ppm level established for the Broad River.

In December 2019, AWWA also finalized *Methods to Assess Anthropogenic Bromide Loads from Coal-fired Power Plants and Their Potential Effect on Downstream*

[173] Note: It is unlikely that a delay would be material after 2028, as all requirements of the rule will have been implemented industry-wide.

[174] See Attachment E of Document ID: EPA–HQ–OW–2009–0819–8320, available online at *www.regulations.gov*.

Drinking Water Utilities.[175] This document describes methodologies, data sources, and considerations for constructing an approach to bromide issues on a site-specific basis. This document presents additional data sources that could be used by NPDES permitting authorities to establish site-specific, water quality-based effluent limitations (see, *e.g.,* figure 29 in AWWA's document). The document also provides examples of where states have already taken similar action. For example, the AWWA cites California's 0.05 mg/L standard for in-river bromide to protect public health for specific waterways and drinking water treatment systems.

EPA also received a variety of comments on iodides. For a discussion of iodides, including data limitations and EPA's response to these comments, see Section 6 of the Supplemental TDD and EPA's response to comments document.

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

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

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

This final 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. EPA prepared an analysis of the estimated social costs and benefits associated with this action. This analysis is presented 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 analyze and update estimated incremental social costs and benefits of the final rule and revisions relative to the baseline.

Table XV–1 presents the annualized value of the social costs and benefits of the final rule. These costs and benefits are annualized over 27 years and discounted using three and seven percent discount rates. In the table, negative costs indicate avoided costs (*i.e.,* cost savings) and negative benefits indicate forgone benefits (positive benefits values represent realized benefits).

TABLE XV–1—TOTAL MONETIZED ANNUALIZED BENEFITS AND COSTS OF THE FINAL RULE AT 3% AND 7% DISCOUNT RATES AS COMPARED TO BASELINE

[Millions of 2018$; annualized] [a]

Discount rate	Total social costs [b]	Total monetized benefits [c d]
3%	−$127.1	−$1.7 to $43.3
7%	−$153.4	$6.5 to $45.9

[a] All social costs and benefits were annualized over 27 years using 3% and 7% discount rates. Negative costs indicate avoided costs and negative benefits indicate forgone benefits.
[b] Total social costs are compliance costs to plants accounting for when those costs are incurred.
[c] Total monetized benefits exclude other benefits discussed qualitatively.
[d] The range reflects the lower and upper bound willingness-to-pay estimates and air quality-related effects.

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

The final rule is an Executive Order 13771 deregulatory action. Details on the estimated cost savings of the final rule are in the RIA, and in Table XV–1 above.

C. Paperwork Reduction Act

OMB has previously approved the information collection requirements contained in the current 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 2040–0004. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

EPA estimated small changes in monitoring costs at steam electric power plants under the final rule relative to the baseline. These changes apply to plants to which the subcategories are applicable. In some cases, in lieu of these monitoring requirements, plants will have additional paperwork burden such as that associated with certifications and applicable BMP plans. See Section VII of this preamble. However, some plants will also realize savings relative to the baseline by no longer monitoring pollutants discharged by some subcategories of EGUs and because their applicable limitations and standards are based on less costly technologies. EPA projects that the burden associated with the new paperwork requirements will be largely offset by the reduced burden associated with less monitoring; therefore, the Agency projects that the final rule will 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, EPA also does not expect the final rule to increase or decrease their burden. The final rule will not change permit application requirements or the associated review; the final rule will not affect the number of permits issued to steam electric power plants; nor will the final rule materially change the efforts involved in developing or reviewing such permits. Accordingly, EPA estimated no net change (*i.e.,* no increase or decrease) in the cost burden to federal or state governments or dischargers associated with the final rule. EPA does not believe that any updates are needed to that ICR so it has not submitted it to OMB for review under the PRA.

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 summarized below. For

[175] Availabile online at *www.awwa.org/Portals/0/AWWA/ETS/Resources/17861ManagingBromideREPORT.pdf?ver=2020-01-09-151706-107 (DCN SE08643).*

further details, including analysis of other regulatory options considered, see Chapter 8 of the RIA.

EPA estimates that 231 to 459 entities, of which 76 to 127 are small, own steam electric power plants to which the final rule applies. These small entities own a total of 138 steam electric power plants. EPA considered the impacts of the final rule on small businesses using a cost-to-revenue test. The analysis compares the cost of implementing controls for BA and FGD wastewater under the final rule to those costs under the baseline (which reflects the 2015 rule, as explained in Section V of this preamble). EPA used cost-to-revenue ratios of three percent and one percent as indicative of potentially significant impact. EPA's analysis shows that no small entities exceed the three percent impact threshold. Three small entities (one cooperative and two municipalities) are expected to incur costs equal to or greater than one percent (but less than three percent) of revenue to meet the 2015 rule. Cost savings provided under the final rule reduce to two the number of small entities incurring costs equal to or greater than one percent of revenue. The number of small entities exceeding the one percent impact threshold in the baseline is small in the absolute and represents a small percentage of the total estimated number of small entities; the cost savings provided by the final rule further support EPA's finding of no significant impact on a substantial number of small entities (No SISNOSE).

E. Unfunded Mandates Reform Act

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 changes in compliance requirements on small governments (governments with jurisdiction over populations of less than 50,000), EPA estimated the changes in costs for compliance with the final rule relative to the baseline for different categories of entities. The final rule results in lower compliance costs (cost savings) when compared to the baseline. Compared to $113.5 million in the baseline, the Agency estimates that the final rule will reduce the maximum cost in any one year to state, local, or tribal governments by −$74.1 million. Compared to $1,313 million in baseline, the incremental cost in any given year to the private sector under the final rule is −$914 million. From these incremental cost values, EPA determines that the final rule does not 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 final rule would affect small governments in a way that is disproportionately burdensome in comparison to the effect on large governments, EPA compared total incremental costs and incremental costs per plant for small governments and large governments. EPA also compared the changes in per plant costs incurred for small-government-owned plants with those incurred by non-government-owned plants. The Agency evaluated both average and maximum annualized incremental costs per plant. These analyses find that small governments will not be significantly or uniquely affected by the final rule. For further discussion, including results for other regulatory options, see Chapter 9 of the RIA.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. Under Executive Order (E.O.) 13132, 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 EPA consults with state and local officials early in development of the action.

EPA anticipates that the final rule will not impose incremental administrative burden on states due to issuing, reviewing, and overseeing compliance with discharge limitations and standards.

As detailed in Chapter 9 of the RIA in the docket for this action, EPA has identified 157 steam electric plants owned by state or local governments, of which 13 plants are estimated to incur costs to comply with the BA transport water and FGD limitations in the 2015 rule. However, the final rule provides estimated cost savings as compared to the baseline. The difference in the maximum annualized costs per plant under the final rule as compared to the baseline is −$1.2 million. Based on this information, EPA concludes that this action will 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.

EPA assessed potential tribal implications for the final rule arising from three main changes: (1) Direct compliance costs incurred by plants; (2) impacts on drinking water systems downstream from steam electric power plants; and (3) administrative burden on governments that implement the NPDES program.

Regarding direct compliance costs, EPA's analyses show that no steam electric power plants with BA transport water or FGD discharges are owned by tribal governments. Regarding impacts on drinking water systems, EPA identified 14 public water systems operated by tribal governments that may have waters that receive halogen discharges from steam electric power plants. These systems serve a total of approximately 28,000 people. EPA estimated changes in source water halogen concentrations for these systems under the final rule relative to the baseline. This analysis, which is described in Chapter 4 of the BCA report, finds very small changes in source water halogen concentrations between the baseline and the final rule. 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, EPA concludes that the final rule will not 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 EPA does not expect that the environmental health risks or safety risks associated with steam electric power plant discharges addressed by this action present a disproportionate risk to children. This action's health risk assessments are described in Chapters 4 and 5 of the BCA report and are summarized below.

EPA identified several ways in which this final rule could affect children, including potentially increasing health risks due to an increase in exposure to pollutants present in steam electric power plant FGD wastewater and BA transport water discharged, and through those pollutants' potential impacts on public water systems' source water quality. This increase arises from less stringent pollutant limitations and later deadlines for meeting effluent limitations under the final rule relative to the baseline. In particular, EPA quantified the changes in IQ losses from lead exposure among pre-school children and from mercury exposure *in utero* deriving from maternal fish consumption under the final rule relative to the baseline. EPA also estimated changes in the number of children with very high blood lead concentrations. Finally, EPA estimated changes in concentrations of halogens in source waters for drinking water treatment plants. Under certain circumstances, halogens can contribute to the formation of halogenated disinfection byproducts in drinking water, for which there is evidence of a linkage to bladder cancer incidence. EPA did not estimate children-specific exposure to changes in halogen concentrations because these adverse health effects normally follow long-term exposure. These analyses show that today's final rule will 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 final rule 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 the final rule will not reduce electricity production by more than 1 billion kilowatt hours per year or by 500 megawatts of installed capacity, nor will the final rule increase U.S. dependence on foreign supplies of energy. For details on the potential energy effects of the other regulatory options considered, see Section 10.7 in the RIA, available in the docket.

J. National Technology Transfer and Advancement Act

The final rule does not involve technical standards.

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

The EPA believes that this action may have disproportionate effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). EPA conducted two main analyses, described in Chapter 14 of the BCA, to evaluate the environmental justice (EJ) considerations for the final rule: (1) Summarizing the demographic characteristics of the households living in proximity to steam electric power plants, plant air emissions and surface water discharges, and to the downstream reaches affected by plant discharges; and (2) Analyzing the distribution of estimated human health impacts among minority and/or low-income populations from estimated changes in exposure to pollutants in drinking water, self-caught fish, and the air.

The first analysis provides insight on the distribution of estimated regulatory option effects (*e.g.,* estimated effects on water quality and air pollutant emissions) on communities in proximity to steam electric power plants. The second analysis seeks to provide more specific insight on the distribution of estimated changes in adverse health effects and benefits and to assess whether minority and/or low-income populations incur disproportionately high environmental impacts and/or will be disproportionately excluded from realizing benefits under the regulatory options.

Overall, the various analyses show that estimated environmental changes under the regulatory options analyzed, including the final rule, may affect minority and/or low income populations to different degrees across environmental media, exposure pathways, and over time, but the estimated effects (positive or negative) of the changes will be small.

Communities living near steam electric power plants (*i.e.,* up to 50 miles) tend to have a lower proportion of low-income households and minority population than the national average, when considered in the aggregate, but there may be localized EJ considerations for some communities near individual plants (up to 50 miles) that have higher proportions of low-income or minority populations than the national and/or state average.

EPA's analysis considered the distribution of estimated effects on populations near both immediate and downstream reaches, in downstream PWS service areas, and in adjacent airsheds to assess whether low-income and/or minority populations may be disproportionately affected by changes under the final rule. The analysis shows that the EJ population subgroups are not excluded from the benefits of the final rule. For example, projected air quality changes under the final rule may disproportionately benefit minority and low-income populations based on the socioeconomic characteristics of populations of counties with changes in $PM_{2.5}$ and ozone levels during the period of analysis. Additionally, estimated foregone benefits related to water quality changes may disproportionately affect minority and subsistence fisher populations. However, the magnitude of the changes (positive and negative) and associated benefits (including foregone benefits) is small, relative to the baseline, both overall across the exposed population, and across socioeconomic and fisher subgroups..

L. Congressional Review Act (CRA)

This action is subject to the CRA, and EPA will submit a rule report to each House of 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. These terms are provided for convenience to the reader and they are not regulatory definitions with the force or effect of law, nor are they to be used as guidance for implementation of this final rule.

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 the organism.

BMP. Best management practice.

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

BA Purge Water. The water discharged from a wet BA handling system that recycles some, but not all, of its BA transport water.

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.

CSC. Compact Submerged Conveyor.

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 plant 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 that is collected or channeled by man; discharges through pipes, sewers, or other conveyances owned by a state, municipality, or other person that do not lead to a treatment works; and discharges through pipes, sewers, or other conveyances that lead into privately owned treatment works. This term does not include addition of pollutants by any ''indirect discharger.''

Direct discharger. A plant 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 EGU. It includes systems that collect and convey the bottom ash without using any water, as well as systems in which BA is quenched in a water bath and then mechanically or pneumatically conveyed away from the EGU. 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 that 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.

E.O. 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 FA. 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 or plant 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 EGU in a water-filled trough. The water bath in the trough quenches the hot BA as it falls from the EGU and seals the EGU 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 EGU 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 that causes it to behave like a fluid.

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

Point source. Any discernible, 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, 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 that is used in the treatment (including recycling and reclamation) of municipal sewage or industrial wastes of a liquid nature. 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 and 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 EGU, 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 EGU, 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 EGU 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.

Andrew Wheeler,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends 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) to read as follows.

§ 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, FGD paste equipment cleaning water, treated FGD wastewater permeate or distillate used as boiler makeup water, or water 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), FGD paste equipment cleaning water, or bottom ash 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), in which case it means October 13, 2021), unless the permitting authority establishes a later date, after receiving site-relevant 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, lime, Portland cement, and/or other pozzolanic material prior to being landfilled, and which is engineered to form a solid through pozzolanic reactions.

(v) The term ''FGD paste equipment cleaning water'' means any wastewater generated from the cleaning of pugmills, piping, or other equipment used to make, process, or transport FGD paste from its point of generation to a landfill.

(w) The term ''permanent cessation of coal combustion'' means the owner or operator certifies under § 423.19(f) that an electric generating unit will cease combustion of coal no later than December 31, 2028.

(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 ''capacity utilization rating'' means the total MWh production of an electric generating unit over a calendar year divided by the product of the number of hours in that year times the nameplate capacity.

(z) The term ''low utilization electric generating unit'' means any electric generating unit for which the facility owner certifies, and annually recertifies, under § 423.19(e) that the two-year average annual capacity utilization rating is less than 10 percent.

(aa) The term ''primary active wetted bottom ash system volume'' means the maximum volumetric capacity of bottom ash transport water in all non-redundant piping (including recirculation piping) and primary bottom ash collection and recirculation loop tanks (*e.g.,* bins, troughs, clarifiers, and hoppers) of a wet bottom ash system, excluding the volumes of surface impoundments, secondary bottom ash system equipment (*e.g.,* installed spares, redundancies, and maintenance tanks), and non-bottom ash transport systems that may direct process water to the bottom ash.

(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 ''bottom ash purge water'' means any water being discharged subject to § 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) to read as follows.

§ 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 purge water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration listed in the table 7:

TABLE 7 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 paragraphs (g)(1)(i); (g)(2) and (g)(3)(i);

■ b. Revising paragraphs (k)(1)(i) and (k)(2);

■ c. Adding paragraphs (k)(3), and (o).

The additions and revisions 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 1 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 October 13, 2021, 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 5 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	8
Mercury, total (ng/L)	103	34
Selenium, total (ug/L)	70	29
Nitrate/nitrite as N (mg/L)	4	3

* * * * *

(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 submitted a certification pursuant to § 423.19(f), 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 October 13, 2021, 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.

TABLE 6 TO PARAGRAPH (g)2)(ii)

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)	11	8
Mercury, total (ng/L)	788	356

(iii) For FGD wastewater discharges from a low utilization electric generating unit, 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 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 October 13, 2021, 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.

(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 7 OF 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	NA
Mercury, total (ng/L)	23	10
Selenium, total (ug/L)	10	NA
Nitrate/Nitrite (mg/L)	2.0	1.2
Bromide (mg/L)	0.2	NA
TDS (mg/L)	306	149

* * * * *

(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 October 13, 2021, but no later than December 31, 2025. 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. 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, it ceases to be bottom ash transport water, and instead is FGD wastewater, which must meet the requirements in paragraph (g) 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 are generated from storm events exceeding a 10-year storm event of 24-hour or longer duration (*e.g.,* 30-day storm event) and cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment; or

(*2*) To maintain system water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is not feasible; or

(*3*) To maintain system water chemistry where installed equipment at the facility is unable to manage pH, corrosive substances, substances or conditions causing scaling, or fine particulates to below levels which impact system operation or maintenance; or

(*4*) To conduct maintenance not otherwise included in paragraphs (k)(2)(i)(A) (*1*), (*2*), or (*3*) of this section and not exempted from the definition of transport water in § 423.11(p), and when water volumes cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment.

(B) The total volume that may 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. The total volume of the discharge authorized in this subsection shall be determined on a case-by-case basis by the permitting authority and in no event shall such discharge exceed a 30-day rolling average of ten percent of the primary active wetted bottom ash system volume. The volume of daily discharges used to calculate the 30-day rolling average shall be calculated using measurements from flow monitors.

(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 to the permitting authority that it will cease combustion of coal pursuant to § 423.19(f), 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) For bottom ash transport water generated by a low utilization electric generating unit, 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.

(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, 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*) To any other mechanisms not specified above.

(B) Water 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*) Any other mechanisms not specified above.

(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) Segregation of bottom ash transport water from other process water.

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

(F) Utilization of ''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) Performance of 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), remote mechanical drag system).

(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.

* * * * *

(o)(1) Transfer between applicable limitations in a permit. Where, in the permit, the permitting authority has included alternative limits subject to eligibility requirements, upon timely notification to the permitting authority under § 423.19(i), a facility can become subject to the alternative limits under the following circumstances:

(i) On or before December 31, 2023 a facility may convert:

(A) From limitations for electric generating units permanently ceasing coal combustion under paragraphs (g)(2)(i) or (k)(2)(ii) of this section to limitations for low utilization electric generating units under paragraphs (g)(2)(iii) or (k)(2)(iii) of this section; or

(B) From voluntary incentives program limitations under paragraph (g)(3)(i) of this section or generally applicable limitations under paragraph (k)(1)(i) of this section to limitations for low utilization electric generating units under paragraphs (g)(2)(iii) or (k)(2)(iii) of this section.

(ii) On or before December 31, 2025 a facility may convert

(A) From voluntary incentives program limitations under paragraph (g)(3)(i) of this section to limitations for electric generating units permanently ceasing coal combustion under paragraph (g)(2)(i) of this section; or

(B) From limitations for electric generating units permanently ceasing coal combustion under paragraphs (g)(2)(i) or (k)(2)(ii) of this section to voluntary incentives program limitations under paragraphs (g)(3)(i) of this section or generally applicable limitations under (k)(1)(i) of this section; or

(C) From limitations for low utilization electric generating units under paragraphs (g)(2)(iii) or (k)(2)(iii) of this section to generally applicable limitations under paragraphs (g)(1)(i) or (k)(1)(i) of this section; or

(D) From limitations for low utilization electric generating units under paragraphs (g)(2)(iii) or (k)(2)(iii) of this section to voluntary incentives program limitations under paragraphs (g)(3)(i) of this section or generally applicable limitations under paragraph (k)(1)(i) of this section; or

(E) From limitations for low utilization electric generating units under paragraphs (g)(2)(iii) or (k)(2)(iii) of this section to limitations for electric generating units permanently ceasing coal combustion under paragraphs (g)(2)(i) and (k)(2)(ii) of this section.

(2) A facility must be in compliance with all of its currently applicable requirements to be eligible to file a notice under § 423.19(i) and to become subject to a different set of applicable requirements under paragraph (o)(1) of this section.

(3) Where a facility seeking a transfer under paragraph (o)(1)(ii) of this section is currently subject to more stringent limitations than the limitations being sought, the facility must continue to meet those more stringent limitations.

2. Amend § 423.16 by revising paragraphs (e) and (g) 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 to the permitting authority that it will cease the coal combustion pursuant to § 423.19(f), 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 3 to this paragraph (e)(1). Dischargers must meet the standards in this paragraph by October 13, 2023 except as provided for in paragraph (e)(2) of this section. These standards apply to the discharge of FGD wastewater generated on and after October 13, 2023.

TABLE 3 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	8
Mercury, total (ng/L)	103	34
Selenium, total (ug/L)	70	29
Nitrate/nitrite as N (mg/L)	4	3

(2)(i) For FGD wastewater discharges from a low utilization electric generating unit, 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 4 to paragraph (e)(2)(ii). Dischargers must meet the standards in this paragraph by October 13, 2023.

(ii) If any low utilization electric generating unit fails to timely recertify that the two year average capacity utilization rating of such a electric generating unit is below 10 percent 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 3 to paragraph (e)(1).

TABLE 4 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) 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 electric generating unit, and that the owner has not certified to the permitting authority that the electric generating unit will cease the cessation of coal combustion pursuant to § 423.19(f), 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 October 13, 2023. 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 the table in paragraph (e) of this section.

(2)(i) 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:

(A) To maintain system water balance when precipitation-related inflows are generated from a 10-year storm event of 24-hour or longer duration (*e.g.,* 30-day storm event) and cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment; or

(B) To maintain system water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is feasible; or

(C) To maintain system water chemistry where current operations at the facility are unable to currently manage pH, corrosive substances, substances or conditions causing scaling, or fine particulates to below levels which impact system operation or maintenance; or

(D) To conduct maintenance not otherwise included in paragraphs (g)(2)(i)(A)(*1*), (*2*), or (*3*) of this section and not exempted from the definition of transport water in§ 423.11(p), and when water volumes cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment.

(ii) The total volume that may be discharged to a POTW for the above activities shall be reduced or eliminated to the extent achievable as determined by the control authority. The control authority may also include control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice. In no event shall the total volume of the discharge exceed a 30-day rolling average of ten percent of the primary active wetted bottom ash system volume. The volume of daily discharges used to calculate the 30-day rolling average shall be calculated using measurements from flow monitors.

(iii) For bottom ash transport water generated by a low utilization electric generating unit, 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).

■ 5. Add § 423.18 to read as follows.

§ 423.18 Permit conditions.

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

(a) An electric generating unit shall qualify as a low utilization electric generating unit or permanently ceasing the combustion of coal by December 31, 2028, if such qualification would have been demonstrated absent the following qualifying event:

(1) An emergency order issued by the Department of Energy under Section 202(c) of the Federal Power Act,

(2) A reliability must run agreement issued by a Public Utility Commission, or

(3) Any other reliability-related order or agreement issued by a competent electricity regulator (*e.g.,* an independent system operator) which results in that electric generating unit operating in a way not contemplated when the certification was made; or

(4) The operation of the electric generating unit was necessary for load balancing in an area subject to a declaration under 42 U.S.C. 5121 *et seq.,* that there exists:

(i) An ''Emergency,'' or

(ii) A ''Major Disaster,'' and

(iii) That load balancing was due to the event that caused the ''Emergency'' or ''Major Disaster'' in paragraph (a)(4) of this section to be declared,

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

■ 6. Add § 423.19 to read as follows.

§ 423.19 Reporting and recordkeeping requirements.

(a) Discharges subject to this part must comply with the following additional reporting requirements.

(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 October 13, 2023 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) Material assumptions, information, and calculations used by the certifying professional engineer to determine the primary active wetted bottom ash system volume.

(F) A list of all potential discharges under § 423.13(k)(2)(i)(A)(*1*) through (4) or § 423.16(g)(2)(i)(A) through (D), the expected volume of each discharge, and the expected frequency of each discharge.

(G) Material assumptions, information, and calculations used by the certifying professional engineer to determine the expected volume and frequency of each discharge including a narrative discussion of why such water cannot be managed within the system and must be discharged.

(H) A list of all wastewater treatment systems at the facility currently, or otherwise required by a date certain under this section.

(I) A narrative discussion of each treatment system including the system type, design capacity, and current or expected operation.

(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 within two years of October 13, 2021, whichever is later, or to the control authority no later than October 13, 2023 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 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 (c)(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 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 electric generating units.

(1) *Notice of Planned Participation.* For sources seeking to qualify as a low utilization electric generating units, a Notice of Planned Participation shall be submitted to the permitting authority or control authority no later than October 13, 2021.

(2) *Contents.* A Notice of Planned Participation shall identify the potential low utilization electric generating unit. The notice shall also include a statement of at least two years' capacity utilization rating data for the most recent two years of operation of each low utilization electric generating unit and a statement that the facility has a good faith belief that each low utilization electric generating unit will continue to operate at the required capacity utilization rating. Where the most recent capacity utilization rating does not meet the low utilization electric generating unit requirement, a discussion of the projected future utilization shall be provided, including material data and assumptions used to make that projection.

(3) *Initial and annual certification statement.* For sources seeking to qualify as a low utilization electric generating unit under this part, an initial certification shall be made to the permitting authority, or to the control authority in the case of an indirect discharger, no later than December 31, 2023, 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 electricity production data to the Energy Information Administration.

(4) *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 capacity utilization rating.

(f) Requirements for units that will achieve permanent cessation of coal combustion by December 31, 2028.

(1) *Notice of Planned Participation.* For sources seeking to qualify as an electric generating unit that will achieve permanent cessation of coal combustion by December 31, 2028, under this part, a Notice of Planned Participation shall be made to the permitting authority, or to the control authority in the case of an indirect discharger, no later than October 13, 2021.

(2) *Contents.* A Notice of Planned Participation shall identify the electric generating units intended to achieve the permanent cessation of coal combustion. A Notice of Planned Participation shall include the expected date that each electric generating unit is projected to achieve permanent cessation of coal combustion, whether each date represents a retirement or a fuel conversion, whether each retirement or fuel conversion has been approved by a regulatory body, and what the relevant regulatory body is. The Notice of Planned Participation shall also include a copy of the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, certification of electric generating unit cessation under 40 CFR 257.103(b), or other documentation supporting that the electric generating unit will permanently cease the combustion of coal by December 31, 2028. The Notice of Planned Participation shall also include, for each such electric generating unit, a timeline to achieve the permanent cessation of coal combustion. Each timeline shall include interim milestones and the projected dates of completion.

(3) *Annual Progress Report.* Annually after submission of the Notice of Planned Participation in paragraph (f)(1) of this section, a progress report shall be filed with the permitting authority, or control authority in the case of an indirect discharger.

(4) *Contents.* An Annual Progress Report shall detail the completion of any interim milestones listed in the Notice of Planned Participation since the previous progress report, provide a narrative discussion of any completed, missed, or delayed milestones, and provide updated milestones.

(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 paragraph § 423.18, and for each instance that § 423.18 is applied, a one-time certification shall be submitted to the permitting authority, or control authority in the case of an indirect discharger, no later than:

(A) In the case of an order or agreement under § 423.18(a)(1), 30 days from receipt of the order or agreement attached pursuant to paragraph (g)(2)(B) of this section; or

(B) In the case of an "Emergency" or "Major Disaster" under § 423.18(a)(2), 30 days from the date that a load balancing need arose.

(2) *Contents.* A certification statement must include the following:

(A) The qualifying event from the list in § 423.18(a), the individual or entity that issued or triggered the event, and the date that such an event was issued or triggered.

(B) A copy of any documentation of the qualifying event from the individual or entity listed under paragraph (g)(2)(A) of this section, or, where such documentation does not exist, other documentation with indicia of reliability for the permitting authority to confirm the qualifying event.

(C) An analysis and accompanying narrative discussion which demonstrates that a electric generating unit would have qualified for the subcategory at issue absent the event detailed in paragraph (g)(2)(A), including the material data, assumptions, and methods used.

(3) *Termination of need statement.* For sources filing a certification statement under paragraph (g)(1) above, and for each such certification statement, a one-time termination of need statement shall be submitted to the permitting authority, or control authority in the case of an indirect

discharger, no later than 30 days from when the source is no longer subject to increased production from the qualifying event.

(4) *Contents.* A termination of need statement must include a narrative discussion including the date the qualifying event terminated, or if it has not terminated, why the source believes the capacity utilization will no longer be elevated to a level requiring the protection of § 423.18.

(h) Requirements for facilities voluntarily meeting the limits in 423.13(g)(3)(i).

(1) *Notice of Planned Participation.* For sources opting to comply with the Voluntary Incentives Program requirements of section 423.13(g)(3)(i) by December 31, 2028, a Notice of Planned Participation shall be made to the permitting authority no later than October 13, 2021.

(2) *Contents.* A Notice of Planned Participation shall identify the facility opting to comply with the Voluntary Incentives Program requirements of 423.13(g)(3)(i), specify what technology or technologies are projected to be used to comply with those requirements, and provide a detailed engineering dependency chart and accompanying narrative demonstrating when and how the system(s) and any accompanying disposal requirements will be achieved by December 31, 2028.

(3) *Annual progress report.* After submission of the Notice of Planned Participation in paragraph (h)(1), a progress report shall be filed with the permitting authority, or control authority in the case of an indirect discharger.

(4) *Contents.* An Annual Progress Report shall detail the completion of interim milestones presented in the engineering dependency chart from the Notice of Planned Participation since the previous progress report, provide a narrative discussion of completed, missed, or delayed milestones, and provide updated milestones.

(5) *Rollover certification.* Where, prior to the effective date, a discharger has already provided a notice to the permitting authority of opting to comply with the Voluntary Incentives Program requirements of § 423.13(g)(i), such notice will satisfy paragraph (h)(1) of this section. However, where details required by (h)(2) of this sectionwere missing from the previously provided notice, those details must be provided in the first Annual Progress Report, no later than October 13, 2021.

(i) Requirements for facilities seeking to transfer between applicable limitations in a permit under § 423.13(o).

(1) *Notice of Planned Participation.* For sources which have filed a Notice of Planned Participation under paragraphs (e)(1), (f)(1), or (h)(1) of this section and intend to make changes that would qualify them for a different set of requirements under § 423.13(o), a Notice of Planned Participation shall be made to the permitting authority, or to the control authority in the case of an indirect discharger, no later than the dates stated in § 423.13(o)(1).

(2) *Contents.* A Notice of Planned Participation shall include a list of the electric generating units for which the source intends to change compliance alternatives. For each such electric generating unit, the notice shall list the specific provision under which this transfer will occur, the reason such a transfer is warranted, and a narrative discussion demonstrating that each electric generating unit will be able to maintain compliance with the relevant provisions.

(j) *Notice of material delay.* (1) *Notice.* Within 30 days of experiencing a material delay in the milestones set forth in paragraphs (f)(2) or (h)(2) of this section and where such a delay may preclude permanent cessation of coal combustion or compliance with the voluntary incentives program limitations by December 31, 2028, a facility shall file a notice of material delay with the permitting authority, or control authority in the case of an indirect discharger.

(2) *Contents.* The contents of such a notice shall include the reason for the delay, the projected length of the delay, and a proposed resolution to maintain compliance.

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