



**Supplemental Technical  
Development Document for  
Proposed Revisions to the  
Effluent Limitations  
Guidelines and Standards  
for the Steam Electric Power  
Generating Point Source  
Category**

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# **Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category**

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U.S. Environmental Protection Agency  
Office of Water (4303T)  
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## SECTION 1 BACKGROUND

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This Supplemental Technical Development Document describes the supporting information for the Agency's reconsideration of effluent limitations guidelines and standards (ELGs) for the Steam Electric Power Generating Point Source Category, promulgated on November 3, 2015 (referred to throughout this document as the “2015 rule”). Information on the 2015 Final Rule can be found at 80 FR 67838 (November 3, 2015) and in the September 2015 Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (821-R-15-007) (referred to throughout this document as the “2015 TDD”).

The EPA is conducting a new rulemaking regarding the appropriate technology bases and associated limitations for the best available technology economically achievable (BAT) effluent limitations and pretreatment standards for existing sources (PSES) applicable to flue gas desulfurization (FGD) wastewater and bottom ash transport water discharged from steam electric power plants. This document presents supporting information for proposed revisions to the 2015 rule, and supplements the 2015 TDD by summarizing the EPA’s data collection efforts following the promulgation of the 2015 rule, updates to the industry profile (e.g., retirements, FGD wastewater treatment technology upgrades, and bottom ash handling system conversions) and impacts from other rulemakings impacting the industry, adjustments to methodologies for estimating the costs, pollutant removals, and non-water quality environmental impacts associated with FGD wastewater treatment and management of bottom ash transport water, and the derivation of the proposed effluent limitations.

In addition to this report, other supporting reports include:

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

The ELGs for the Steam Electric Power Generating Category are based on data generated or obtained in accordance with the EPA’s Quality Policy and Information Quality Guidelines. The

EPA’s quality assurance (QA) and quality control (QC) activities for this rulemaking include developing, approving, and implementing Quality Assurance Project Plans for the use of environmental data generated or collected from sampling and analyses, existing databases, and literature searches, and for developing any models that use environmental data.

## **1.1 LEGAL AUTHORITY**

The EPA is proposing to revise the ELGs for the Steam Electric Power Generating Point Source Category (40 CFR 423) under the authority of sections 301, 304, 306, 307, 308, 402, and 501 of the Clean Water Act, 33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342, and 1361.

Under the Act, the EPA is required to establish the effluent limitations guidelines and standards as summarized in the 2015 TDD.

## **1.2 REGULATORY HISTORY OF THE STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY**

The EPA, on September 30, 2015, finalized the 2015 rule revising the regulations for the Steam Electric Power Generating point source category (40 CFR 423). The 2015 rule set the first federal limitations on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry.

Prior to the 2015 rule, regulations for the industry had last been updated in 1982. The 1982 rule focused on settling out particulates rather than treating dissolved pollutants. New technologies for generating electric power and the widespread implementation of air pollution controls have altered wastewater streams or created new wastewater streams at many power plants, particularly coal-fired power plants. Discharges of these wastestreams include arsenic, lead, mercury, selenium, chromium, and cadmium.

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

Compared to the 1982 rule, the 2015 rule was estimated to reduce the annual amount of toxic metals, nutrients, and other pollutants that steam electric power plants are allowed to discharge by 1.4 billion pounds. Estimated annual compliance costs for the final rule were \$480 million (in 2013 dollars). Estimated benefits associated with the rule were \$451 to \$566 million (in 2013 dollars).

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. On March 24, 2017, the

Utility Water Act Group (UWAG) submitted to the EPA an administrative petition for reconsideration of the 2015 rule. Also, on April 5, 2017, the Small Business Administration (SBA) submitted an administrative petition for reconsideration of the 2015 rule.

On April 25, 2017, the EPA responded to these petitions by publishing a postponement of the 2015 rule compliance deadlines that had not yet passed, under Section 705 of the Administrative Procedure Act (APA). 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 bottom ash transport water. The Fifth Circuit Court of Appeals heard the consolidated petitions for review of the 2015 rule and subsequently granted the EPA's request to sever and hold in abeyance aspects of the litigation related to the FGD wastewater and bottom ash transport water limitations and standards. With respect to the remaining claims related to limitations applicable to legacy wastewater and leachate, which are not at issue in this proposed rulemaking, the Fifth Circuit issued a decision on April 12, 2019, vacating those limitations as arbitrary and capricious under the Administrative Procedure Act and unlawful under the CWA, respectively.

In September 2017, the EPA finalized a rule, using notice-and-comment procedures, postponing the earliest compliance dates for the new, more stringent BAT effluent limitations and PSES for FGD wastewater and bottom ash transport water in the 2015 rule, from November 1, 2018 to November 1, 2020. The EPA also withdrew its prior action taken pursuant to Section 705 of the APA.

### **1.3 OTHER KEY REGULATORY ACTIONS AFFECTING MANAGEMENT OF STEAM ELECTRIC POWER GENERATING WASTEWATERS**

The EPA previously described other Agency actions to reduce emissions, discharges, and other environmental impacts associated with steam electric power plants (see 2015 TDD). Since the promulgation of the 2015 final rule, regulatory changes have been identified in the Clean Power Plan (CPP), the Affordable Clean Energy (ACE) rule, and the Coal Combustion Residuals (CCR) rule. This section provides a brief overview of these recent changes to the regulatory requirements for steam electric power plants.

#### **1. Clean Power Plan and Affordable Clean Energy**

The final 2015 CPP established carbon dioxide (CO<sub>2</sub>) emission guidelines for fossil-fuel fired power plants based in part on shifting from one type of energy source to another at the fleet-wide level. On February 9, 2016, the U.S. Supreme Court stayed implementation of the CPP pending judicial review.

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

inform the state’s development of standards of performance to reduce CO<sub>2</sub> emissions from existing coal-fired electric utility generating units consistent with the EPA’s role as defined in the CAA.

ACE establishes heat rate improvement (HRI), or efficiency improvement, as the best system of emissions reduction (BSER) for CO<sub>2</sub> from coal-fired electric utility generating units.<sup>1</sup> By employing a broad range of HRI technologies and techniques, electric utility generating units can more efficiently generate electricity with less carbon intensity.<sup>2</sup> The BSER is the best technology or other measure that has been adequately demonstrated to improve emissions performance for a specific industry or process (a “source category”). In determining the BSER, the EPA considers technical feasibility, cost, non-air quality health and environmental impacts, and energy requirements. The BSER must be applicable to, at, and on the premises of an affected facility. ACE lists six HRI “candidate technologies,” as well as additional operating and maintenance practices.<sup>3</sup> For each candidate technology, the EPA has provided information regarding the degree of emission limitation achievable through application of the BSER as ranges of expected improvement and costs.

The 2015 rule analyses incorporated compliance costs associated with the 2015 CPP, resulting in, among other things, baseline retirements associated with that rule in the Integrated Planning Model (IPM). As noted in the ACE RIA, while the final repeal of the CPP has been promulgated, the business-as-usual economic conditions achieved the carbon reductions laid out in the final CPP. The EPA used the IPM version 6 to analyze today’s proposal to be consistent with the base case analyses done for the ACE final rule. The Agency also performed a sensitivity analysis, following promulgation of the ACE final rule, that estimates the impacts of the preferred option relative to a baseline that includes the ACE rule. See additional discussion of IPM in Section VIII of the preamble.

## 2. Coal Combustion Residuals (CCR) Final Rule

On April 17, 2015, the Agency published the Disposal of Coal Combustion Residuals from Electric Utilities final rule. This rule finalized national regulations to provide a comprehensive set of requirements for the safe disposal of CCRs, commonly known as coal ash, from coal-fired power plants. The final CCR rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The rule establishes 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 address the risks from coal ash disposal: contaminants leaking into ground water, contaminants blowing into the air as dust, and the catastrophic failure

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<sup>1</sup> Heat rate is a measure of the amount of energy required to generate a unit of electricity.

<sup>2</sup> An improvement to heat rate results in a reduction in the emission rate of an electric utility generating unit (in terms of CO<sub>2</sub> emissions per unit of electricity produced).

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

of coal ash surface impoundments. The CCR rule also sets out recordkeeping and reporting requirements, as well as requiring each power plant to establish and post specific information on a publicly-accessible website. This final CCR rule also supports the responsible recycling of CCRs by distinguishing safe, beneficial use from disposal.

As explained in the 2015 rule, the ELGs and CCR rules may affect the same unit or activity at a power plant. In finalizing both of those rules in 2015, the EPA coordinated the two rules to minimize the overall complexity and to facilitate implementation of engineering, financial, and permitting activities. The coordination of the two rules continues to be a major consideration in the development of this proposal. The EPA's analysis of this proposal incorporates the same approach used in the 2015 rule to estimate how the CCR rule may affect surface impoundments and the ash handling systems and FGD treatment systems that send wastes to those impoundments. However, as a result of the D.C. Circuit Court rulings in *USWAG v. EPA*, No. 15-1219 (DC Cir. 2018) and *Waterkeeper Alliance Inc, et al. v. EPA*, No. 18-1289 (DC Cir. 2019), amendments to the CCR rule are being proposed which would establish a deadline of August 2020 by which date all unlined surface impoundments<sup>4</sup> must cease receiving waste, subject to certain exceptions.

In order to account for the CCR rule proposed amendments in this proposed rule, the EPA conducted a sensitivity analysis to determine how the closure of unlined surfaced impoundments would impact the compliance cost and pollutant loading estimates, see Section 3.3 for more details.

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<sup>4</sup> Due to the Court vacatur of 40 CFR 257.71(a)(1)(i) (provision for clay-lined surface impoundments) clay-lined surface impoundments are currently considered unlined.

## SECTION 2

# DATA COLLECTION ACTIVITIES

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The EPA collected and evaluated information from various sources in the course of developing the 2015 rule, as described in Section 3 of the 2015 TDD. As part of this proposed rule, the EPA collected additional data to update the industry profile, identify the power plants affected by the rule, reevaluate industry subcategorization, update plant-specific operations and wastewater characteristics, and determine the technology options, compliance costs, baseline pollutant loadings, changes in post-compliance pollutant loadings, and non-water-quality environmental impacts. This section summarizes the following additional data collection activities for FGD wastewater and bottom ash transport water as they relate to technical aspects of the proposed rule:

- Site visits (Section 2.1).
- Industry-submitted data (Section 2.2).
- Technology vendor data (Section 2.3).
- Other data sources (Section 2.4).
- Protection of confidential business information (Section 2.5).

### 2.1 SITE VISITS

After promulgating the 2015 rule, the EPA conducted seven site visits to power plants in five states between October and December 2017 to update information on methods of managing FGD wastewater and bottom ash transport water. Table 2-1 lists the site visits conducted following the 2015 rule. The EPA used information gathered in support of the 2015 rule, information from industry outreach, and publicly available plant-specific information to identify power plant operations of interest. The EPA prioritized plants engaged in FGD wastewater treatment pilot studies or with updated FGD treatment or bottom ash handling systems. The EPA made pre-site-visit phone calls to confirm plant operations and to select plants for site visits. The specific objectives of these site visits were to:

- Gather general information about each plant's operations.
- Gather information on pollution prevention and wastewater treatment and operations.
- Gather information about FGD wastewater treatment from ongoing pilot studies or laboratory-scale studies.
- Gather information on conversions to bottom ash handling systems.

The EPA revisited four power 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. The EPA visited these plants to collect performance data and learn more about the technologies they were testing to treat FGD wastewater. Following the 2015 rule, the EPA visited plants that had implemented new FGD wastewater treatment technologies or bottom ash



handling systems to learn more about implementation timing, start-up and operation, and compliance costs.

**Table 2-1. Site Visits Conducted Supporting the Proposed Rule**

Plant Name, Location	Month/Year of Site Visit
Conemaugh, <i>Pennsylvania</i>	Oct 2017
Bowen, <i>Georgia</i>	Nov 2017
Miller, <i>Alabama</i>	Nov 2017
Belews Creek, <i>North Carolina</i>	Dec 2017
Mill Creek, <i>Kentucky</i>	Dec 2017
Sutton, <i>North Carolina</i>	Dec 2017
Trimble County, <i>Kentucky</i>	Dec 2017

The EPA also visited two North Carolina drinking water treatment plants downstream of steam electric power plant outfalls in December 2017. The objective of the site visits was to investigate the impacts to drinking water treatment plants as well as the efforts plants were making to mitigate increased formation of disinfection byproducts (ERG, 2018). Refer to the 2019 Supplemental EA for a more detailed discussion on sources of bromides found in FGD wastewater and their impacts to downstream drinking water intakes.

## 2.2 INDUSTRY-SUBMITTED DATA

The EPA obtained information on steam electric processes, wastewater treatment technologies, and wastewater characteristics directly from the industry through a Clean Water Act (CWA) Section 308 request, voluntary bottom ash sampling data request, and other industry data provided during the reconsideration of the 2015 rule. Sections 2.2.1 and 2.2.2 summarize the industry-submitted data collected.

### 2.2.1 Clean Water Act Section 308 Industry Request for FGD Wastewater

Under the authority of Section 308 of the CWA (33 U.S.C. 1318), the EPA requested the following information for coal-fired power plants from nine steam electric power companies that generate FGD wastewater:

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

The EPA used this information to learn more about the performance of FGD wastewater treatment systems, inform FGD wastewater limitations development, learn more about plant-

specific halogen usage, and obtain information useful for estimating the cost of installing candidate treatment technologies. The EPA used this information to supplement the data collected in support of the 2015 rule. As described in Section 3.4 of the 2015 TDD, between July 2007 and April 2011, the EPA conducted a sampling program at 17 different steam electric power plants in the United States and Italy to collect wastewater characterization data and treatment performance data. As needed, the EPA conducted follow-up meetings and conference calls with industry representatives to discuss and clarify these data.

### **2.2.2 Voluntary Sampling Program for Bottom Ash Transport Water**

In order to further supplement the bottom ash transport water characterization data set used to support the 2015 rule analyses, the EPA invited seven steam electric power plants to participate in a voluntary bottom ash transport water sampling program. The EPA requested information from steam electric power plants operating impoundments that predominantly contain bottom ash transport water. Plants were asked to provide analytical data for ash impoundment effluent and untreated bottom ash transport water (i.e., ash impoundment influent). Two plants chose to participate in the voluntary bottom ash sampling program and provided the EPA with the bottom ash data requested.

## **2.3 TECHNOLOGY VENDOR DATA**

The EPA gathered data from technology vendors through presentations, conferences, site visits, meetings, and email and phone contacts regarding the FGD wastewater and bottom ash handling technologies used in the industry. The data collected informed the development of the technology costs and pollutant removal estimates for FGD wastewater and bottom ash transport water. The EPA participated in multiple technical conferences and reviewed the papers presented for relevant information to the proposed rule.

To gather FGD wastewater treatment information for the cost analyses, the EPA contacted companies that manufacture, distribute, or install various components of biological wastewater treatment, membrane filtration, or thermal evaporation systems. The EPA also contacted consulting firms that design and implement FGD wastewater treatment technologies. The vendors and consulting firms provided the following types of information for EPA's analyses:

- Operating details.
- Performance data where available.
- Equipment used in the system.
- Estimated capital and operating and maintenance (O&M) costs.
- System energy requirements.
- Timeline.

To gather information on bottom ash handling systems, the EPA also contacted vendors as well as consulting firms that design and implement these systems. The vendors and consulting firms provided the following types of information for EPA's analyses:

- Systems available for reducing or eliminating ash transport water.

- Equipment, modifications, and demolition required to convert wet sluicing systems to dry ash handling or closed-loop recycle systems.<sup>5</sup>
- Equipment that can be reused as part of the conversion from wet to dry handling or in a closed-loop recycle system.
- Outage time estimated for the different types of ash handling systems.
- Maintenance estimated for each type of system.
- Estimated capital and operating and maintenance (O&M) costs.

Cost information collected from technology vendors is further detailed in Section 5.

## 2.4 OTHER DATA SOURCES

The EPA obtained information on steam electric processes, wastewater treatment, wastewater characteristics, and regulations from sources including trade associations such as UWAG and the Electric Power Research Institute (EPRI), the U.S. Department of Energy (DOE), literature and Internet searches, and environmental groups. Sections 2.4.1 through 2.4.4 summarize the data collected from these additional sources during reconsideration of the 2015 rule.

### 2.4.1 Trade Associations

UWAG is an association of individual electric utilities and several national trade associations of electric utilities, including the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. The EPA met with UWAG to discuss approaches for managing discharges of FGD wastewater and bottom ash transport water.

EPRI conducts studies funded by the steam electric power generating industry to evaluate and demonstrate technologies that can potentially remove pollutants of concern from wastestreams or eliminate wastestreams using zero discharge technologies. The EPA reviewed 35 reports that EPRI voluntarily provided, or which already had been included in 308 responses, listed in Table 2-2. These reports were not part of the 2015 rule record, and contained information relevant to characteristics of FGD wastewater, FGD wastewater treatment pilot studies, bottom ash transport water characterization, bottom ash handling practices, and the effect of halogen additives on FGD wastewater.

**Table 2-2. EPRI Reports and Studies Reviewed by the EPA as Part of the Reconsideration of the 2015 rule**

Title of Report/Study	Date Published	Document Control Number
Pilot-Scale Demonstration of Hybrid Zero-Valent Iron Water Treatment Technology	April 2013	DCN SE06391A2

<sup>5</sup> Throughout this report, the EPA refers to bottom ash systems that eliminate the use of ash transport water as dry ash handling systems; however, some of these systems (e.g., mechanical drag system) still use water in a quench bath and, therefore, are not completely dry systems.

**Table 2-2. EPRI Reports and Studies Reviewed by the EPA as Part of the Reconsideration of the 2015 rule**

Title of Report/Study	Date Published	Document Control Number
Flue Gas Desulfurization (FGD) Wastewater Chemical Precipitation Bench-Scale Treatability Study	August 2015	DCN SE06391A2
Wastewater Minimization Using Water Pinch Analysis	November 2016	DCN SE06391A2
Physical/Chemical Treatment of Flue Gas Desulfurization Wastewater – Case Study 1	July 2015	DCN SE06391A2
Laboratory Evaluation of Arsenic Adsorption Media for Flue Gas Desulfurization Wastewater	October 2015	DCN SE06391A2
Field Evaluation of Online Selenium and Mercury Monitors	November 2017	DCN SE06391A2
Program on Technology Innovation: Review of Desalination Technology for Power Plants	December 2017	DCN SE06391A2
Program on Technology Innovation: Mineralogical Investigation of a Brine Encapsulated Monolith	December 2017	DCN SE06391A2
Biological Treatment of Flue Gas Desulfurization Wastewater at a Power Plant Burning Powder River Basin Coal - Pilot Demonstration with the ABMet Technology	March 2017	DCN SE06610A2
Conditions Impacting Treatment of Wet Flue Gas Desulfurization Wastewater	August 2017	DCN SE06850A3
Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges	September 2011	DCN SE06920
Mercury Control Update 2011	December 2011	DCN SE06948
Performance Evaluation of a Radial Deionization System for Flue Gas Desulfurization Wastewater Treatment	December 2013	DCN SE06949
Evaluation of Wet-to-Dry Retrofits for Bottom Ash Handling Systems at Coal-fired Power Plants Owned by a Midwestern Utility Company	November 2014	DCN SE06950
Effectiveness and Balance-of-Plant Impacts of Added Bromine	November 2013	DCN SE06951
State of Knowledge: Power Plant Wastewater Treatment – Membrane Technologies	August 2015	DCN SE06952
Performance Evaluation of a Vibratory Sheer Enhanced Processing Membrane System for FGD Wastewater Treatment	July 2014	DCN SE06953
Demonstration Development Project: Vortex-Based Antifouling Membrane System Treating Flue Gas Desulfurization Wastewater	October 2014	DCN SE06954
Demonstration Development Project: Feasibility of an Adiabatic Evaporator for Flue Gas Desulfurization Wastewater Zero Liquid Discharge Treatment Using Flue Gas Heat	May 2015	DCN SE06955
Program on Technology Innovation: Bromine Usage, Fate, and Potential Impacts for Fossil Fuel-Fired Power Plants	July 2014	DCN SE06956
2015 Impacts of Refined Coals and Additives	December 2015	DCN SE06957
Halogen Addition for Mercury Control and Related Balance-of-Plant Issues	December 2015	DCN SE06958
Landfill Leachate Characterization, Management and Treatment Options	November 2017	DCN SE06959

**Table 2-2. EPRI Reports and Studies Reviewed by the EPA as Part of the Reconsideration of the 2015 rule**

Title of Report/Study	Date Published	Document Control Number
Pilot Evaluation of Various Adsorption Media for FGD Wastewater Treatment	August 2015	DCN SE06960
Evaluation of Vacom One-Step System for Concentrating Flue Gas Desulfurization Wastewater	December 2015	DCN SE06961
Evaluating Pironox Advanced Reactive Media Process for Treating Flue Gas Desulfurization Wastewater: Effect of Bromine Addition of Wastewater Treatment	January 2016	DCN SE06962
Guidance Document for Management of Closed-Loop Bottom Ash Handling Water in Compliance with the 2015 Effluent Limitations Guidelines (ELGs)	December 2016	DCN SE06963
Characterizing Flue Gas Desulfurization Wastewater in Systems with Mercury and Air Toxics Control	February 2017	DCN SE06964
Wet Flue Gas Desulfurization Wastewater Physical/Chemical Treatment Guidelines	December 2016	DCN SE06965
Pilot Evaluation of the Sylvan Source Core Water Treatment System	April 2017	DCN SE06966
Materials Selection of Alloys in Forced Oxidation Wet Flue Gas Desulfurization Absorber Environments with Increased Halide Content	September 2016	DCN SE06967
Program on Technology Innovation: Alternative and Innovative Technologies for Coal Combustion Product Management	December 2016	DCN SE06968
Water Management—Evaluation of Treatment for Closed-Loop Bottom Ash Purges to FGD	December 2017	DCN SE06969
Evaporation Treatment of Flue Gas Desulfurization Wastewater	October 2017	DCN SE06970
Thermal Evaporation Technologies for Treating Power Plant Wastewater	September 2017	DCN SE06971

The Institute of Clean Air Companies (ICAC) is a national trade association of companies that supply air pollution control and monitoring systems, equipment, and services for stationary sources. The EPA met with ICAC to learn more about mercury air pollution control technologies for coal-fired generating units, with a specific focus on the use of halogens and the impacts halogens may have on drinking water plants located downstream of power plants.

#### **2.4.2 Department of Energy**

The EPA used information on steam electric generating plants from DOE’s Energy Information Administration (EIA) Form EIA-860, Annual Electric Generator Report, and Form EIA-923, Power Plant Operations Report. The data collected in Form EIA-860 are associated with the design and operation of generators at plants, and the data collected in Form EIA-923 are associated with the design and operation of the entire plant (U.S. DOE, 2016a and 2016b). The EPA used these data to update the industry profile from the 2015 rule, including commissioning

dates, energy sources, capacity, net generation, operating statuses, planned retirement dates, ownership, and pollution controls of the generating units.

### **2.4.3 Literature and Internet Searches**

The EPA conducted literature and Internet searches to gather information on FGD wastewater treatment technologies, including information on pilot studies, applications in the steam electric power generating industry, and implementation costs and timeline. The EPA also used the Internet searches to identify or confirm reports of planned plant/unit retirements or reports of planned unit conversions to dry or closed-loop recycle ash handling systems. The EPA used industry journals and company press releases obtained from Internet searches to inform the industry profile and process modifications occurring in the industry. Updates made to the industry profile are discussed further in Section 3.1.

The EPA also identified additional FGD wastewater treatment technologies that are being tested and installed. The EPA met with several technology vendors to gather more information on these technologies and examined published research articles describing FGD wastewater treatment technologies at bench-, pilot-, and full-scale levels. The EPA’s evaluation of FGD treatment technologies is further discussed in the preamble.

### **2.4.4 Environmental Groups**

The EPA received information from several environmental groups and other stakeholders following the 2015 rule. In general, these groups provided information about bromide discharges from steam electric power plants, their interaction with drinking water treatment plants, and the associated human health effects. They also noted the advancement in the availability of technological controls for reducing or eliminating pollutant discharges from FGD and bottom ash handling systems. Finally, environmental groups and other stakeholders provided examples of states which, when issuing permits, they believed had not properly considered the “as soon as possible date” for the new, more stringent BAT requirements.

## **2.5 PROTECTION OF CONFIDENTIAL BUSINESS INFORMATION**

Certain data in the rulemaking record have been claimed as confidential business information (CBI). As required by federal regulations at 40 CFR 2, the EPA has taken precautions to prevent the inadvertent disclosure of this CBI. The Agency has withheld CBI from the public docket in the Federal Docket Management System. In addition, the EPA has found it necessary to withhold from disclosure some data not claimed as CBI because the release of these data could indirectly reveal CBI. Where necessary, the EPA has aggregated certain data in the public docket, masked plant identities, or used other strategies to prevent the disclosure of CBI. The Agency’s approach to protecting CBI ensures that the data in the public docket explain the basis for the rule and provide the opportunity for public comment without compromising data confidentiality.

## **2.6 REFERENCES**

1. ERG. 2018. Eastern Research Group, Inc. Memorandum of Site Visit to Harris Treatment Plant. (18 July). DCN SE07225.

2. U.S. DOE. 2016a. U.S. Department of Energy. *Annual Electric Generator Report* (collected via Form EIA-860). Energy Information Administration (EIA). The data files are available online at: <http://www.eia.gov/electricity/data/eia860/index.html>. DCN SE06751.
3. U.S. DOE. 2016b. U.S. Department of Energy. *Power Plant Operations Report* (collected via Form EIA-923). Energy Information Administration (EIA). The data files are available online at: <http://www.eia.gov/electricity/data/eia923/index.html>. DCN SE07241.

## SECTION 3

# CURRENT STATE OF THE STEAM ELECTRIC POWER GENERATING INDUSTRY

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The Agency is proposing revisions to the requirements established in 2015 applicable to FGD wastewater and bottom ash transport water discharged from steam electric power plants. As part of this proposed rule, the EPA updated the industry profile, evaluated changes in wastewater management practices, and assessed impacts from other regulations affecting steam electric power plants. Section 3.1 describes changes to the steam electric power plant population following completion of the 2015 rule analyses. Section 3.2 summarizes current information on discharges of FGD wastewater and bottom ash transport water from steam electric power plants. Section 3.3 describes how other statutes and regulatory actions affecting management of steam electric power plant wastewaters, such as the Coal Combustion Residuals (CCR) rule, are accounted for in the Agency’s updated analyses for the proposed rule.

### 3.1 CHANGES IN THE STEAM ELECTRIC POWER GENERATING INDUSTRY SINCE 2015 RULE

The steam electric power generating industry is dynamic; the Agency recognizes that changes to industry demographics and plant operations occurred following completion of the 2015 rule analyses.<sup>6</sup> Therefore, the EPA collected information on current plant operations and plans for future modifications to augment industry profile data collected for the 2015 rule. This section discusses changes in the number and operating status of coal-fired generating units and updates to wet FGD systems, FGD wastewater treatment, and bottom ash handling systems at steam electric power plants.

The EPA gathered readily available information from public sources, including company announcements and Department of Energy (DOE) Energy Information Administration (EIA) data, to account for the following types of operation changes that have occurred or been announced since August 2014:

- Commissioning of new coal-fired generating units.
- Retirement of coal-fired generating units.<sup>7</sup>
- Fuel conversions of coal-fired generating units from coal to another fuel source, such as natural gas or hydrogen fuel cell.
- Installation of wet FGD systems.
- Modification or upgrade of an FGD wastewater treatment system.

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<sup>6</sup> The EPA accounted for all industry profile changes announced and verified as of August 2014 in the 2015 rule analyses.

<sup>7</sup> For the purposes of this analysis, the EPA accounted for generating units that will be indefinitely removed from service (e.g., idled or mothballed) as retirements. See the preamble for discussion of EPA’s evaluation of coal-fired generating units nearing end of life.



- Installation of, or conversion to, dry, closed-loop recycle, or high recycle rate wet-sludging bottom ash handling system.<sup>8</sup>

The EPA has identified 382 coal-fired generating units at 171 plants with at least one significant change in operation taking place between August 2014 and December 31, 2028 (the date by which proposed revisions to BAT requirements for FGD wastewater and bottom ash transport water would be fully implemented). Table 3-1 presents the count of steam electric generating units and plants, broken out by type of operation change.

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<sup>8</sup> For the purpose of this discussion, dry bottom ash handling systems include all systems that do not generate bottom ash transport water. Consistent with the 2015 rule, the EPA considers a mechanical drag system to be a form of dry bottom ash handling. Although the system uses water in a quench bath to cool bottom ash, water is not used to transport the ash. Closed-loop recycle and high recycle rate systems use water to transport bottom ash and recycle all, or a majority of, the bottom ash transport water back to the bottom ash handling system, respectively.

**Table 3-1. Industry Profile Updates Since August 2014 by Type of Change in Operation**

Change in Operation	Count <sup>a</sup>	
	Generating Units <sup>b</sup>	Power Plants <sup>c</sup>
Commissioning of New Coal-Fired Generating Unit <sup>d</sup>	18	16
Retirement of Coal-Fired Generating Unit	160	78
Fuel Conversion to Non-Coal Fuel Type <sup>e</sup>	43	26
Installation of Wet FGD System	16	8
Modification or Upgrade of FGD Wastewater Treatment System	53	18
Installation or Conversion to Dry, Closed-Loop Recycle, or High Recycle Rate Bottom Ash Handling System	138	61

Source: ERG, 2019a.

Note: EPA's analysis accounted for all changes in operation announced and verified by October 2018. Any changes in operation or planned modifications identified after October 2018 were considered only in a sensitivity analysis. See the memorandum titled "Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule" for additional information on plants identified with industry profile changes and the EPA's sensitivity analysis (ERG, 2019a).

a – Counts are not additive because there may be multiple changes in operation at a single steam electric generating unit or plant (e.g., installation of a dry bottom ash handling system and a wet FGD system).

b – A physical combination of prime movers, including steam turbines and/or combined cycle systems, that utilize steam to drive an electric generator.

c – An establishment that operates a generating unit, whose 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, or 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 Part 423.10).

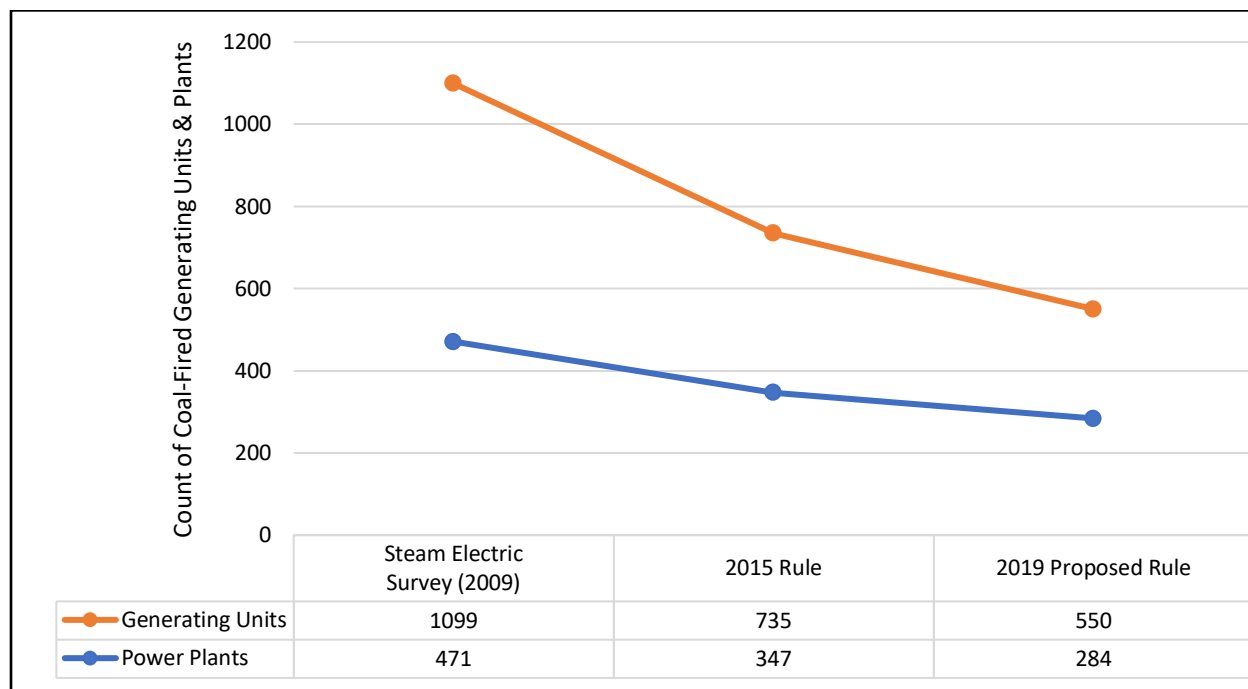
d – Includes seven coal-fired generating units at seven power plants, plus 11 coal-fired generating units commissioned at nine new plants (i.e., plants not accounted for in the 2015 rule analyses).

e – Includes 28 coal-fired generating units at 17 plants converting to natural gas, 1 coal-fired generating unit at one plant converting to hydrogen fuel, 1 coal-fired generating unit at one plant converting to biomass, and 13 coal-fired generating units at 8 plants ceasing to burn coal (announcement does not specify type of fuel conversion).

The EPA updated the industry profile to account for coal-fired generating units subject to the steam electric power generating ELGs that began operation after the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey). The Agency used information from two EIA data collection forms, Form EIA-860 (Annual Electric Generator Report) and Form EIA-923 (Power Plant Operations Report), for the calendar year 2016 to identify generating units commissioned since 2009 (U.S. DOE, 2016a and 2016b). Those active coal-fired generating units that began operating after 2009, operate at least one prime mover utilizing steam, use a form of coal or petroleum coke as the primary energy source, and could be classified as utilities or non-industrial non-utilities were added to the industry profile (unless they were already captured in the 2015 rule analyses). The EPA added new generating units commissioned at both existing power plants (i.e., plants in the 2015 rule population) and new power plants (i.e., those not accounted for in the 2015 rule analyses) to the industry profile for this proposed rule. The EPA collected information on unit operations and wastewater management practices for these generating units from EPA's National Electric Energy Data

System (NEEDS), National Pollutant Discharge Elimination System (NPDES) permits, and regional EPA offices to account for these generating units in corresponding analyses (U.S. EPA, 2018).

The EPA removed coal-fired generating units that will retire or convert fuel type prior to December 31, 2028, from the analyses supporting this proposed rule because they will cease discharging FGD wastewater or bottom ash transport water prior to the date of compliance included with this proposed rule. As shown in Table 3-1, the number of coal-fired generating units and plants expected to retire or convert fuels prior to December 31, 2028 is greater than the number being commissioned, causing an overall decrease in the number of operations. Subsequently, the population of coal-fired generating units and plants decreased to 550 generating units at 284 plants, 25 percent fewer generating units than the 2015 rule population.<sup>9</sup> Figure 3-1 illustrates the change in the number of operating coal-fired steam electric generating units and plants since the Steam Electric Survey and 2015 rule.



Source: ERG, 2019a.

**Figure 3-1. Population of Coal-Fired Generating Units and Plants**

To meet air quality requirements, power plants use a variety of FGD systems to control sulfur dioxide (SO<sub>2</sub>) emissions from flue gas generated in the plant’s boiler. For this proposed rule, the EPA updated the profile to account for wet FGD systems on coal-fired generating units that were not reported in the Steam Electric Survey and to account for upgrades to FGD wastewater treatment systems. The Agency used information available in NEEDS to identify wet FGD systems that began operating after 2009. The EPA collected information on FGD wastewater

<sup>9</sup> The 2015 rule analyses accounted for industry profile changes to be completed before December 31, 2023 (the date that power plants were subject to the established BAT effluent limitations).

generation, management, and treatment for these FGD systems from NPDES permits and regional EPA offices.

Through company announcements and conversations with power plant operators and vendors, the EPA identified plants upgrading or planning to upgrade their bottom ash handling practices or FGD wastewater treatment systems. The EPA collected information on bottom ash handling conversions and FGD wastewater treatment upgrades made at each plant and corresponding generating units, and incorporated changes that would be completed by December 31, 2028 into the industry profile and corresponding technical analyses.

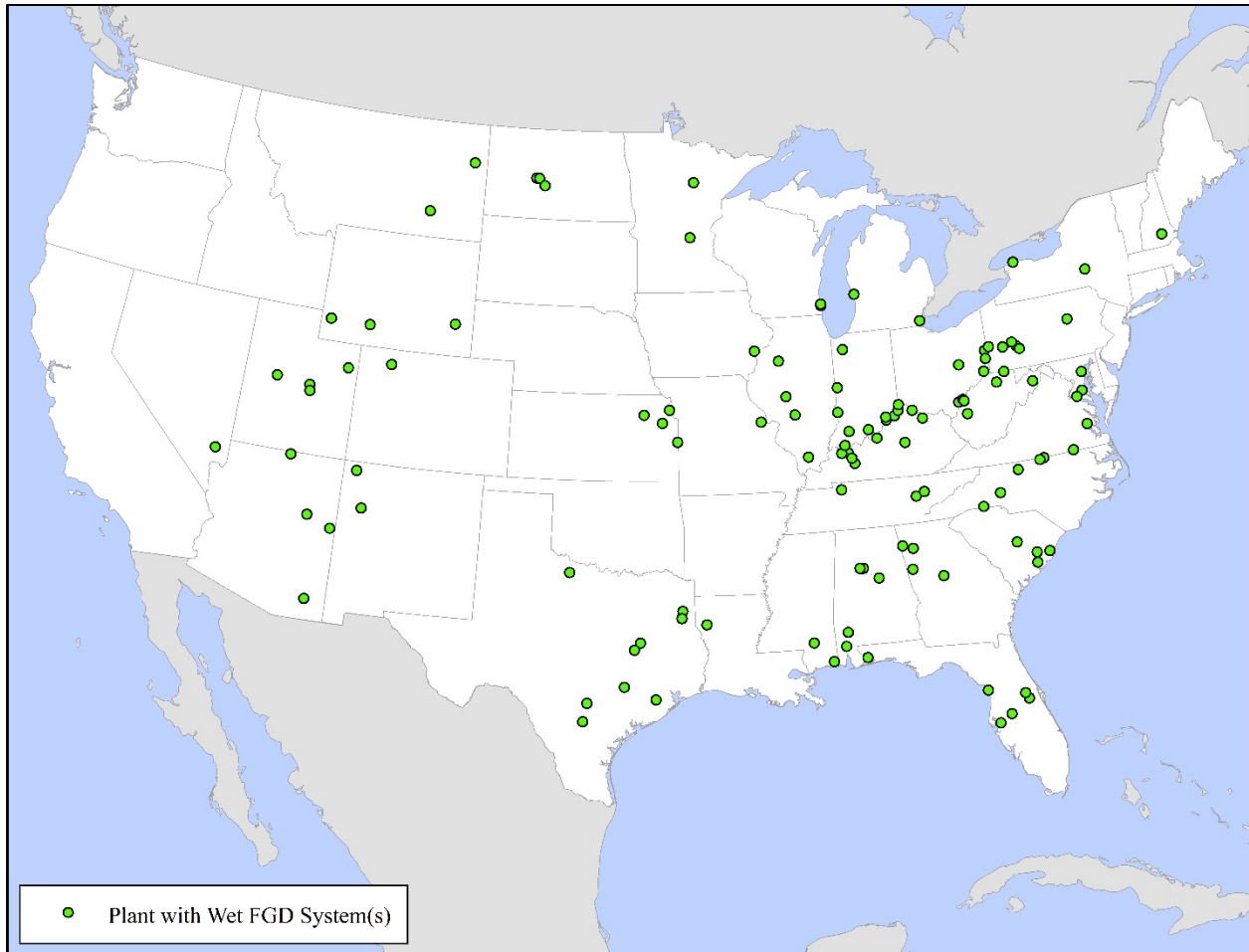
Section 5 and Section 6 describe how the EPA accounted for the changes in operation identified in Table 3-1 in estimating compliance costs, pollutant loadings, and pollutant removals for this proposed rule. Additional information regarding specific coal-fired generating units and plants identified as implementing each type of operation change is discussed in the memorandum titled “Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule” (ERG, 2019a).

### **3.2 CURRENT INFORMATION ON EVALUATED WASTESTREAMS**

The EPA is proposing revised discharge requirements for FGD wastewater and bottom ash transport water generated by steam electric power plants. This section summarizes current information on the generation, characteristics, and discharge of these wastestreams collected by the EPA for this proposed rule.

#### **3.2.1 FGD Wastewater**

As discussed in Section 3.1, the EPA updated the industry profile and corresponding analyses to reflect coal-fired generating units that will retire, convert fuels, or upgrade FGD wastewater treatment prior to December 31, 2028. The EPA also updated the industry profile to reflect wet FGD systems that began operating after the Steam Electric Survey. Of the 550 coal-fired generating units at 284 coal-fired power plants in the updated profile, 270 generating units at 119 plants are serviced by a wet FGD system. The EPA estimates generating units with wet FGD systems have a total wet-scrubbed capacity of 148,000 MW, representing 64 percent of the total industry coal-fired capacity. Figure 3-2 shows the location of plants operating wet FGD systems on at least one coal-fired generating unit in the United States.



Sources: ERG, 2015 and 2019a.

Note: Steam electric power plants shown operate a wet FGD system on at least one generating unit as of June 2018, excluding generating units that will retire or convert fuels by December 31, 2028.

### Figure 3-2. Wet FGD Systems at Steam Electric Power Plants

Although the number of wet FGD systems operated at steam electric power plants has decreased since promulgation of the 2015 rule, current FGD scrubber technologies are the same as those used at the time of the 2015 rule. These wet FGD systems typically use a limestone slurry with forced oxidation and service generating units burning bituminous coal. Often, plants also operate selective catalytic reduction (SCR) systems on these generating units to control nitrogen oxide (NO<sub>x</sub>) emissions.

Following promulgation of the 2015 rule, the EPA collected new information on air pollution control practices at steam electric power plants that may impact characteristics of FGD wastewater. Specifically, the EPA found that steam electric power plants may use bromide or other halogenated compounds to reduce mercury air emissions. While all coal contains at least some naturally-occurring bromide, steam electric power plant operators can augment coal bromide concentrations at various points in the plant operations to enhance mercury oxidation for mercury capture (e.g., directly injecting bromide during combustion; mixing bromide with coal to produce refined coal; and using brominated activated carbon to control air emissions).

Bromide in flue gas at steam electric power plants is captured by wet FGD systems and discharged in FGD wastewater. For this proposed rule, the EPA characterized bromide discharges in FGD wastewater and estimated the corresponding pollutant loadings and removals, as discussed in Section 6.<sup>10</sup>

Since the 2015 rule, steam electric power plants have conducted on-site testing and/or installed additional technologies to treat FGD wastewater. These technologies include, but are not limited to, low residence time reduction (LRTR) biological treatment, high residence time reduction (HRTR) biological treatment, advanced membrane filtration, and thermal evaporative systems. The EPA has identified that approximately ten percent of steam electric power plants with wet scrubbers have technologies in place able to meet the proposed BAT effluent limitations for FGD wastewater, including LRTR, HRTR, and thermal evaporation systems. As described in Section VII of the preamble, a further forty percent of all steam electric power plants with wet scrubbers use FGD wastewater management approaches that eliminate the discharge of FGD wastewater altogether. See Section 4 for more details on these treatment technologies employed by steam electric power plants to treat or reduce FGD wastewater discharges. Table 3-2 summarizes FGD wastewater discharged by the steam electric power generating industry.

**Table 3-2. FGD Wastewater Discharges for the Steam Electric Power Plants**

Number of Plants	Number of Generating Units	FGD Wastewater Discharge Flow Rate			
		Total Daily Discharge Flow Rate (MGD)	Plant Average Daily Discharge Flow Rate (MGD per plant)	Total Annual Discharge Flow Rate (MGY)	Plant Average Annual Discharge Flow Rate (MGY per plant)
70	167	35.3	0.504	12,900	184

Source: ERG, 2019b.

MGY = million gallons per year.

Note: Counts and flow rates presented account for generating units that will retire or convert fuels by December 31, 2028 and wet FGD systems that began operating after the Steam Electric Survey.

### 3.2.2 Bottom Ash Transport Water

Based on the Steam Electric Survey, approximately two-thirds of coal-fired power plants operated wet bottom ash handling systems in 2009. Some plants operating the wet bottom ash handling systems recycled bottom ash transport water from impoundments, dewatering bins, or other handling systems back to the wet-sludging system; however, most bottom ash transport water was discharged to surface water. At the time of the Steam Electric Survey, less than 40 percent of generating units operated dry, closed-loop recycle, or high recycle rate bottom ash handling systems. Because of changes happening in the industry in the years following the Steam Electric Survey, by 2015 more than half of generating units operated or planned to convert to dry, closed-loop recycle, or high recycle rate bottom ash handling systems.

<sup>10</sup> Additional information about sources of bromide at steam electric power plants, impacts of bromide on drinking water treatments, and potential impacts of brominated disinfection byproducts is provided in the *Supplemental Environmental Assessment for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (U.S. EPA, 2019).

As discussed in Section 3.1, the EPA updated the industry profile and corresponding analyses to estimate coal-fired generating units that will retire, convert fuels, or install dry, closed-loop recycle, or high recycle rate bottom ash handling systems prior to December 31, 2028. Since completion of the 2015 rule analyses, more plants have converted or are converting to dry, closed-loop recycle, or high recycle rate bottom ash handling systems, thereby eliminating or minimizing discharge of bottom ash transport water. In addition, based on data from the Steam Electric Survey, generating units commissioned after 2009 are likely to operate dry or closed-loop recycle bottom ash handling systems.<sup>11</sup> Further, the number of coal-fired generating units operating wet sluicing systems has decreased due to plant retirements and fuel conversions. Table 3-3 presents the count and total generating capacity of the generating units operating wet sluicing, closed-loop recycle, high recycle rate, and/or dry bottom ash handling systems. The EPA estimates that more than 75 percent of generating units operate either dry, closed-loop recycle, or high recycle rate bottom ash handling systems.<sup>12</sup> Figure 3-3 illustrates the geographic distribution of plants operating the systems noted in Table 3-3.

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<sup>11</sup> Data from the Steam Electric Survey show that more than 80 percent of generating units built in the 20 years preceding the survey (1989-2009) installed dry bottom ash handling at the time of construction. Since 2009, it has been clear to all power companies and their engineering, procurement, and construction (EPC) firms that the EPA's ELGs and rulemaking efforts would address discharges of bottom ash transport water. Because dry bottom ash technologies are less expensive to operate than wet-sluicing systems and facilitate beneficial use of the bottom ash, it is unlikely that power companies would find it advantageous to install and operate a wet-sluicing bottom ash handling system.

<sup>12</sup> Counts presented in this paragraph and Table 3-3 do not reflect bottom ash handling conversions expected as a result of the CCR rule.

**Table 3-3. Bottom Ash Handling Systems for Coal-Fired Generating Units**

<b>Bottom Ash Handling System</b>	<b>Number of Plants</b>	<b>Number of Generating Units</b>	<b>Nameplate Capacity (MW)</b>
Wet Sluicing System with Limited or No Recycle	62	126	54,800
Wet Sluicing Closed-Loop/High Recycle Rate System	56	140	75,000
Dry Bottom Ash Handling System <sup>b</sup>	173	284	101,000
<b>Total</b>	<b>284 <sup>a</sup></b>	<b>550</b>	<b>230,000</b>

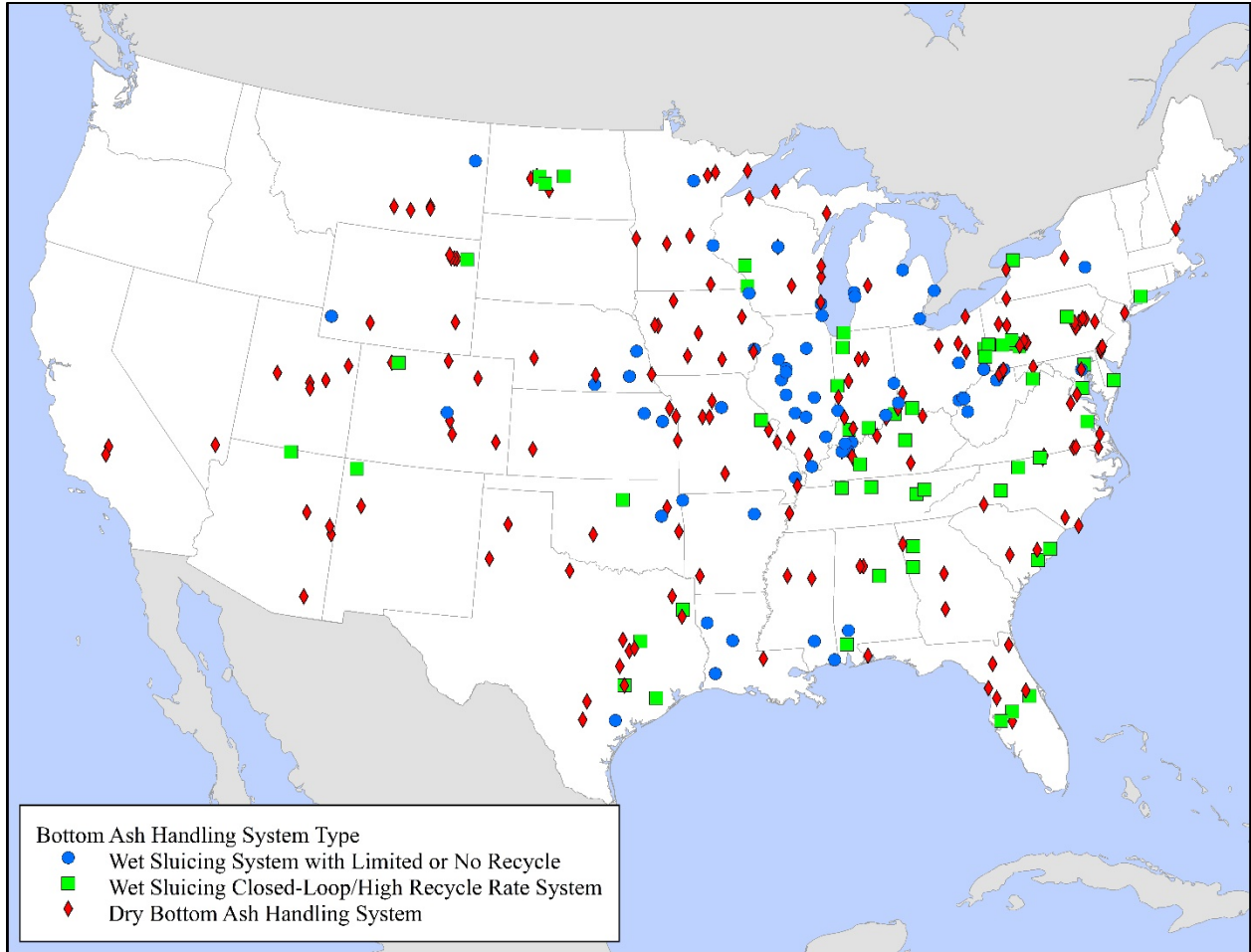
Source: ERG, 2019a.

Note: Counts and capacities presented account for coal-fired generating unit retirements, fuel conversions, and bottom ash handling conversions that will have been completed by December 31, 2028. Values do not reflect additional bottom ash handling system conversions that plants will implement to comply with the CCR rule.

a – Plant counts are not additive because plants may operate multiple types of bottom ash handling systems.

b – The dry bottom ash handling system counts presented in this table reflect conversions identified by the EPA in the Steam Electric Survey and publicly available information since 2009. Where data were available, the EPA tracked the specific types of bottom ash handling conversions, such as mechanical drag systems (MDS) and remote mechanical drag systems (rMDS). However, the EPA identified 63 generating units, corresponding to 25,000 MW at 33 plants, where the data confirmed the plant was not discharging bottom ash transport water but did not confirm the specific type of non-discharging system.





Sources: ERG, 2015 and 2019a.

Note: Excludes power plants that will retire or convert fuels for all coal-fired generating units by December 31, 2028.

**Figure 3-3. Plant-Level Bottom Ash Handling Systems in the Steam Electric Power Generating Industry**

Table 3-4 summarizes bottom ash transport water discharges by the steam electric power generating industry.

**Table 3-4. Bottom Ash Transport Water Discharges for Steam Electric Power Plants**

Number of Plants	Number of Generating Units	Bottom Ash Transport Water Discharge Flow Rate			
		Total Daily Discharge Flow Rate (MGD)	Plant Average Daily Discharge Flow Rate (MGD per plant)	Total Annual Discharge Flow Rate (MGY)	Plant Average Annual Discharge Flow Rate (MGY per plant)
62	126	107	1.73	39,100	631

Source: ERG, 2019c.

Note: Counts and capacities presented account for retirements, fuel conversions, and bottom ash handling conversions at coal-fired generating units that will be complete by December 31, 2028. Values do not reflect bottom ash handling system conversions the EPA expects plants to implement to comply with the CCR rule.

### 3.3 OTHER REGULATIONS ON THE STEAM ELECTRIC POWER GENERATING INDUSTRY

The Agency recognizes that effluent guidelines on steam electric power plants do not exist in isolation – other EPA regulations set requirements for control of pollution emissions, discharges, and other releases from steam electric power plants. For the 2015 rule, the EPA assessed and incorporated impacts from the Clean Power Plan (CPP) and CCR rule into the supporting analyses. Specifically, in the 2015 TDD, the EPA presented the results for the following two scenarios: (1) incorporating expected changes to the industry profile due to the CCR rule, and (2) incorporating expected changes to the industry profile due to both the CCR rule and the CPP.

In 2017, the EPA proposed to repeal the CPP and the regulation was indefinitely stayed by the U.S. Supreme Court. Due to this development, the EPA’s analyses for baseline and the proposed regulatory options do not consider expected profile changes associated with the CPP.<sup>13</sup>

The EPA has continued to account for industry profile changes associated with the CCR rule. The EPA coordinated the requirements of the CCR rule and the 2015 rule to mitigate potential impacts from the overlapping regulatory requirements and to facilitate implementation of engineering, financial, and permitting activities. Based on the CCR rule requirements established in 2015, the EPA expected plants would alter how they operate their CCR surface impoundments, such as by undertaking the following changes:

- Close the disposal surface impoundment and open a new disposal surface impoundment in its place.
- Convert the disposal surface impoundment to a new storage impoundment.
- Close the disposal surface impoundment and convert to dry handling operations.

<sup>13</sup> On August 21, 2018, the EPA proposed the Affordable Clean Energy (ACE) Rule which would establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The ACE Rule would replace the 2015 CPP. The EPA’s costs and pollutant loadings estimates do not reflect any industry profile updates (i.e., retirements) expected from the final ACE Rule since these analyses were completed prior to that rule being finalized, however, a supplemental IPM run including that rule is presented in the preamble and RIA.

- Make no changes to the operation of the disposal surface impoundment.

For the 2015 rule, the EPA developed a methodology to use the yearly probabilistic model output analysis of the CCR rule to predict which of the four potential operational changes could likely occur at each coal-fired power plant that operates a disposal impoundment under the CCR rule. The EPA then updated its population and associated treatment in place to account for the plant-level decisions for operational changes each plant is estimated to make to comply with the CCR rule. Section 9.4.1 of the 2015 TDD describes how the EPA used the classifications to adjust compliance costs, pollutant loadings/removals, and other analyses for each wastestream.

As discussed in Section 1.3, the EPA is proposing revisions to multiple aspects of the 2015 CCR rule. For this proposed ELG, the EPA determined that the plant-specific operational changes estimated in support of the 2015 rule are still valid and useful for this proposed rule. Using the 2015 rule methodology, the EPA expects that 18 plants would convert to mechanical drag or remote mechanical drag bottom ash handling systems because of the CCR rule, and as a result would not incur bottom ash transport water compliance costs attributable to the ELGs.<sup>14</sup> In addition, the EPA estimates 8 plants would modify their FGD wastewater treatment because of the CCR rule and, as a result, their costs to comply with the ELGs would be reduced.

Section 5 and Section 6 describe how the EPA accounted for CCR rule impacts in estimating compliance costs, pollutant loadings, and pollutant removals for this proposed rule. The EPA also conducted a sensitivity analysis using company-posted liner and leak status data, required as part of the CCR rule, to account for additional surface impoundment closures and corresponding changes in operation, discussed in the memorandum titled “Sensitivity Analysis for Estimating the Impacts of the Proposed Amendments to the CCR Rule” (ERG, 2019d).

### 3.4 REFERENCES

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2. ERG. 2019a. Eastern Research Group, Inc. Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule. (July 31). DCN SE07207.
3. ERG. 2019b. Eastern Research Group, Inc. FGD Loads Database. (July 18). DCN SE07103.
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<sup>14</sup> Plants that install rMDS to comply with the CCR rule may incur costs to install a reverse osmosis system to treat a slipstream of the recirculating bottom ash transport water, as a way to remove dissolved solids and facilitate long-term operation of the system as a closed loop to comply with the bottom ash zero discharge requirements of the 2015 rule (i.e., baseline). There are other approaches that can also be used to remove dissolved solids from the bottom ash system without using reverse osmosis treatment, such as using the transport water as makeup water for the FGD system. Dissolved solids will also be removed from the system along with the bottom ash, which is wet as it is removed from the rMDS. As appropriate, the EPA will update the compliance cost estimates for these plants in future analyses.

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## SECTION 4 TREATMENT TECHNOLOGIES AND WASTEWATER MANAGEMENT PRACTICES

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This section provides an overview of treatment technologies and wastewater management practices at steam electric power plants for flue gas desulfurization (FGD) wastewater and bottom ash handling wastewater. All technologies evaluated as part of the 2015 rule are still being used in the industry; see the 2015 TDD for a full description of these technologies. This section focuses primarily on technologies identified for the treatment of FGD wastewater and bottom ash handling wastewater since the 2015 rule.

### 4.1 FGD WASTEWATER TREATMENT TECHNOLOGIES

In promulgating the 2015 rule, the EPA identified surface impoundments as the most prevalent treatment technology for plants discharging FGD wastewater, and chemical precipitation (i.e., tank-based systems designed primarily to remove suspended solids) as the second most common treatment technology. These technologies are described in the 2015 TDD. While approximately half of the industry discharging FGD wastewater still relies on these technologies, with the most prevalent now being chemical precipitation, more advanced treatment technologies have become more common since the 2015 rule. Several plants have upgraded their FGD wastewater treatment by installing either biological or thermal treatment systems. The biological systems installed have been either the high residence time anoxic/anaerobic biological technology—used as the basis for the FGD BAT limitations in the 2015 rule— or a similar process that targets removal of the same pollutants in a smaller system with a shorter hydraulic residence time in the bioreactor. Thermal systems installed have been either a spray dryer evaporator or the falling-film evaporator design, which was used as the basis for the NSPS limitations and the BAT Voluntary Incentive Program in the 2015 rule. See the 2015 TDD for a description of thermal treatment technologies and other zero discharge technologies.

The EPA also identified several additional treatment technologies that were developed (or adapted from other industry sectors) in recent years and have been tested at some power plants. This section provides a summary of the treatment technologies evaluated as part of this proposal.

- Biological treatment.
- Zero-valent iron (ZVI).
- Membrane filtration.
- Thermal treatment.
- Solidification.
- Other pilot-scale tested technologies.

#### 4.1.1 Biological Treatment

Several types of biological treatment systems are currently used to treat FGD wastewater. These biological technologies include:

- Anoxic/anaerobic biological treatment systems, designed to remove selenium and other pollutants.
- Sequencing batch reactors, which alternate between aerobic and anaerobic stages to remove nitrates and ammonia.
- Aerobic bioreactors for reducing BOD.

These biological treatment processes are typically operated downstream of a chemical precipitation system or a solids removal system (e.g., clarifier, surface impoundment).

The anoxic/anaerobic biological technology is designed to remove selenium, nitrate-nitrite, mercury and other pollutants. This process uses an anoxic/anaerobic fixed-film bioreactor that consists of an activated carbon bed or other permanent porous substrate that is inoculated with naturally occurring, beneficial microorganisms. The microorganisms grow within the substrate, creating a fixed film that retains the microorganisms and precipitated solids within the bioreactor. The system uses microorganisms chosen specifically for use in FGD systems because of their hardiness in the extreme water chemistry, as well as selenium respiration and reduction.

The microorganisms reduce the selenate and selenite to elemental selenium, which forms nanospheres that adhere to the cell walls of the microorganisms. The microorganisms can also reduce other metals, including arsenic, cadmium, nickel, and mercury, by forming metal sulfides within the system (Pickett, 2006).

#### *High Residence Time Reduction Biological Treatment*

High residence time reduction (HRTR) biological treatment systems consist of chemical precipitation followed by an anoxic/anaerobic fixed-film bioreactor. This technology was the basis for effluent limitations established by the 2015 rule. Plants usually employ multiple bioreactors to provide the necessary residence time to achieve the specified removals. This technology, as it has been applied at power plants for treating FGD wastewater, uses equipment that is large enough to provide for hydraulic residence times in the bioreactor that are typically on the order of 10 to 16 hours.

The bioreactor is designed for plug flow to ensure that the feed water is evenly distributed and has maximum contact with the microorganisms in the fixed film. As wastewater passes through the bioreactor, it goes through zones operating at have differing oxidation-reduction potential (ORP). Plants operate the bioreactors to achieve a negative ORP, which provides the optimal environment to reduce selenium to its elemental form. The top part of the bioreactor, where the plant feeds the wastewater, is aerobic with a positive ORP, which allows nitrification and organic carbon oxidation to occur. As the wastewater moves down through the bioreactor, it enters an anoxic zone (negative ORP) where denitrification and chemical reduction of selenium (both selenate and selenite) occur (Pickett, 2006; Sonstegard, 2010).

The HRTR biological technology is described in detail in Section 7.1.3 of the 2015 TDD. The EPA identified at least five plants that have operated this system at full-scale in the steam electric power generating industry. One of these plants no longer operates HRTR and has installed an

evaporation system. A number of other plants have conducted pilot tests of this technology in preparation for making upgrades to comply with the 2015 Rule requirements.

#### *Low Residence Time Reduction Biological Treatment*

In the years since the EPA first identified the HRTR biological technology during the development of the 2015 rule, power companies and technology vendors have worked to develop processes that target removals of the same pollutants in a smaller system with a lower hydraulic residence time in the bioreactor. These technologies, described here as low residence time reduction (LRTR) technologies, use some of the same treatment mechanisms (e.g., anoxic/anaerobic fixed-film bioreactors) to remove selenium, nitrate, nitrite, and other pollutants in less time, typically on the order of 1 to 4 hours hydraulic residence in the bioreactor.

One LRTR technology includes a chemical precipitation pretreatment system followed by an anoxic, upflow bioreactor followed by a second-stage downflow biofilter. The shorter hydraulic residence time of this system requires smaller bioreactors and other equipment, resulting in a treatment system that is physically much smaller than the HRTR system. Data provided by the power industry and an independent research organization show that the LRTR system performance is comparable to that achieved by HRTR technology. Much of the LRTR bioreactor and related equipment is fabricated off-site as modular components. Modular, prefabricated, skid-mounted components, coupled with the smaller physical size of the system, results in lower installation costs and shorter installation times, relative to HRTR systems, which are usually constructed on-site. At least four coal fired steam electric power plants have installed full-scale LRTR systems currently being used to treat FGD wastewater and this technology has been pilot tested using FGD wastewater at more than a dozen steam electric power plants since 2012.

Another LRTR technology, fluidized bed reactors (FBRs), has historically been used to treat selenium in mining wastewaters; however, is now being tested on FGD wastewater. The FBR system is also an anoxic/anaerobic fixed-film bioreactor design. It relies on an attached growth process, in which microbial growth forms on granular activated carbon media that is fluidized by an upflow of FGD wastewater through the suspended carbon media. The EPA identified 12 pilot studies of the FBR technology for selenium removal in mining, refining/petrochemical, and steam electric industries. Three of these pilot-study tests involved FGD wastewater.

#### **4.1.2 Zero Valent Iron**

ZVI, in combination with other systems such as chemical and physical treatment, can be used to target specific inorganics, including selenium, arsenic, nitrate, and mercury in FGD wastewater.

The technology entails mixing influent wastewater with ZVI (iron in its elemental form), which reacts with oxyanions, metal cations, and some organic molecules in wastewater. ZVI causes a reduction reaction of these pollutants, after which the pollutants are immobilized through surface adsorption onto iron oxide coated on the ZVI or generated from oxidation of elemental iron. The coated, or spent, ZVI, is separated from the wastewater with a clarifier. Spent ZVI can be disposed of in a non-hazardous landfill. The quantity of ZVI required and number of reaction vessels can be varied based on the composition and amount of wastewater being treated.

Treatment configurations for FGD wastewater would typically include chemical precipitation followed by ZVI treatment and may also include pretreatment to partially reduce influent nitrate concentrations at plants with high nitrate levels in the FGD purge.<sup>15</sup> The purpose of the nitrate pretreatment is to reduce the consumption rate of the ZVI media, which reacts with both the nitrates and selenium in the wastewater. A potential application for FGD wastewater would employ four reactors in series. This configuration provides extra treatment capacity that allows the operator to bypass and isolate individual units whenever maintenance is needed without having to shut down the entire treatment system. This configuration, by including an extra ZVI reactor in the treatment train, also provides additional polishing treatment capability that can be appealing for some plants.

The EPA identified seven completed pilot-scale studies of ZVI used for FGD wastewater treatment.<sup>16</sup> At least four additional pilot-scale studies for FGD wastewater treatment at power plants were in the planning stage for power plants located in the eastern United States, as of 2016. The data in the record from a subset of these pilots indicates that the combination of chemical precipitation and ZVI technology, along with nitrate pretreatment, where warranted, can produce effluent quality comparable to chemical precipitation followed by LRTR (CP+LRTR) and chemical precipitation followed by HRTR (CP+HRTR) technologies.

#### **4.1.3 Membrane Filtration**

These systems are specifically designed to treat high TDS and TSS wastestreams, using thin semi-permeable filters or film membranes. Membrane filtration is a treatment process used for the removal of dissolved materials from industrial wastewater and includes microfiltration, ultrafiltration, nanofiltration, forward osmosis, and reverse osmosis (RO) membrane systems. The size of the particle that can pass through the membrane is determined by the membrane pore size, with RO membranes being the most restrictive and microfiltration being the least restrictive. Most membrane filtration systems use pumps to apply pressure to the solution from one side of the semi-permeable membrane to force wastewater through the membrane, leaving behind dissolved solids retained (“rejected”) by the membrane and a portion of the water. The rate that water passes through the membrane depends on the operating pressure, concentration of dissolved materials, and temperature, as well as the permeability of the membrane.

Forward osmosis (FO) uses a semi-permeable membrane and differences in osmotic pressures to achieve separation. These FO systems use a draw solution at a higher concentration than the feed, (e.g., FGD wastewater) to induce a net flow of water through the membrane. This results in

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<sup>15</sup> FGD purge with nitrate/nitrite concentrations at or above 100 mg/L typically require additional denitrification before ZVI treatment.

<sup>16</sup> The EPA has also observed ZVI technology in treating ash transport water during impoundment dewatering. In this application, the impoundment water was first treated by reverse osmosis membrane filtration, and the membrane reject stream was sent to ZVI reactors for treatment. The membrane permeate and ZVI effluent streams were both discharged by the plant to surface waters. Although this application was not treating FGD wastewater, many of the pollutants present in FGD wastewater are also present in ash impoundments and these pollutants were effectively removed by the ZVI process (ERG, 2019). A similar treatment process has been suggested for FGD wastewater, whereby the treatment train would be configured as chemical precipitation followed by reverse osmosis membrane filtration, and the membrane reject stream would be sent to a ZVI stage consisting of three reactors in series. Similar to the treatment system for the impoundment, the RO permeate and ZVI effluent would be discharged (unless the RO permeate was reused within the plant).



diluting the draw solution and concentrating the feed stream. This technology is different from RO, which utilizes hydraulic pressure to drive separation. FO technology is typically better suited for high-fouling streams than traditional RO because external pumps are not needed to drive treatment.

Membrane systems separate feed wastewater into two product streams: a permeate stream, which is the “clean” water that has passed through the membrane, and the concentrate stream, which is the water (or brine) rejected by the membrane. The percentage of membrane system feed that emerges from the system as permeate is known as the water recovery. Depending on wastewater characteristics, membrane systems may require pretreatment to remove excess TSS and organics to prevent scaling and fouling in industrial applications. Fouling occurs when either dissolved or suspended solids deposit onto a membrane surface or a microbial biofilm grows on the membrane surface and degrades its overall performance.

As part of the reconsideration of the 2015 rule, the Agency identified and further reviewed several new uses of membrane filtration technologies currently being studied in the industry. Depending on the FGD wastewater characteristics, these membrane systems typically include nanofiltration membranes, RO, or FO. To reduce fouling, membrane filtration systems have been designed with vortex generating blades or vibratory movement. Other technologies focus on a microfiltration pretreatment step that targets scale-forming ions where FGD wastewater characteristics indicate potential fouling.

Incorporating membranes into existing chemical precipitation systems can improve the efficiency of the membrane system and may help lower the capital and operation and maintenance costs. Many of the systems piloted for FGD wastewater to date have included some type of pretreatment to reduce TSS before entering the membrane system (e.g., surface impoundment, chemical precipitation). Membrane systems can also be configured with a post-processing RO system to further remove pollutants from the permeate. Additionally, membrane systems can be used in combination with other technologies (e.g., thermal evaporation) to treat FGD wastewater or achieve zero discharge.

Permeate streams from these systems can be reused within the plant or discharged, while reject streams (i.e., concentrated brine) would be disposed of in a landfill using solidification (See Section 4.1.5) or another process, such as thermal system treatment.

Membrane filtration has been piloted for FGD wastewater treatment at some plants in the steam electric power generating industry. The EPA spoke with several vendors that have tested the technology in the past and are actively pursuing additional testing. The EPA also identified three plants in China that have installed membrane filtration systems to treat FGD wastewater. Two of the plants employ pretreatment and a combination of RO and forward osmosis. The EPA does not have information on how the brine is handled at these two plants. The third plant operates pretreatment followed by nanofiltration and RO. At this plant, the brine undergoes thermal treatment to produce a crystallized salt which is sold for industrial use.

#### 4.1.4 Thermal Treatment

Thermal technologies include a variety of treatment technologies that use heat to evaporate water and concentrate solids and other contaminants. Some of these systems can be operated to achieve full evaporation of all liquid, resulting in only a solid product, or achieve partial evaporation of liquid. These thermal technologies can also be used in combination with other technologies to treat FGD wastewater or achieve zero discharge.

One type of thermal treatment uses brine concentrators followed by crystallizers, which generates a distillate stream and solid by-product that can be disposed of in a landfill. This treatment configuration was evaluated as part of the 2015 rule, see Section 7.1.4 of the 2015 TDD for a detailed description of this treatment configuration. As part of this proposed rule, the EPA identified several additional thermal technologies that rely on this same premise, i.e., using heat to evaporate water and concentrate contaminants.

Spray dryers are an example of a technology that is being applied to FGD wastewater treatment. These systems utilize a hot gas stream to quickly evaporate liquid resulting in a dry solid or powder. For FGD applications, a slipstream of hot flue gas from upstream of the air heater can be used to evaporate FGD wastewater in a vessel. The FGD solids are carried along with the flue gas slipstream which is recombined with the main flue gas stream. All solids are then removed with the fly ash in the main particulate control equipment (e.g., electrostatic precipitator or fabric filter) and disposed of in a landfill. In cases where fly ash is marketable, and contamination is a concern, a separate particulate control system can be operated on the flue gas slipstream to capture FGD solids alone. While these spray dryer systems can be an efficient treatment of FGD wastewater, retrofitting these systems into existing plants could be difficult.

One vendor has developed a proprietary technology that combines concepts of the brine concentrator and spray dryer to achieve zero discharge without a crystallizer. The system, referred to as an adiabatic evaporator technology, injects wastewater into a hot feed gas stream to form water vapor and concentrated wastewater. The air-water mixture is separated in an entrainment separator. Water vapor is exhausted, and wastewater is sent to a solid-liquid separator. The concentrated wastewater is recycled and sent back through the system while the solids can be landfilled. An alternative configuration would be to not recycle the concentrated wastewater and instead reject it from the system. This reject stream could be solidified, by mixing with fly ash, and landfilled. Pretreatment of FGD wastewater is not required but, for situations where TSS exceeds 5 percent it maybe be cost-effective to operate a clarifier upstream of the evaporator to decrease solids. This system was operated at full-scale at a coal-fired power plant for three years. FGD wastewater was pretreated using a clarifier then sent to the adiabatic evaporator where 100 percent of the FGD wastewater was evaporated and solids deposited in a landfill. Because propane was used as the heat source, operation and maintenance costs proved to be too costly and the system was replaced.

Another vendor has developed a modular brine concentration technology. This system uses thermal energy to heat FGD wastewater and facilitate evaporation. As the wastewater boils, steam is collected, compressed, and directed into proprietary technology that allows the heat to transfer from the steam to the concentrated wastewater stream; causing it to become superheated. As water evaporates from the superheated wastewater, the steam is collected and condensed.

This distillate stream can be reused in the plant as cooling tower make up or within the FGD scrubber. The concentrated wastewater, referred to as brine, is discharged from the system once it reaches a set TDS concentration (not to exceed 200,000 parts per million (ppm)). This brine stream is treated through hydrocyclones to remove suspended solids. The resulting liquid can be solidified and landfilled. Pretreatment of FGD wastewater is only required when TSS concentrations exceed 30 ppm. Chemicals are added to maintain pH and inhibit crystal and scale formation. This technology has been pilot tested at four coal-fired power plants in 2015 and 2017.

#### **4.1.5 Solidification**

Solidification is a technology option that may prevent FGD wastewater discharge. Solidification is process by which temperature and chemical reactions are used to bond materials together. This process can also be referred to as fixation. This technology has been used by plants operating inhibited oxidation scrubber systems, where byproducts from the scrubber are mixed with fly ash and lime to produce a non-hazardous landfillable material. This same approach is being tested with pretreated FGD wastewater by mixing concentrated FGD wastewater, from membrane systems or thermal systems that only achieve partial evaporation. The concentrated FGD wastewater is mixed with various combinations of fly ash, hydrated lime, sand, and/or Portland cement to encapsulate contaminants. Tests of these materials have confirmed that the solids generated meet solid waste leaching requirements (toxicity characteristic leaching procedure (TCLP), and other local landfill regulations (Pastore and Martin, 2017; Martin, 2019).

#### **4.1.6 Other Technologies Under Investigation**

The EPA also identified several emerging technologies for FGD wastewater treatment. The EPA reviewed EPRI reports, industry sources, and published research articles describing alternative FGD wastewater treatment technologies being evaluated to date and identified several that are in the early stages of development. While the technologies described in this section have not been implemented at full-scale levels in the steam electric power generating industry to date, these technologies have been evaluated in pilot-scale testing for FGD wastewater at power plants.

##### *Electrodialysis Reversal and Reverse Osmosis Technology*

Electrodialysis reversal (EDR) is a technology that uses an electric current to migrate dissolved ions through stacks of alternating cationic and anionic ion exchange membranes. While this process is typically used to desalinate water, it is now being used to treat FGD wastewater in pilot-scale tests. The EDR technology results in three wastestreams, one permeate stream and two wastestreams. The permeate stream can be further treated with a RO system to remove additional metals and conventional pollutants. Reject from the RO is recycled through the EDR process while the RO permeate can be reused as cooling tower make up or within the FGD scrubber. The two wastestreams, one a calcium chloride rich brine stream and one a sodium sulfate rich brine stream, can be recombined to produce gypsum ( $\text{CaSO}_4$ ), solidified, or treated using a crystallizer. This system has been bench-scale tested using FGD wastewater and pilot-scale tested at least once, in 2017.

### *Closed-Loop Mechanical Vapor Recompression*

Mechanical vapor compression is a technology that can be used to treat FGD wastewater, as well as other wastestreams, and was evaluated as a technology option under the 2015 rule. A vendor has come up with a proprietary application of this technology that operates as a closed-loop system. The system uses four interconnecting loops to pre-heat process wastewater, concentrate and crystallize wastewater using turbulent flow heat exchangers, and recover and condense steam to produce a clean distillate stream. This technology is currently used in full-scale operations in metal working and manufacturing applications. EPRI and the technology vendor operated a pilot test of the system to treat FGD wastewater from power plants at the Plant Bowen Water Research Center in 2015 (EPRI, 2015).

### *Distillation-Based Thermal Transfer System*

One vendor has developed a proprietary combination of technologies that operate as one thermally-balanced system to treat industrial wastewater streams. This technology combines degassing, distillation, and demisting to heat industrial wastewater streams, generating a clean water stream and gray water or brine stream. The gray water or brine stream is a concentrated wastewater stream that either flash crystallizes upon discharge or crystallizes upon cooling, resulting in zero liquid discharge. Energy required to drive degassing and distillation can come from steam, natural gas, flue gas, waste heat, or other renewable sources such as solar or geothermal, depending on availability. The vendor has conducted bench scale testing using FGD wastewater and is currently pursuing pilot testing opportunities with industry trade groups and individual plants. This technology has also been tested on produced water from the oil and gas industry and cooling tower blowdown.

## **4.2 BOTTOM ASH HANDLING SYSTEMS AND TRANSPORT WATER MANAGEMENT AND TREATMENT TECHNOLOGIES**

As part of this reconsideration, the EPA reviewed bottom ash handling systems designed to minimize or eliminate the discharge of bottom ash transport water that are operated by coal-fired power plants or marketed by bottom ash handling vendors. As part of the 2015 rule, the EPA determined that almost 60 percent of the coal-fired power plants in the industry operate wet-slucicing systems on one or more of their coal-fired generating units. As described in Section 3, many plants have installed, or are installing, bottom ash handling systems that minimize or eliminate the discharge of bottom ash transport water. Specifically, the EPA now estimates that just 22 percent of coal-fired power plants in the industry operate wet sluicing systems (see the 2015 TDD for more details on wet sluicing systems). The bottom ash handling technologies evaluated by the EPA are listed below

- Mechanical Drag System.
- Remote Mechanical Drag System.
- Dry Mechanical Conveyor.
- Dry Vacuum or Pressure System.
- Submerged Grinder Conveyor.

#### **4.2.1 Mechanical Drag System**

A mechanical drag system collects bottom ash from the bottom of the boiler through a transition chute and sends it into a water-filled trough. The water bath in the trough quenches the hot bottom ash as it falls from the boiler and seals the boiler gases. The drag system uses a parallel pair of chains attached with crossbars at regular intervals. In a continuous loop, the chains move along the bottom of the water bath, dragging the bottom ash toward the far end of the bath, then begin moving up an incline, dewatering the bottom ash by gravity and draining the water back to the trough. Because the bottom ash falls directly into the water bath from the bottom of the boiler and the drag chain moves constantly on a loop, bottom ash removal is continuous. The dewatered bottom ash is often conveyed to a nearby collection area, such as a small bunker outside the boiler building, from which it is loaded onto trucks and either sold or transported to a landfill. See Section 7.3.3 of the 2015 TDD for more specific system details.

The mechanical drag system does generate some wastewater (i.e., residual water that collects in the storage area as the bottom ash continues to dewater). This wastewater is either recycled back to the quench water bath or directed to the low volume waste system. This wastewater is not bottom ash transport water because the transport mechanism is the drag chain, not the water.<sup>17</sup>

This system may not be suitable for all boiler configurations and may be difficult to install in situations where there is limited space below the boiler. These systems are not able to combine and collect bottom ash from multiple boilers and most installations require a straight exit from the boiler to the outside of the building. In addition, these systems may be susceptible to maintenance outages due to bottom ash fragments falling directly onto the drag chain.

#### **4.2.2 Remote Mechanical Drag System**

Remote mechanical drag systems collect bottom ash using the same operations and equipment as wet-slucing systems at the bottom of the boiler. However, instead of sluicing the bottom ash directly to an impoundment, the plant pumps the bottom ash transport water to a remote mechanical drag system. This type of system has the same configuration as a mechanical drag system, but with additional dewatering equipment in the trough. Also, it does not operate under the boiler, but rather in an open space on the plant property. See Section 7.3.4 in the 2015 TDD for more specific system design details.

Plants converting their current bottom ash handling systems can use this system if space or other restrictions limit the changes that can be made to the bottom of the boiler. Currently, over 50 coal-fired power plants have installed, or are planning to install, remote mechanical drag systems to handle bottom ash.

Because of the chemical properties of bottom ash transport water, some plants may have to treat the overflow (or a slipstream of the overflow) before recycling, to prevent scaling and fouling in the system. Plants that require treatment to achieve complete recycling of bottom ash transport

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<sup>17</sup> The mechanical drag system does not need to operate as a closed-loop system because it does not use water as the transport mechanism to remove the bottom ash from the boiler; the conveyor is the transport mechanism. Therefore, any water leaving with the bottom ash does not fall under the definition of “bottom ash transport water,” but rather, is a low volume waste.

water could install a pH adjustment system or an RO membrane (as described in EPA’s cost methodology in Section 5).

Similar to the mechanical drag system, the drag chain conveys the ash to a collection area and the plant then sells or disposes of it in a landfill. There is also an opportunity for multiple unit synergies and redundancy with remote mechanical drag systems because they are not operating directly underneath the boiler. This system requires less maintenance compared to the mechanical drag system because the bottom ash particles entering the system have already been through the grinder prior to sluicing.

#### **4.2.3 Dry Mechanical Conveyor**

Dry mechanical conveyor systems operate similarly to a mechanical drag system, but instead of collecting the bottom ash in a water bath, it is collected directly onto a dry conveyor. The system introduces ambient air countercurrent to the direction of the bottom ash using the negative pressure in the furnace. Adding more air activates reburning, which reduces unburned carbon and adds thermal energy to the steam electric power generating process in the boiler, making the boiler more efficient. The dry conveyor then takes the bottom ash to an intermediate storage destination. The modular design of the system allows it to be retrofitted into plants with space or headroom limitations and a wide range of steam electric generating unit capacities (from 5 MW to 1,000 MW). See Section 7.3.5 of the 2015 TDD for more details.

#### **4.2.4 Dry Vacuum or Pressure System**

Dry vacuum or pressure bottom ash handling systems transport bottom ash from the bottom of the boiler into a dry hopper, without using any water. The system percolates air into the hopper to cool the ash, combust additional unburned carbon, and increase the heat recovery to the boiler. Periodically, the grid doors at the bottom of the hopper open to allow the bottom ash to pass into a crusher. The system then conveys the crushed bottom ash by vacuum or pressure to an intermediate storage location. See Section 7.3.6 of the 2015 TDD for more details.

Dry vacuum or pressure systems eliminate water requirements and improve heat recovery and boiler efficiency. These systems are also less complicated to retrofit because there are fewer structural limitations (e.g., headspace requirements below the boiler) and the systems can be installed to collect bottom ash from multiple boilers and send it to one intermediate storage location.

#### **4.2.5 Submerged Grind Conveyor**

Submerged grind conveyors collect bottom ash from the bottom of the boiler. The system uses existing equipment—bottom ash hoppers or slag tanks, the bottom ash gate, clinker grinders, and a transfer enclosure—to remove bottom ash from the hopper continuously. From the bottom of the boiler, bottom ash falls into the water impounded hopper or slag tank. It is then directed to the existing grinders to be ground into smaller pieces and is then transferred to a water-tight chain and flight conveyor system. Similar to a mechanical drag system, except for the water-tight design, a drag chain continuously carries and dewateres bottom ash up an incline, away from the boiler. The dewatered bottom ash is transferred to a second conveyor, which transports it to a

bottom ash silo. The system can be designed to avoid existing structures or with equipment to transfer the bottom ash out of the boiler house.

Using the existing transfer enclosures, the systems can be isolated from the hopper to perform maintenance while the generating unit remains on-line (made possible by the bottom ash storage capacity of the hopper). The system also has low auxiliary power requirements and maintenance costs due to the mechanical transfer conveyor design. In addition, because the system reuses the wet sluicing equipment, installation and outage times are shorter compared to other under-the-boiler bottom ash handling systems.

The EPA is aware of two plants that have installed and are operating this type of bottom ash handling system in the United States.

### 4.3 REFERENCES

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## SECTION 5 ENGINEERING COSTS

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This section presents EPA’s methodology for estimating capital costs and operation and maintenance (O&M) costs for steam electric power plants to comply with regulatory options being considered for discharges of flue gas desulfurization (FGD) wastewater and bottom ash transport water. The BAT/PSES regulatory options described in the preamble comprise various combinations of treatment technologies evaluated for controlling pollutants in each of the wastestreams. The regulations promulgated by the 2015 rule remain codified in 40 CFR Part 423; the costs associated with the regulatory options for this proposed rulemaking are the incremental changes in costs (additional costs or cost savings) relative to the costs for plants to meet the requirements of the 2015 rule. As such, the EPA is presenting cost estimates for baseline and post-compliance, defined as follows:

- *Baseline Compliance Costs.* The costs for plants to comply with the 2015 rule requirements for FGD wastewater and bottom ash transport water, relative to the conditions currently present or planned at each plant. For those plants where upgrades would be needed to meet the requirements established by the 2015 rule, the EPA estimated baseline costs of installing the technologies selected as the BAT/PSES basis of that rule (i.e., chemical precipitation followed by high residence time reduction (CP+HRTR) for FGD wastewater; dry or closed-loop handling for bottom ash).
- *Post-Compliance Costs.* These are the costs for plants to comply with effluent limitations based on the technologies considered in this proposed rule for FGD wastewater and bottom ash transport water, relative to the conditions currently present or planned at each plant. For those plants where upgrades would be needed, the EPA estimated post-compliance costs based on plants installing the technologies that would be the basis for BAT/PSES (e.g., chemical precipitation followed by low residence time reduction (CP+LRTR) for FGD wastewater; High Recycle Rate for bottom ash transport water).
- *Incremental Costs.* The incremental costs are the difference between the baseline compliance costs and post-compliance costs for each regulatory option. Since the 2015 rule is currently codified in the Code of Federal Regulations, the incremental costs reflect the cost savings (or increases) estimated to result from modifying the requirements established by the 2015 rule.

Section 5.1 describes the general methodology for estimating incremental compliance costs. Sections 5.2 and 5.3 describe the methodologies the EPA used to estimate costs to achieve the proposed limitations and standards based on the technology options selected. These sections also present information on the specific cost elements included in EPA’s methodology. Finally, Section 5.4 summarizes national engineering costs associated with the considered regulatory options.



## 5.1 GENERAL METHODOLOGY FOR ESTIMATING INCREMENTAL COMPLIANCE COSTS

For FGD wastewater and bottom ash transport water, the EPA assessed the operational practices and treatment system components in place at each plant, identified equipment and process changes that each plant would likely make to meet the proposed effluent limitations guidelines and standards (ELGs), and estimated the incremental cost or savings to meet each of the regulatory options considered for the proposed rule, relative to the costs to comply with the 2015 rule.

While plants are not required to implement the specific technologies that form the basis for the options considered for the proposed rule, the EPA based its calculations on plants implementing these technologies to estimate incremental compliance costs incurred by the industry. The EPA summed plant-specific costs to represent industry-wide compliance costs for each regulatory option considered for the proposed rule.

The EPA estimated compliance costs associated with each regulatory option from data collected through responses to the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (hereinafter Steam Electric Survey), site visits, sampling episodes, and from individual power plants and equipment vendors. Data sources include the data used during the development of the 2015 rule, as well as additional cost information collected from industry and technology vendors (see Section 2).

The EPA's cost estimates include the following components:

- Capital costs (one-time costs).
- Annual O&M costs (which are incurred every year).
- Other one-time or recurring costs.

Capital costs comprise the direct and indirect costs associated with purchasing, delivering, and installing pollution control technologies. Capital cost elements are specific to the industry and commonly include purchased equipment and freight, equipment installation, buildings, site preparation, engineering costs, construction expenses, contractor's fees, and contingencies. Annual O&M costs comprise all costs related to operating and maintaining the pollution control technologies for a period of one year. O&M costs are also specific to the industry and commonly include costs associated with operating labor, maintenance labor, maintenance materials (routine replacement of equipment due to wear and tear), chemical purchases, energy requirements, residuals disposal, and compliance monitoring. In some cases, the technology options may also result in costs that recur less frequently than annually (e.g., three-year recurring costs for equipment replacement) or one-time costs other than capital investment (e.g., one-time engineering costs).

For the analysis of these technology capital costs on an annualized basis, or when performing other cost and impact analyses that account for the service life of the installed equipment (e.g., electricity rate impact analysis), the number of years reflect the reasonably expected service life of the equipment. The EPA based its estimate of service life of equipment that may be installed for FGD wastewater or bottom ash transport water on a review of reported performance characteristics of compliance technology components. From this review, the EPA concluded that

the equipment could reasonably be expected to operate for 20 years or more, and thus further concluded that 20 years is an appropriate basis for cost and economic impact analyses that account for the estimated operating life of compliance technology. See the *Regulatory Impact Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more information on the EPA’s economic impact analyses (U.S. EPA, 2019).

## 5.2 FGD WASTEWATER

The EPA estimated costs for plants discharging FGD wastewater to install and operate the following technologies: chemical precipitation, CP+LRTR, CP+HRTR, membrane filtration, and thermal treatment.<sup>18</sup> The EPA also estimated the cost savings associated with plants ceasing operation of impoundments currently used to treat FGD wastewater.

For chemical precipitation (Section 5.2.2), the EPA included costs for the plants to install and operate the following:

- Treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- Chemical feed systems for lime, organosulfide, ferric chloride, and polymers.
- Solids-contact clarifier to remove suspended solids.
- Pollutant monitoring and analysis.
- Solids handling (sludge holding tank and filter press).
- Transportation and disposal of solids in a landfill.

For CP+LRTR (Section 5.2.3), the EPA included all the costs described above for the chemical precipitation system and included costs for the following:

- Treatment equipment (anoxic/anaerobic bioreactor, flow control, backwash supply, storage tanks).
- Chemical feed system for nutrients.
- Pretreatment system (for plants with nitrate/nitrite concentrations greater than 50 parts per million (ppm)).
- Heat exchanger.
- Ultrafilter.
- Pollutant monitoring and analysis.
- Transportation and disposal of solids in a landfill.

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<sup>18</sup> The EPA estimated compliance costs for thermal treatment; however, the EPA did not use that estimate as a basis for an FGD technology option for the proposed rule. See the “Thermal Evaporation Cost Methodology Memorandum” for more information (ERG, 2018).

For CP+HRTR (Section 5.2.4), the same technology basis as the 2015 rule BAT, the EPA included all the costs described above for the chemical precipitation system, and included costs for the following:

- Treatment equipment (anoxic/anaerobic biological treatment system, storage tanks, and backwash system).
- Chemical feed system for nutrients.
- Pretreatment system (for plants with nitrate/nitrite concentrations greater than 100 ppm).
- Heat exchanger (for plants in certain geographic locations).
- Pollutant monitoring and analysis.
- Transportation and disposal of solids in a landfill.

For membrane filtration (Section 5.2.5), the EPA included costs for the plants to install and operate the following:

- Treatment equipment (membrane filtration, reverse osmosis, and storage tanks).
- Pretreatment system (microfiltration skid).
- Concentrate management (brine mixing skid for solidification).
- Transportation and disposal of solids in a landfill.

Section 5.2.1 describes the cost inputs and the process for updating the FGD wastewater flow rates from the 2015 rule, Section 5.2.2 through Section 5.2.5 describe the cost methodologies for each of the technology options, and Section 5.2.6 describes the impoundment operation cost savings methodology.

### **5.2.1 FGD Cost Calculation Inputs**

To calculate plant-level engineering costs associated with implementing FGD wastewater treatment technologies, the EPA developed a cost calculation database containing a set of input values and a set of equations that define relationships between costs and FGD wastewater flow rates (ERG, 2019a). To establish the input values, the EPA compiled plant-specific details on FGD wastewater flow rates and discharge destinations, existing FGD wastewater treatment details, and use of on-site and off-site landfills by steam electric power plants operating wet FGD systems. As part of the 2015 rule, the EPA developed a similar set of input information from the Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data to calculate compliance costs. For this proposed rule, the EPA updated the input values using additional information gathered from industry and available from the Department of Energy (see Section 2). The EPA developed a list of generating units expected to incur FGD wastewater treatment compliance costs by identifying plants that operate wet FGD systems, taking into account changes made to their FGD treatment system, and generating units that, since the 2015 rule, have retired or converted to a fuel other than coal. The EPA also identified generating units that have announced plans to retire or convert their fuel source before December 31, 2028. This section describes the updates to cost inputs from the 2015 rule.

The EPA modified the overall cost methodology to account for two FGD wastewater flow rates for each plant discharging FGD wastewater: (1) the FGD purge flow rate and (2) the optimized FGD flow rate. The FGD purge flow rate is the typical amount of wastewater from the FGD scrubber that is sent to FGD wastewater treatment. The optimized FGD flow is a reduced FGD wastewater flow that takes into account a reduction in FGD wastewater purged from the system, where equipment metallurgy could accommodate increased chloride concentration in the FGD system. The EPA used the FGD purge flow rate (i.e., the pre-optimized flow rate) to calculate capital costs and the optimized FGD flow rate to estimate O&M costs, recognizing that well-operated plants would take steps to optimize the volume of water to be treated and normalize the flow where possible.

### *FGD Purge Flow Rate*

For plants where there were no retirements or fuel conversions of wet-scrubbed generating units, the EPA calculated the non-optimized FGD purge flow rates using the same methodology that was used for the 2015 rule (ERG, 2019b). For those plants where one or more wet-scrubbed generating units have been retired or converted to a non-coal fuel source (or have plans to do so by 2028), the EPA updated FGD purge flow rates, taking into account that FGD wastewater would no longer be produced by the retired/converted generating units.

The EPA used NPDES permit data to calculate FGD purge flow rates for new wet FGD systems that began operation since the 2015 rule. For plants whose permits were not available or did not specify a flow rate, the EPA estimated FGD purge flows using the amount of coal burned in a year and a factor for the median FGD flow rate per ton of coal burned per year. The EPA used data from Form EIA-923 to determine the type and amount of coal burned by each scrubbed unit and calculated the unit-level FGD purge flows using Equation 5-1.

$$\text{Unit-Level FGD Purge Flow (GPD)} = \text{Coal Burned} \times \text{Median Flow per Ton of Coal}$$

Equation 5-1

Where:

Coal Burned	= The reported coal burned by the steam electric generating units serviced by a wet FGD system (in tons per year). Data from 2016 Form EIA-923.
Median Flow per Ton of Coal	= The calculated median FGD wastewater flow rate per ton of coal burned, by the type of coal burned at the generating unit: 0.1454 for bituminous, 0.0392 for subbituminous, 0.2313 for lignite, and 0.1017 for any coal blend (in GPD/ton/year). Values were developed using data collected from the Steam Electric Survey (ERG, 2019b).

The EPA summed the unit-level FGD purge flow rates to estimate plant-level FGD purge flow rates for new steam electric power plants and new wet FGD systems.

The EPA used the FGD purge flow rates to calculate capital costs, which may overestimate the size and cost of the treatment system that plants would actually install; however, the EPA chose to use this flow rate for capital costs to ensure that installed treatment technologies would be able to accommodate the maximum possible FGD purge flow.

#### *Optimized FGD Flow Rate*

The EPA's cost analyses for the 2015 rule took into account that certain higher-flow plants would find it beneficial to take steps to optimize FGD purge flow as a way to reduce the size and associated cost of the FGD wastewater treatment system. During the 2015 rulemaking, the EPA recognized that flow optimization was a viable approach for plants of all sizes; however, at that time, the EPA accounted for such actions only for those plants with FGD purge flows greater than 1 million gallons per day (MGD) and where equipment metallurgy could accommodate the resulting increased chloride concentration in the FGD system. Since the 2015 rule, site visits, meetings with industry representatives, and other information EPA has confirmed that flow optimization is a realistic step that plants can take to reduce compliance costs. Many plants, including those with FGD purge flow rates well below 1 MGD, anticipate implementing flow optimization approaches as they upgrade their FGD wastewater treatment. Because of this, EPA's cost analyses for this proposed rule incorporate flow optimization for all wet-scrubbed plants where FGD system metallurgy can accommodate it.

In the cost analyses, the EPA adjusted the FGD purge flow described above by the flow optimization algorithm to determine the plant-level optimized FGD flow rate. For these optimized FGD flow rates, the EPA concluded that plants would optimize the FGD flow through the treatment system by either throttling down the purge flow or recycling a portion of the purge stream back to the FGD system. One effect of this reduced discharge flow is that chloride concentrations will increase somewhat (the mass of chlorides discharged would remain unchanged while the volume of water decreases; thus, the lower flow rate will contain a higher concentration of chlorides). The EPA used the Steam Electric Survey data to determine plant-specific FGD system constraints for maximum design chloride concentrations and operating chloride concentrations. Consistent with the flow minimization methodology used for the 2015 rule, the EPA identified individual plants as having the potential to optimize FGD purge flow if the operating chloride concentration is lower than 80 percent of the maximum design concentration. If the operating chloride concentration is not lower than 80 percent of the maximum design concentration, the EPA assumed that further flow optimization was not practical and the resulting optimized FGD flow rate is equal to the FGD purge flow. The EPA calculated the degree of flow optimization using Equation 5-2; this represents the percent by which the FGD purge can easily be reduced without threatening the metallurgical integrity of the FGD system.

$$\text{Plant-Specific Degree of Flow Optimization} = (\text{Design Max Cl Level} \times 0.8 - \text{Operating Cl Level}) / (0.8 \times \text{Design Cl Level})$$

Equation 5-2

Where:

Design Max Cl Level	=	Design maximum chlorides concentration as reported in Part B, Section 4 of the Steam Electric Survey (B4-3), or a design concentration specified in comments during the rulemaking for the 2015 rule (in ppm).
Operating Cl Level	=	Chlorides concentration in the FGD scrubber purge as reported in Part B, Section 5 of the Steam Electric Survey (B5-3) (in ppm). Where data were not available in Part B, Section 5, the maximum operating chloride concentration from Part B, Section 4 of the Steam Electric Survey (B4-2) was used.

The EPA limited the degree of flow optimization for each plant so that the resulting operating chloride level would not exceed 30,000 ppm or 80 percent of the plant-specific design maximum chloride level, whichever is lower.<sup>19</sup>

For any existing plant that did not have sufficient information in the Steam Electric Survey to calculate a plant-specific degree of flow optimization, or where data were available but considered confidential business information (CBI), the median plant-specific degree of flow optimization was used, 0.375.<sup>20</sup> The EPA calculated optimized FGD flows using the plant-specific degree of flow optimization in Equation 5-3.

$$\text{Optimized FGD Flow (GPD)} = \text{FGD Purge Flow} \times (1 - \text{Plant-Specific Degree of Flow Optimization})$$

Equation 5-3

Where:

FGD Purge Flow	=	For FGD systems included in 2015 rule population, plant-level FGD purge flow updated for retirements and refuels; for new FGD systems, plant-level FGD purge flow (sum of unit-level flows, calculated using Equation 5-1) in GPD.
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<sup>19</sup> Data in the record shows that biological treatment systems operate without impairment at chloride concentrations well above 30,000 ppm and TDS concentrations well over 100,000 ppm. Nevertheless, recognizing that power companies have expressed preference to operate such systems at moderate chloride levels, EPA's cost analyses are based on operating the FGD system so that chloride concentrations in the FGD purge do not routinely exceed 30,000 ppm.

<sup>20</sup> The EPA calculated the median plant-specific degree of flow optimization using the 2015 rule FGD population.

Plant-Specific Degree of Flow Optimization = The smallest system-level degree of flow optimization for each plant (calculated using Equation 5-2 or the median plant-specific degree of flow reduction, 0.375).

All new FGD systems identified since the 2015 rule were not adjusted to reflect any degree of flow optimization; instead, because they are expected to be operating as designed, the EPA set the optimized FGD flow equal to the FGD purge flow.

To estimate O&M costs, the EPA used optimized FGD flow rates, recognizing that well-operated plants would take steps to optimize the volume of water to be treated and normalize the flow where possible, which will allow for more realistic annual cost estimates. Implementing flow optimization is the more cost-effective approach for operating the treatment systems, and also has commensurate benefits such as enhanced worker safety since smaller volumes of treatment chemicals will require reduced handling by the operators.

#### *FGD Treatment-In-Place Data*

The EPA identified data on each plant's current level of treatment for its FGD wastewater (ERG, 2019c). For plants that are already treating the FGD wastewater using some form of chemical precipitation, biological treatment, or evaporation treatment, the EPA identified which specific treatment system components would still be needed to comply with the proposed rule and based estimates of the compliance costs on the specific equipment upgrades. The cost methodologies in Section 5.2.2 through Section 5.2.5 discuss treatment-in-place considerations for the different technology options evaluated for the proposed rule.

#### *Landfill Data*

Like the 2015 rule, the EPA used data from the Steam Electric Survey and other public sources to identify which plants operate on-site active/inactive landfills containing FGD solids. Plants without an on-site active/inactive landfill with combustion residuals were identified as off-site landfills. The EPA anticipates plants with on-site inactive landfills will resume disposal of FGD solids to the landfill if needed for implementation of an FGD technology option.

#### *Final CCR Decision Data*

As discussed in Section 3.3, the EPA applied the same methodology used in the 2015 rule to update the FGD population for changes in plant operations as a result of the CCR rule. The CCR rule sets requirements for managing impoundments and landfills containing CCRs. Based on the CCR requirements, the EPA expects that some plants will alter how they operate their current CCR impoundments, including by undertaking the following potential changes:

- Close the disposal surface impoundment<sup>21</sup> and open a new composite-lined disposal surface impoundment in its place.
- Convert the disposal surface impoundment to a new composite-lined storage impoundment.<sup>22</sup>
- Close the disposal surface impoundment and convert to dry handling operations.
- Make no changes to the operation of the disposal surface impoundment.

Consistent with the 2015 methodology, described in Section 9.4.1 of the 2015 TDD, the EPA developed a methodology to use the output analysis of the CCR rule to predict which of the four potential operational changes would likely occur at each coal-fired power plant that operates FGD disposal impoundments under the CCR rule, see Table 5-1.

**Table 5-1. ELG FGD Baseline Changes Accounting for CCR Rule**

CCR Rule Decision	Adjustment to ELG Baseline	Effect on ELG Costs <sup>a</sup>	Effect on ELG Loadings <sup>a</sup>
New disposal impoundment	No changes	No changes	No changes
New storage impoundment	No changes	No changes	No changes
Convert to dry handling	Plant has a BAT chemical precipitation system in place	Plant incurs the following costs: Mercury analyzer Compliance monitoring All biological treatment system costs (including transportation/disposal)	Baseline loadings are based on chemical precipitation treatment in place
No decision	No changes	No changes	No changes

a – Changes described are compared to the costs and loads that would have been calculated if the EPA was not accounting for the CCR rule.

### 5.2.2 Cost Methodology for Chemical Precipitation

The design basis used to estimate costs for chemical precipitation treatment systems is consistent with the 2015 rule and includes the following process steps:

- Flow equalization.
- Hydroxide precipitation, sulfide precipitation and iron coprecipitation using lime, organosulfide, and ferric chloride chemical addition in separate reaction tanks.

<sup>21</sup> For the CCR rule, a disposal surface impoundment is generally defined as an impoundment that is not dredged and all CCRs are left in place in perpetuity.

<sup>22</sup> For the CCR rule, a storage impoundment is generally defined as an impoundment that is periodically dredged and has its CCR disposed elsewhere such that it can continue operating indefinitely.



- Polymer addition and clarification to remove precipitants and other suspended solids.
- Acid addition for pH neutralization.
- Sand filtration for additional removal of suspended solids.

The EPA used data from the 2015 rule to develop cost curves representing the capital and O&M costs for the chemical precipitation treatment system. The cost curves presented below include the following components:

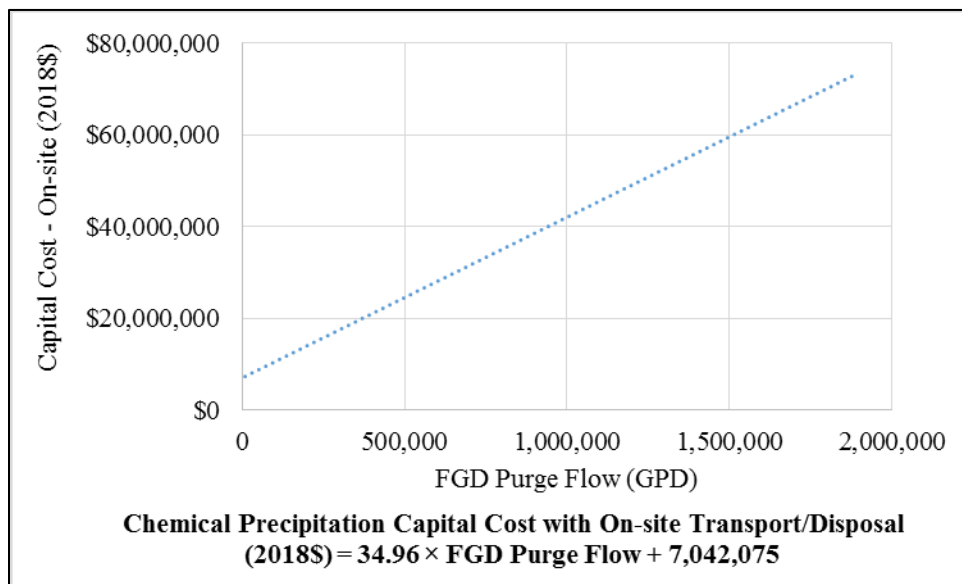
- Purchased Equipment Costs.
  - Pumps.
  - Tanks and mixers.
  - Reactors.
  - Chemical feed systems.
  - Clarifiers.
  - Filter presses.
  - Sand filters.
  - Pollutant monitoring and analysis (including a mercury analyzer).
- Direct Capital Costs.
  - Purchased equipment (including fabricated equipment and process machinery).
  - Freight.
  - Purchased equipment installation.
  - Instrumentation and controls (installed).
  - Piping (installed).
  - Electrical (installed).
  - Buildings (including services).
  - Site preparation.
- Indirect Capital Costs.
  - Engineering and supervision.
  - Construction expenses.
  - Contractor's fees.
  - Contingency.
- O&M Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Chemical purchase.
  - Energy.

- Sludge transportation and disposal.
- Compliance monitoring.

Section 9.6.1 of the 2015 TDD provides additional details on the design basis for chemical precipitation wastewater treatment systems. The EPA also calculated 6-year recurring costs to replace the mercury analyzer separately from the cost curves, as described below.

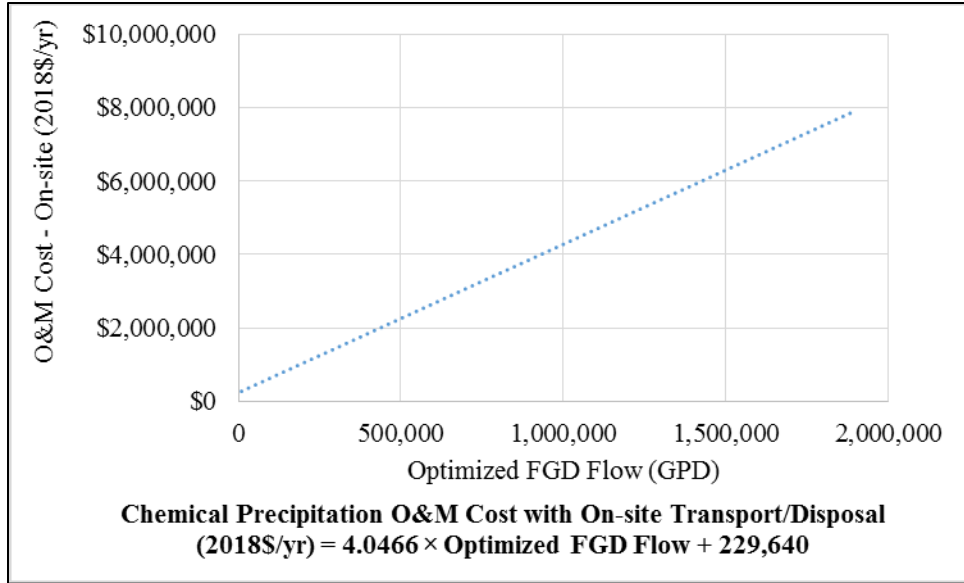
#### *Plant-Level Capital and O&M Cost*

The EPA used 2015 rule cost data and FGD purge flows to generate cost curves for estimating plant-level capital and O&M costs as a function of FGD purge flow rate and optimized FGD flow rate in GPD, respectively.<sup>23</sup> Because costs are affected by the solids disposal location (i.e., on-site landfill or off-site transportation and disposal), the EPA generated a set of cost curves for each transportation and disposal method (see Figure 5-1 and Figure 5-3 for capital costs and Figure 5-2 and Figure 5-4 for O&M costs). These cost curves reflect the costs to design, procure, install, and operate chemical precipitation treatment at plants where all components of the treatment system will need to be acquired, such as at plants operating surface impoundments to treat the FGD wastewater. To estimate plant-specific capital and O&M costs, the EPA used the appropriate curves based on whether or not the plant is identified as having an on-site or off-site landfill, as described in Section 5.2.1.

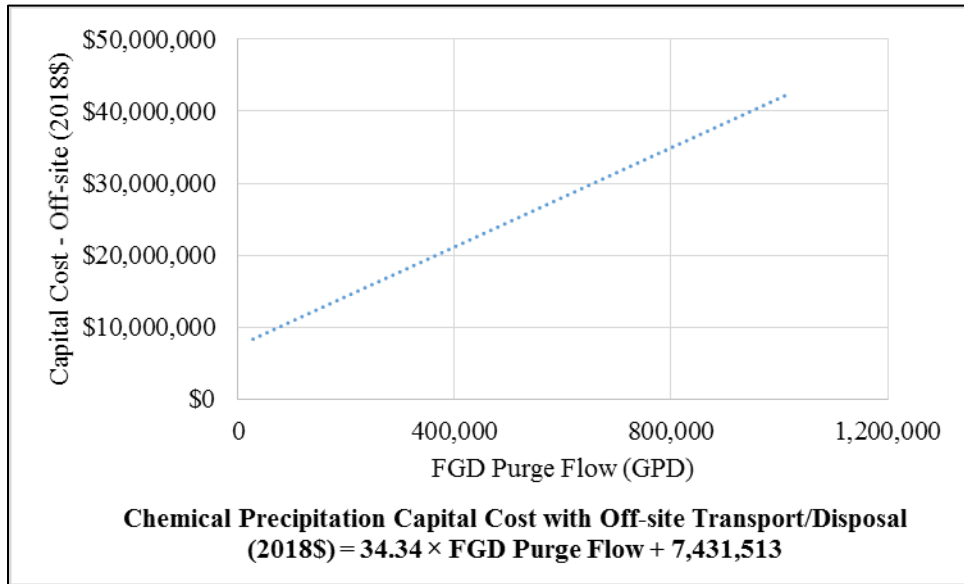


**Figure 5-1. Chemical Precipitation Capital Cost Curve – On-site Transport/Disposal**

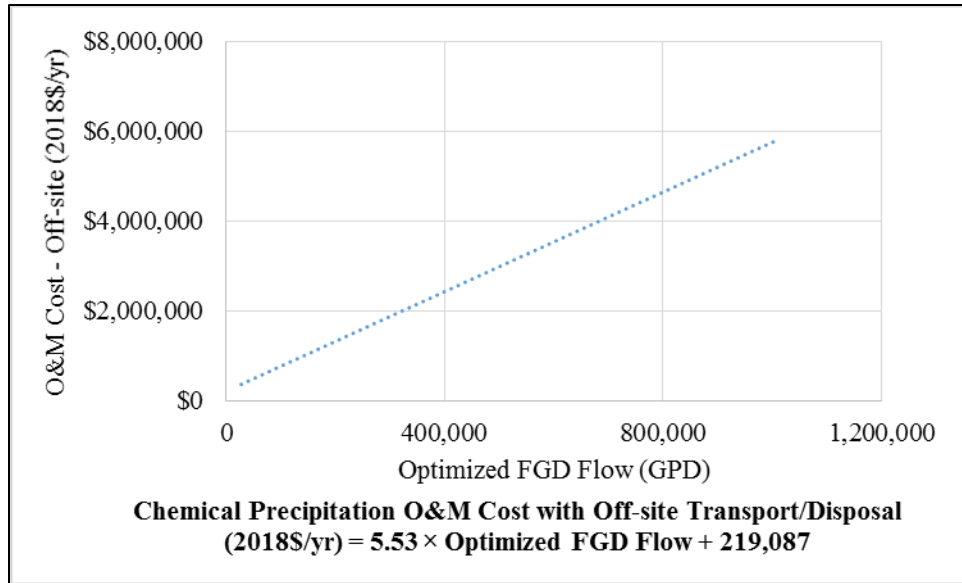
<sup>23</sup> The EPA adjusted the 2015 rule original cost data basis from 2010 to 2018 dollars using RS Means Historical Cost Indexes.



**Figure 5-2. Chemical Precipitation O&M Cost Curve – On-site Transport/Disposal**



**Figure 5-3. Chemical Precipitation Capital Cost Curve – Off-site Transport/Disposal**



**Figure 5-4. Chemical Precipitation O&M Cost Curve – Off-site Transport/Disposal**

#### *Recurring Costs*

The EPA’s cost analyses include additional costs for the chemical precipitation system that would be incurred periodically after installation but less frequently than annually. The EPA determined that a prudently designed treatment system would include a continuous water quality monitor for measuring mercury concentrations in the treatment system effluent. The mercury analyzer technology has been demonstrated as highly effective for FGD wastewater, and by providing near real-time results, it has enabled plant operators to proactively take steps to adjust the chemical precipitation process as needed to optimize pollutant removal. The EPA assumed that the expected life of a mercury analyzer is 6 years and that each plant will operate one analyzer for FGD wastewater. Plants with full or partial chemical precipitation costs incur a cost of \$100,000 (2018\$) to replace the mercury analyzer every 6 years.

#### *Treatment-In Place Adjustment for Capital and O&M Costs*

For each plant that already has components of chemical precipitation treatment in place as part of its treatment system, the EPA used Steam Electric Survey data to identify any upgrades needed to make the treatment system comport with the chemical precipitation design basis considered for this proposed rule. Depending on the capital upgrades needed or additional O&M costs that would be incurred, the EPA used guidelines presented in Table 5-2 to classify the plant as incurring high, medium, or low capital costs and high, medium, or low O&M costs. Then, for each classification, the EPA used cost data from the 2015 rule to calculate the median percentage of costs incurred by the plant compared to a full chemical precipitation treatment system (ERG, 2019d). The median percentages are presented in Table 5-2; these values were used to estimate the compliance costs that would be incurred by plants that already operate some components of the model chemical precipitation treatment system.

**Table 5-2. Percentage of Chemical Precipitation Costs Incurred by Plants with Treatment in Place**

Cost Category	Capital Costs		O&M Costs	
	Category Guidelines	Percent of Full Treatment System Cost Incurred	Category Guidelines	Percent of Full Treatment System Cost Incurred
High	Plants expected to incur costs for an equalization tank and other equipment such as a sand filter or chemical addition system.	27%	Plants expected to incur more than two chemical costs in addition to a mercury analyzer and monitoring (e.g., three chemical costs or two chemical costs and another O&M cost).	31%
Medium	Plants expected to incur costs for only an equalization tank (all or partial) or plants costed for a sand filter and chemical addition systems.	17%	Plants expected to incur costs for up to two chemicals, in addition to a mercury analyzer and monitoring.	13%
Low	Plants expected to incur costs for a mercury analyzer and for up to two chemical addition systems.	1%	Plants expected to incur costs for a mercury analyzer, monitoring, and minimal chemical costs.	6%

For plants with existing tank-based FGD wastewater treatment (i.e., not an impoundment system), the EPA calculated costs following the framework shown in Table 5-3. Partial capital and O&M costs were calculated using the appropriate percentage of full treatment system cost incurred from Table 5-2 for each plant. Compliance monitoring costs include sampling labor and materials as well as the costs associated with sample preservation, shipping, and analysis. The EPA estimated the annual cost for compliance monitoring to be \$73,600 (in 2018 dollars).

**Table 5-3. Costs Incurred for Chemical Precipitation for Plants with Treatment in Place**

Treatment in Place	Cost Incurred
Partial Chemical Precipitation	Partial capital and O&M costs (see Table 5-2)
Full Chemical Precipitation <sup>a</sup>	Compliance monitoring costs
Chemical Precipitation followed by LRTR, HRTR or other biological process (e.g., Suspended Growth Biological Treatment)	Compliance monitoring costs
Evaporation <sup>b</sup>	Zero costs

a – A full chemical precipitation treatment system includes ferric chloride, organosulfide, polymer, and acid addition, and/or meets the mercury and arsenic limitations established for chemical precipitation.

b – Reusing the treated effluent from evaporation treatment systems as scrubber makeup water or in other applications is more cost-effective than discharging this wastestream.

### 5.2.3 Cost Methodology for Chemical Precipitation followed by LRTR (CP+LRTR)

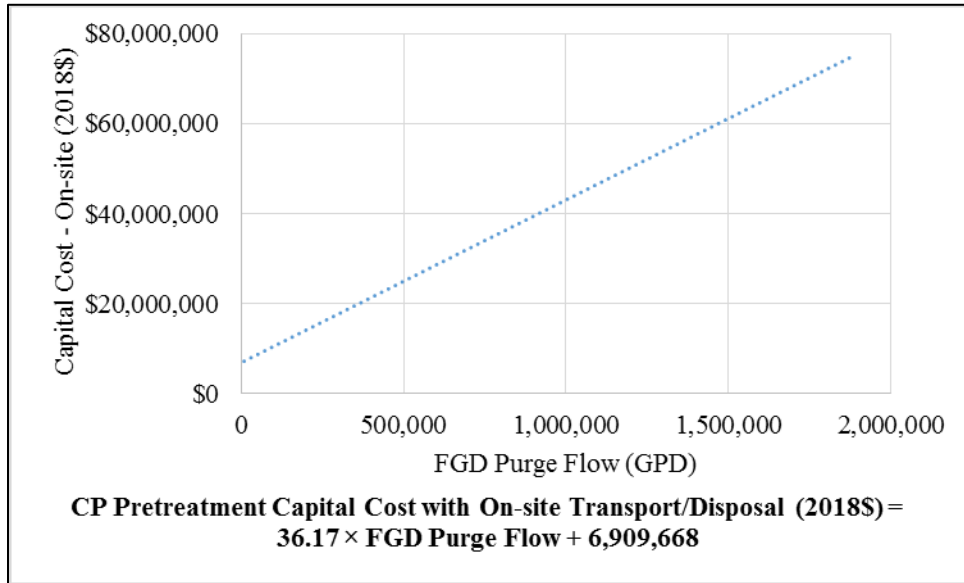
The design basis to estimate costs for CP+LRTR includes both chemical precipitation cost components (see Section 5.2.2) and LRTR cost components. The LRTR components of the model treatment technology include the following:

- Purchased Equipment Costs.
  - Anoxic/anaerobic bioreactors.
  - Control skids.
  - Backwash skids.
  - Tanks.
  - Pumps.
  - Heat exchanger.
  - Pretreatment system (for denitrification at applicable plants).
  - Ultrafilter.
  - Chemical feed skids.
  - Pollutant monitoring and analysis (including a mercury analyzer).
- Direct Costs.
  - Purchased equipment (including fabricated equipment and process machinery).
  - Freight.
  - Instrumentation and controls (installed).
  - Piping (installed).
  - Electrical (installed).
  - Buildings (including services).
  - Site preparation.
- Indirect Costs.
  - Engineering and supervision.
  - Contingency.
- O&M Costs.
  - Operating labor.
  - Maintenance labor.
  - Chemical purchase.
  - Energy.

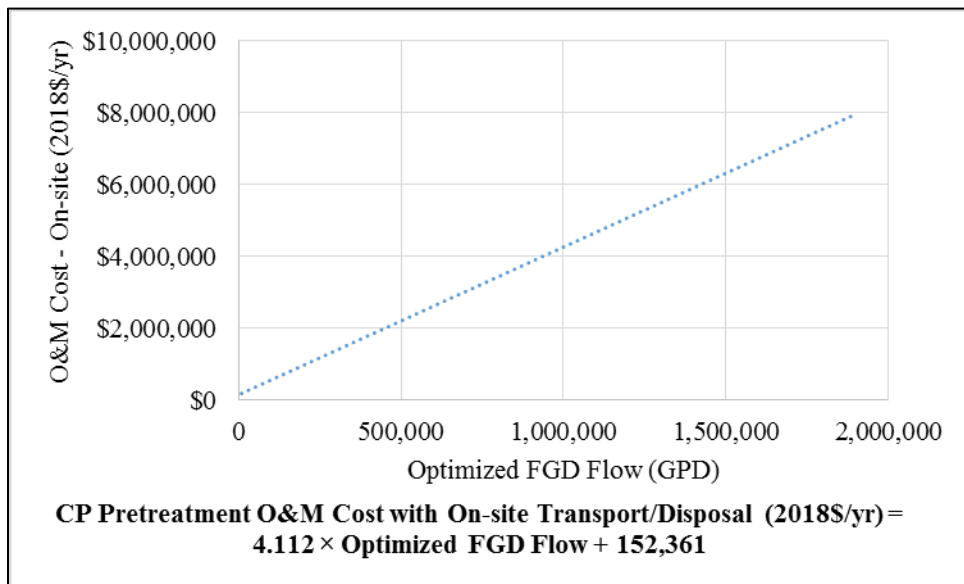
#### *Plant-Level Capital and O&M Cost*

The EPA's approach for estimating capital and O&M costs for the chemical precipitation pretreatment stage of the CP+LRTR model technology is similar to the methodology described

in Section 5.2.2.<sup>24</sup> Cost curves for the pretreatment stage with on-site disposal of treatment residuals are presented in Figure 5-5 and Figure 5-6; Figure 5-7 and Figure 5-8 present costs for pretreatment at plants that dispose of treatment residuals off site. To estimate plant-specific capital and O&M costs, the EPA used the appropriate curves based on whether the plant is identified as having an on-site or off-site landfill, as described in Section 5.2.1.

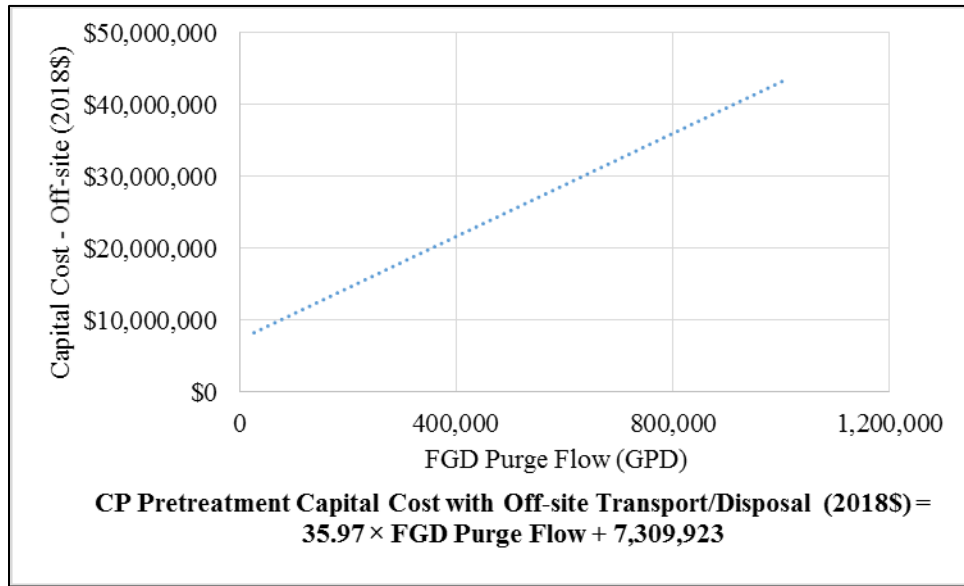


**Figure 5-5. CP Pretreatment Capital Cost Curve – On-site Transport/Disposal**

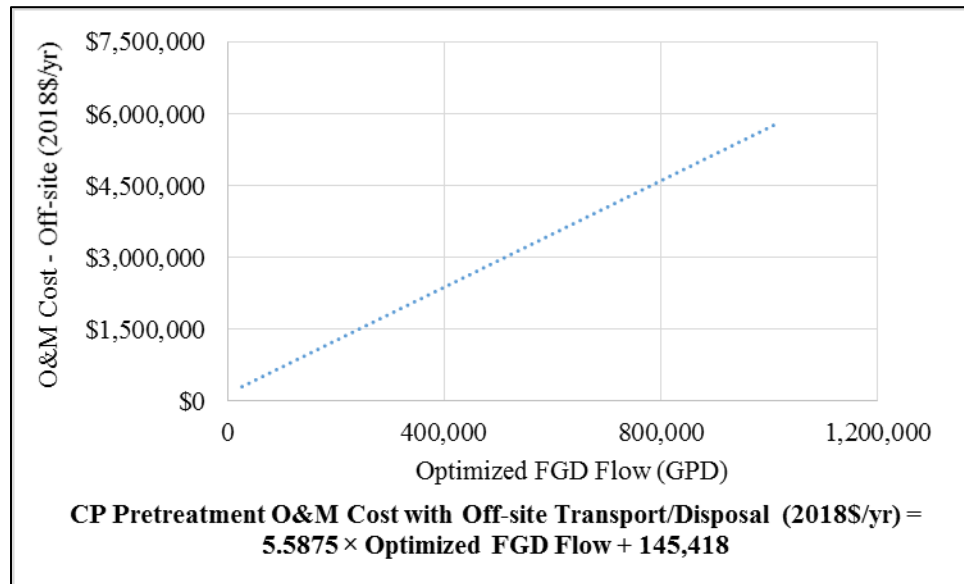


**Figure 5-6. CP Pretreatment O&M Cost Curve – On-site Transport/Disposal**

<sup>24</sup> These costs differ slightly from those presented in Section 8.2.2 due to additional components, including additional pumps, tanks, and piping, to account for holding and transporting partially treated water before further treatment in the LRTR system.



**Figure 5-7. CP Pretreatment Capital Cost Curve – Off-site Transport/Disposal**

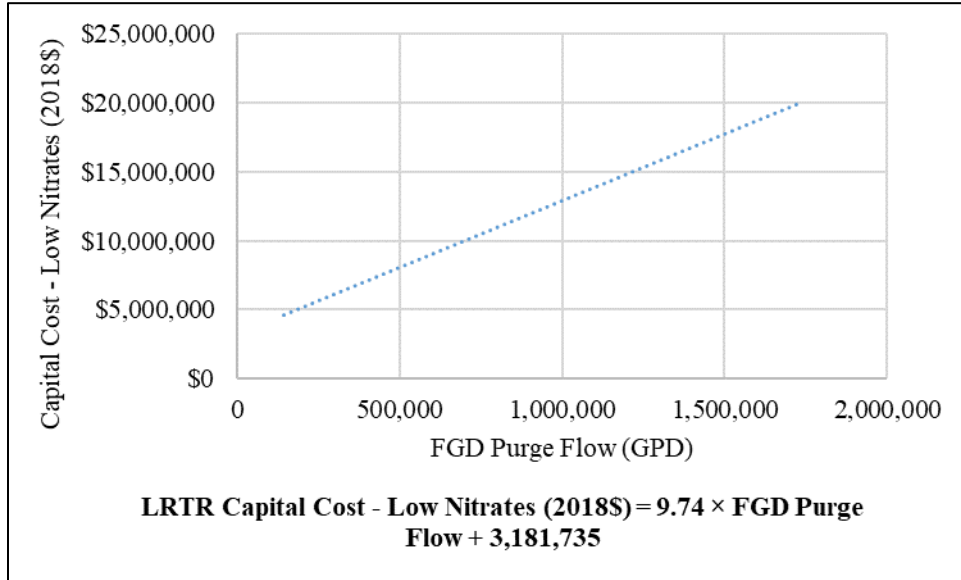


**Figure 5-8. CP Pretreatment O&M Cost Curve – Off-site Transport/Disposal**

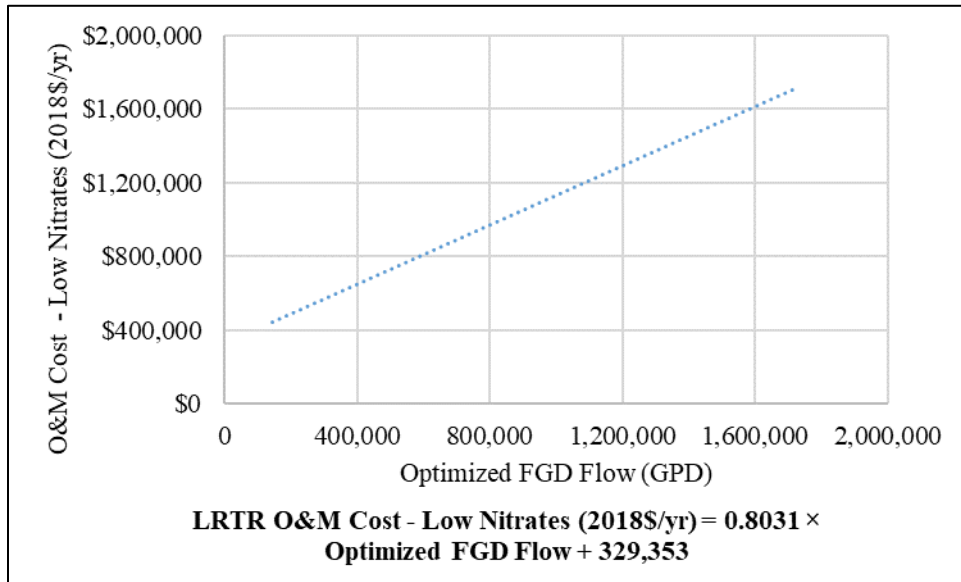
The EPA used cost information compiled for the 2015 rule, combined with additional data collected since then from power companies, treatment equipment vendors, engineering firms, and publicly available engineering cost references to develop capital and O&M cost curves for the LRTR stage of the CP+LRTR model technology (ERG, 2019e). The resulting cost curves differentiate between plants that may need to include an additional partial denitrification pretreatment step (for the model LRTR treatment technology, this was defined as plants with



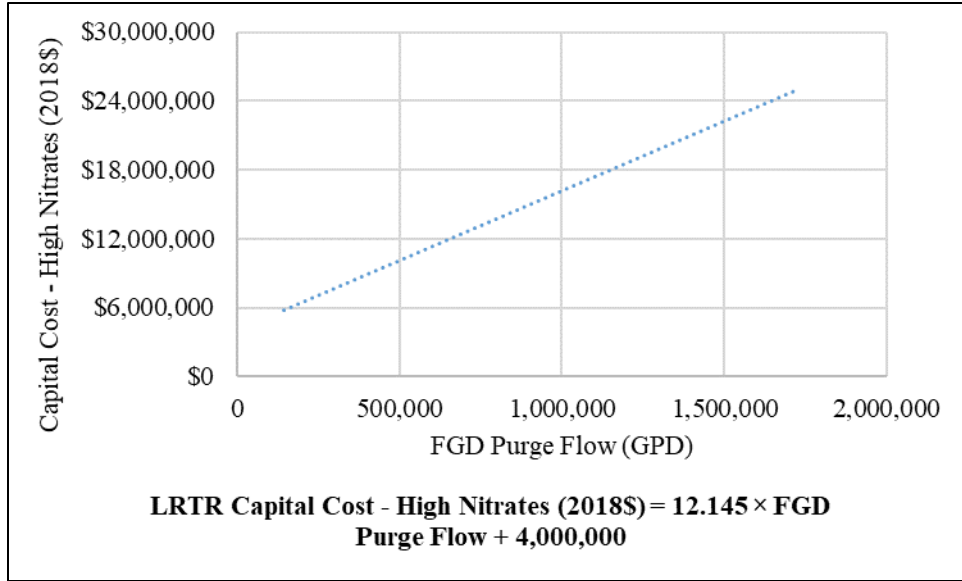
influent nitrate concentrations higher than 50 mg/L in untreated FGD purge). The EPA used low nitrates curves to estimate costs for all plants, except for the subset of plants where sampling data from the Analytical Database (ERG, 2015) and the Steam Electric Survey (ERG, 2019e) demonstrated nitrate/nitrite concentrations at or above 50 mg/L in FGD purge.



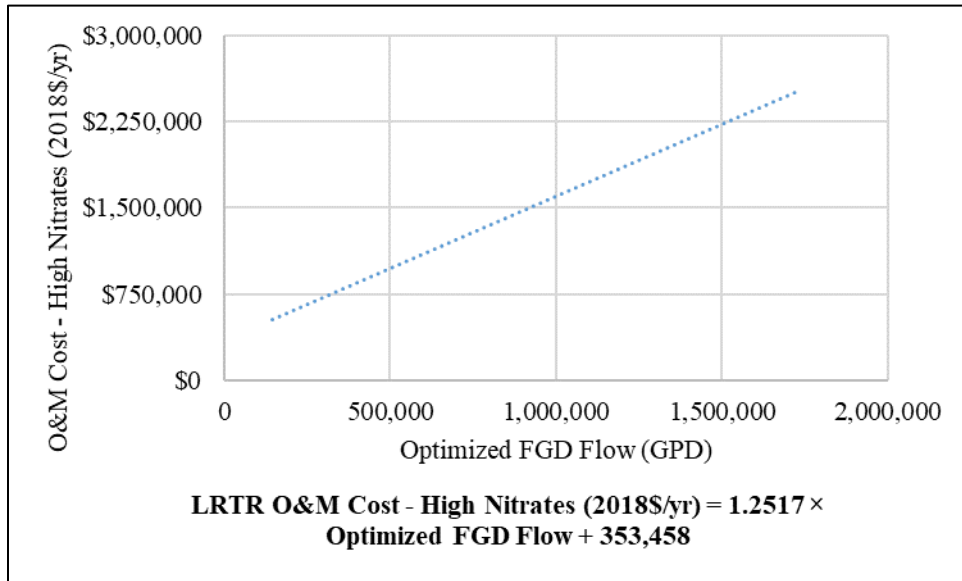
**Figure 5-9. LRTR Capital Cost Curve – Low Nitrates**



**Figure 5-10. LRTR O&M Cost Curve – Low Nitrates**



**Figure 5-11. LRTR Capital Cost Curve – High Nitrates**



**Figure 5-12. LRTR O&M Cost Curve – High Nitrates**

*Recurring Costs*

For all plants that are expected to incur costs beyond compliance monitoring, the EPA calculated the 6-year recurring cost for a mercury analyzer, as discussed in Section 5.2.2.

*Treatment-In-Place Adjustment for CP+LRTR Capital and O&M Costs*

For plants with FGD wastewater treatment in place (beyond an impoundment system), the EPA calculated the plant cost based on the costs listed in Table 5-4. Equalization tank capital costs are

equivalent to the median cost for a field erected equalization tank with a hydraulic residence time of 24 hours for flows between 70,000 GPD and 1,000,000 GPD for the 2015 rule costed population (\$823,000). Compliance monitoring O&M costs for the CP+LRTR technology option include costs to conduct annual compliance monitoring for arsenic, mercury, selenium, and nitrate/nitrite (\$75,600).

**Table 5-4. Costs Incurred for Chemical Precipitation plus LRTR for Plants with Existing Treatment in Place**

Treatment in Place	Cost Incurred
Partial Chemical Precipitation	Partial chemical precipitation as pretreatment capital and O&M costs (see Section 5.2.2 and Table 5-3), full LRTR capital and O&M costs based on plant-specific nitrate/nitrite concentrations.
Full Chemical Precipitation <sup>a</sup>	Full LRTR capital and O&M costs based on plant-specific nitrate/nitrite concentrations.
Chemical Precipitation followed by Suspended Growth Biological Treatment	Equalization tank capital cost and compliance monitoring costs.
Chemical Precipitation followed by LRTR or HRTR	Compliance monitoring costs.
Evaporation <sup>b</sup>	Zero costs

a – A full chemical precipitation treatment system includes ferric chloride, organosulfide, polymer, and acid addition, and/or meets the mercury and arsenic limitations established for chemical precipitation.

b – Reusing the treated effluent from evaporation treatment systems as scrubber makeup water or in other applications is more cost-effective than discharging this waste stream.

#### **5.2.4 Cost Methodology for Chemical Precipitation followed by HRTR (CP+HRTR)**

The CP+HRTR technology basis presented here is consistent with the BAT technology basis for the 2015 rule, chemical precipitation followed by anoxic/anaerobic biological treatment. The cost estimates for this technology option include the chemical precipitation cost components described in Section 5.2.2, as well as the following HRTR cost components:

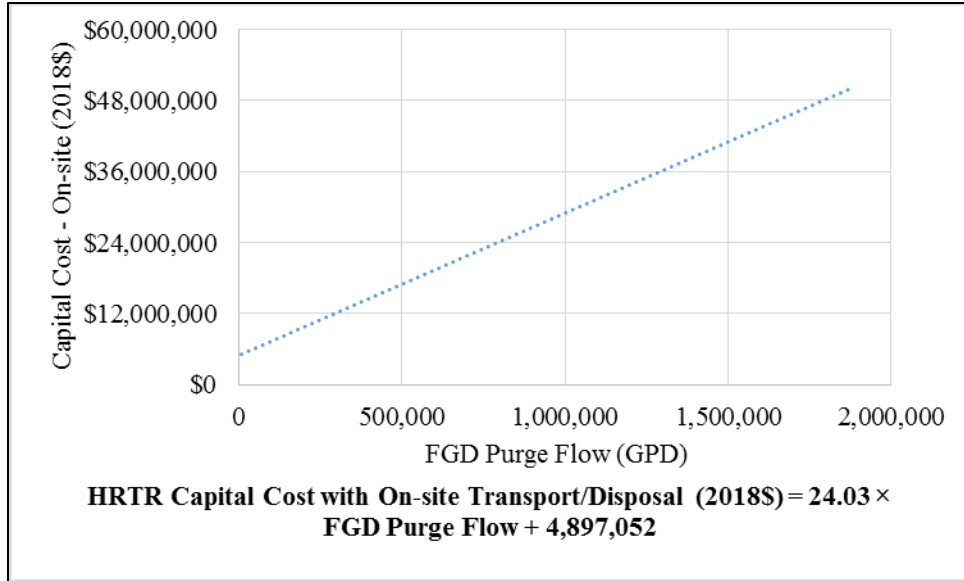
- Purchased Equipment Costs.
  - Anoxic/anaerobic biological system.
  - Tanks.
  - Pumps.
  - Heat exchanger (for applicable plants).
  - Backwash system.
  - Chemical feed systems.
  - Pretreatment system (for denitrification at applicable plants).
  - Pollutant monitoring and analysis (including a mercury analyzer ORP monitor).
- Direct Capital Costs.

- Purchased equipment (including fabricated equipment and process machinery).
- Freight.
- Purchased equipment installation.
- Instrumentation and controls (installed).
- Piping (installed).
- Electrical (installed).
- Buildings (including services).
- Site preparation.
- Indirect Capital Costs.
  - Engineering and supervision.
  - Construction expenses.
  - Contractor’s fees.
  - Contingency.
- O&M Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Chemical purchase.
  - Energy.
  - Sludge transportation and disposal.
  - Compliance monitoring.

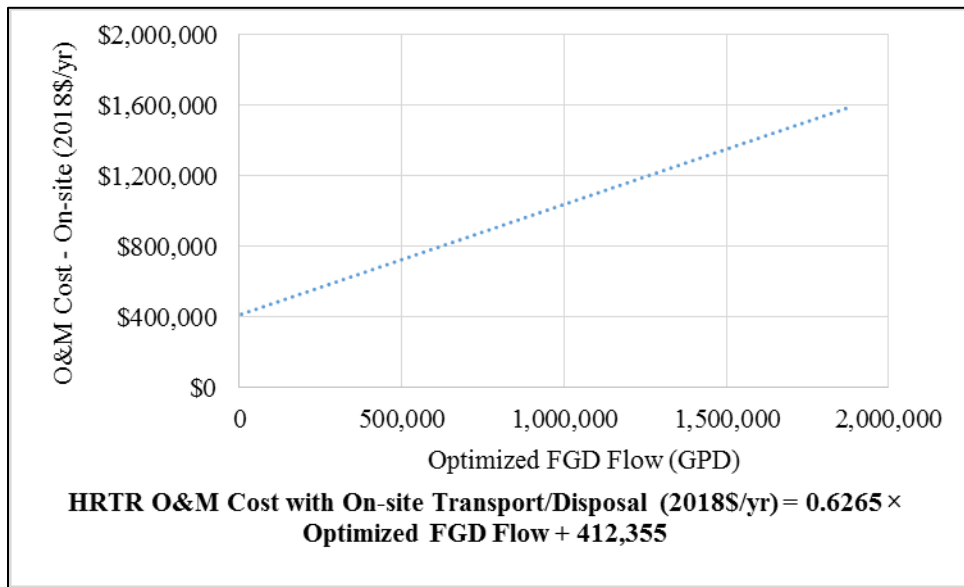
Section 9.6.2 of the 2015 TDD provides additional details on the design basis for HRTR.

#### *Plant-Level Capital and O&M Cost*

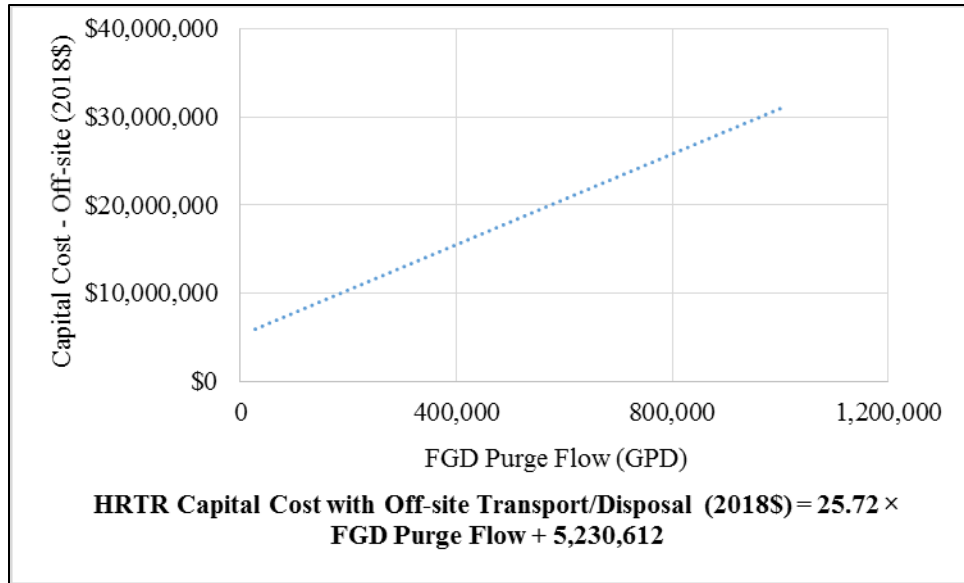
The EPA estimated pretreatment costs for a chemical precipitation system using the equations found in Section 5.2.3. Like the method described in Section 5.2.2 for chemical precipitation, the EPA used the 2015 rule data to establish cost curves for HRTR capital and O&M costs as a function of FGD purge flows and optimized FGD flows, respectively (ERG, 2019f). Based on data received following promulgation of the 2015 rule, the EPA adjusted HRTR costs to account for increased installation costs. The EPA also converted the 2015 rule costs from a cost basis of 2010 dollars to 2018 dollars. The EPA generated a set of cost curves for both on-site and off-site transportation and disposal (see Figure 5-13 and Figure 5-15 for capital costs and Figure 5-14 and Figure 5-16 for O&M costs). To estimate plant-specific capital and O&M costs, the EPA used the appropriate curves based on whether the plant is identified as having an on-site or off-site landfill, as described in Section 5.2.1.



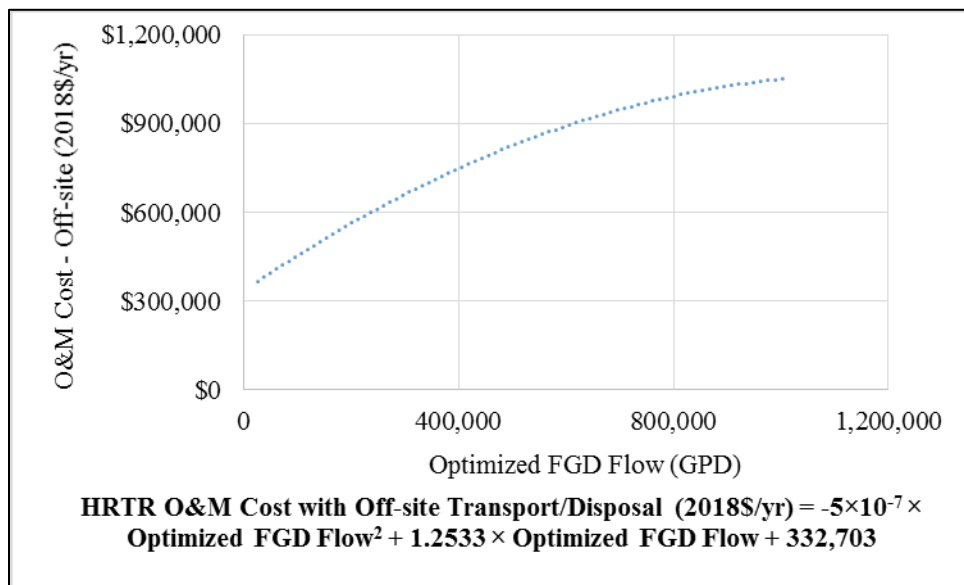
**Figure 5-13. HRTR Capital Cost Curve – On-site Transport/Disposal**



**Figure 5-14. HRTR O&M Cost Curve – On-site Transport/Disposal**



**Figure 5-15. HRTR Capital Cost Curve – Off-site Transport/Disposal**



**Figure 5-16. HRTR O&M Cost Curve – Off-site Transport/Disposal<sup>25</sup>**

For plants with a nitrate/nitrite concentration in the FGD purge at or above 100 mg/L, the EPA estimated additional capital and O&M costs for a denitrification treatment step using the 2015 rule methodology (Equation 5-4 and Equation 5-5). The EPA used low nitrates curves to estimate costs for all plants except for the subset of plants where sampling data from the

<sup>25</sup> The EPA anticipates updating this relationship between HRTR O&M costs with off-site transportation and disposal to a linear relationship for future cost analyses. Based on the current population, this would affect 12 plants that transport and dispose of solids in off-site landfills and result in an increase in O&M costs of approximately \$305,000 for the industry.

Analytical Database and the Steam Electric Survey demonstrated nitrate/nitrite concentrations at or above 50 mg/L in FGD purge (ERG, 2015).

$$\text{Denitrification Capital Costs (2018\$)} = -1.091 \times [(\text{FGD Purge Flow}) / (24 \text{ hr/day}) / (60 \text{ min/hr})]^2 + 3,601.1 \times [(\text{FGD Purge Flow}) / (24 \text{ hr/day}) / (60 \text{ min/hr})] + 501,971$$

Equation 5-4

$$\text{Denitrification O\&M Costs (2018\$)} = 2,699 \times [(\text{Optimized FGD Flow}) / (24 \text{ hr/day}) / (60 \text{ min/hr})] + 275,333$$

Equation 5-5

### Recurring Costs

For all plants that are expected to incur costs beyond monitoring, the EPA calculated the 6-year recurring cost for a mercury analyzer, as discussed in Section 5.2.2.

### Treatment in Place Adjustment for Plant-Level Capital and O&M Costs

For plants with existing FGD wastewater treatment more advanced than a surface impoundment, the EPA calculated the plant cost based on the costs listed in Table 5-5. Equalization tank capital costs are equivalent to the median cost for a field erected equalization tank with a hydraulic residence time of 24 hours for flows between 70,000 GPD and 1,000,000 GPD for the 2015 rule costed population (\$823,000). Compliance monitoring costs for the CP+HRTR technology option include costs to collect and analyze effluent samples for arsenic, mercury, selenium, and nitrate/nitrite, following the cost methodology used for the 2015 rule and converting to 2018 dollars (\$75,600).

**Table 5-5. Costs Incurred for Chemical Precipitation plus HRTR for Plants with Existing Treatment in Place**

Treatment in Place	Cost Incurred
Partial Chemical Precipitation	Partial chemical precipitation as pretreatment capital and O&M costs (see Section 5.2.2 and Table 5-2), full HRTR capital and O&M costs based on plant-specific nitrate/nitrite concentrations
Full Chemical Precipitation <sup>a</sup>	Full HRTR capital and O&M costs based on plant-specific nitrate/nitrite concentrations
Chemical Precipitation followed by LRTR or Suspended Growth Biological Treatment	Equalization tank capital cost and compliance monitoring costs
Chemical Precipitation followed by HRTR	Compliance monitoring costs
Evaporation <sup>b</sup>	Zero costs

a – A full chemical precipitation treatment system includes ferric chloride, organosulfide, polymer, and acid addition, and/or meets the mercury and arsenic limitations established for chemical precipitation.

b – Reusing the treated effluent from evaporation treatment systems as scrubber makeup water or in other applications is more cost-effective than discharging this wastestream.

### 5.2.5 Cost Methodology for Membrane Filtration

The design basis for the membrane technology option includes pretreatment for removing suspended solids, membrane filtration, and encapsulation of the membrane reject stream (i.e., brine) using a solidification process. The membrane filtration process produces a permeate stream that is higher quality than the water used in the FGD system for limestone slurry makeup, mist eliminator wash, and other processes. Because the FGD system is a net water consumer, plants using this treatment technology would most likely recycle the permeate within the FGD process operations; therefore, no compliance monitoring costs would be incurred.

The EPA used capital and O&M cost data collected from industry sources and technology vendors to develop cost methodologies that estimate plant-specific costs for pretreatment, membrane filtration, brine management, and disposal of solidification solids. The membrane treatment technology basis includes the following cost components:

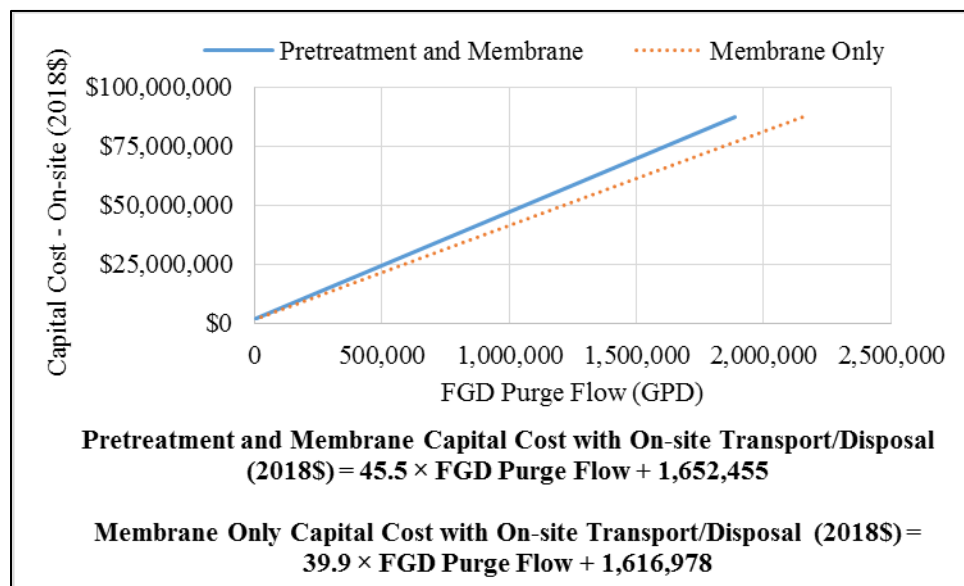
- Purchased Equipment Costs.
  - Membrane filtration skids.
  - Tanks.
  - Pumps.
  - Pretreatment system (for reverse osmosis at applicable plants).
  - Brine mixing skid for concentrate management.
- Direct Capital Costs.
  - Purchased equipment (including fabricated equipment and process machinery).
  - Freight.
  - Purchased equipment installation.
  - Instrumentation and controls (installed).
  - Piping (installed).
  - Electrical (installed).
  - Buildings (including services).
  - Site preparation.
- Indirect Capital Costs.
  - Engineering and supervision.
  - Construction expenses.
  - Contractor's fees.
  - Contingency.
- O&M Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Chemical purchase.



- Energy.
- Sludge transportation and disposal.

### *Plant-Level Capital and O&M Cost*

The cost data were used to establish relationships between capital costs and FGD purge flow rates, and between O&M costs and optimized FGD flow rates, respectively (ERG, 2019g). Similar to methodologies for other treatment technologies, the EPA constructed curves to differentiate between on-site and off-site transportation and disposal. For each set of curves, the EPA also differentiated between costs for systems that require pretreatment for solids (identified as “Pretreatment and Membrane” in the figures below) and systems that do not require pretreatment for solids (identified as “Membrane Only” in the figures below). Plants with existing treatment more advanced than surface impoundments were considered to have sufficient pretreatment for the membrane and costs were estimated using the Membrane Only cost curves. Costs for all other plants were estimated using the Pretreatment and Membrane curves to account for solids pretreatment costs (see Figure 5-17 and Figure 5-19 for capital cost curves and Figure 5-18 and Figure 5-20 for O&M cost curves). To estimate plant-specific capital and O&M costs, the EPA used the appropriate curves based on whether the plant is identified as having an on-site or off-site landfill, as described in Section 5.2.1.



**Figure 5-17. Membrane Capital Cost Curves – On-site Transport/Disposal**

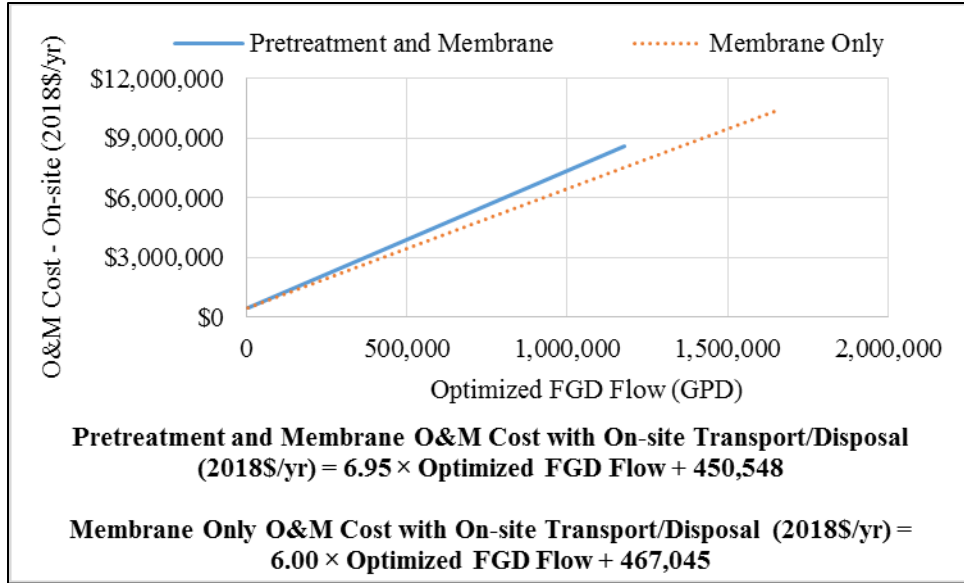


Figure 5-18. Membrane O&M Cost Curves – On-site Transport/Disposal

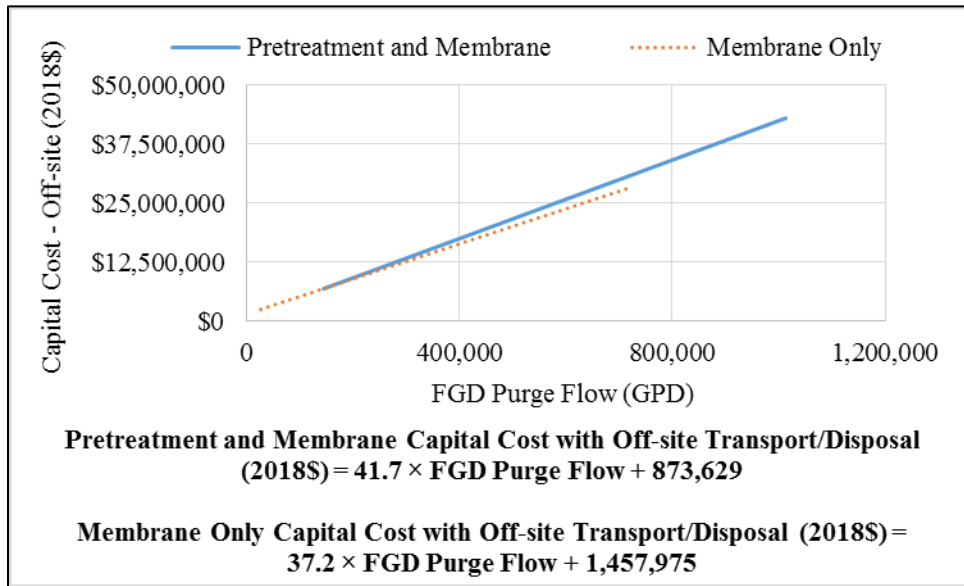
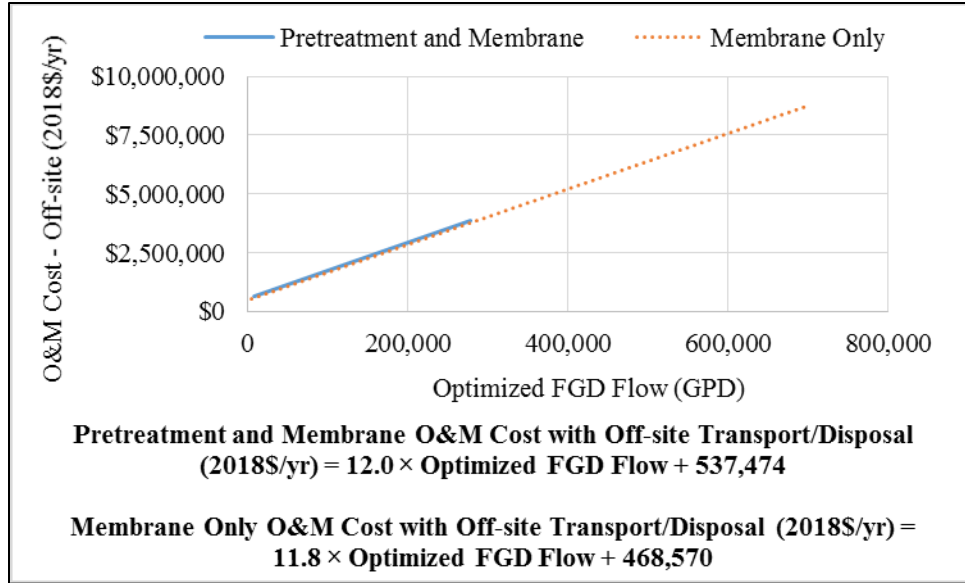


Figure 5-19. Membrane Capital Cost Curves – Off-site Transport/Disposal



**Figure 5-20. Membrane O&M Cost Curves – Off-site Transport/Disposal**

*Treatment in Place Adjustment for Plant-Level Capital and O&M Costs*

For plants with existing FGD wastewater treatment in place more advanced than a surface impoundment, the EPA calculated the plant cost based on the costs listed in Table 5-6.

**Table 5-6. Membrane TIP Summary of Costs**

Treatment in Place	Cost Incurred
Partial or Full Chemical Precipitation, LRTR, HRTR, or Suspended Growth Treatment.	Membrane only capital and O&M costs.
Evaporation <sup>a</sup>	Zero costs.
Other Treatment in Place.	Full capital and O&M costs.

a – Reusing the treated effluent from evaporation treatment systems as scrubber makeup water or in other applications is more cost-effective than discharging this wastestream.

In addition, plants that currently discharge FGD wastewater to a publicly owned treatment works (POTW) receive a cost savings for treating their wastewater on site and ceasing discharges to the POTW, unique to the membrane technology option. The EPA identified two plants from the Steam Electric Survey data that discharge FGD wastewater to a POTW. Using the POTW-specific rate structures, the EPA estimated the annual costs incurred by these plants for discharging to a POTW and deducted these annual costs (ERG, 2019g).

**5.2.6 Methodology for Estimating Cost Savings from Ceasing Use of FGD Surface Impoundments**

When plants install more advanced FGD wastewater treatment, they will experience some cost savings associated with ceasing operations of the FGD wastewater surface impoundment(s). This decrease in impoundment operations costs will offset the cost to operate the new treatment system, to some degree. The EPA estimated the annual O&M and recurring costs associated with

on-site impoundments and subtracted these costs from the estimated compliance costs for the technologies described above in this section, consistent with the 2015 methodology. The FGD impoundment operating cost savings quantified by the EPA include costs associated with the following:

- Wastewater transport system (i.e., pipelines, vacuum source) used to pump wastewater from the FGD scrubber to the impoundment.
- Impoundment site (i.e., general operation of the impoundment and inspections).
- Wastewater treatment processes (e.g., pH control).
- Water recycle system at the impoundment (if applicable).
- FGD earthmoving costs (e.g., front-end loader, removing/stacking combustion residuals at the impoundment site).

The EPA used Steam Electric Survey data to identify plants that have at least one impoundment containing FGD wastewater and at least one generating unit not designated as retired or planned. For those plants that have upgraded the FGD wastewater treatment system since the 2015 rule, the EPA assumed that their impoundments would cease operation.<sup>26</sup> The EPA estimated plant-level costs for operating impoundments based on the total amount of FGD solids currently handled wet at the plant. The EPA estimated the total FGD impoundment O&M cost savings using Equation 5-6.

$$\text{Total FGD Impoundment O\&M Cost Savings (2018\$/yr)} = (\text{FGD Impoundment Operating Cost Savings} + \text{FGD Earthmoving Cost Savings}) \times (\text{2018 Cost Index} / \text{2010 Cost Index})$$

Equation 5-6

Where:

FGD Impoundment Operating Cost Savings	= Impoundment operating cost savings (in 2010\$) (see Equation 5-9).
FGD Earthmoving Cost Savings	= O&M cost associated with the earthmoving equipment required (in 2010\$) (see Equation 5-11).
2010 Cost Index	= 183.5, the RSMeans Historical Cost Index for 2010.
2018 Cost Index	= 215.8, the RSMeans Historical Cost Index for 2018.

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<sup>26</sup> Once the FGD wastewater treatment system is upgraded to a more advanced technology (e.g., CP+LRTR), the impoundment provides little value with respect to pollutant removal and remains a substantial liability (for example, due to structural integrity failure).

*FGD Impoundment Operating Annual Cost Savings*

The EPA estimated the FGD impoundment operating cost savings by first calculating the plant MW factor and the plant-specific unitized cost using Equation 5-7 and Equation 5-8.

$$\text{Plant MW Factor (MW)} = 7.569 \times (\text{Plant Size})^{-0.32}$$

Equation 5-7

Where:

Plant Size = Plant size (in MW). The plant nameplate capacity for only those generating units serviced by a wet FGD system from responses to Question A1-13 in the Steam Electric Survey.

$$\text{Plant-Specific Unitized Cost (2010\$/ton)} = (\text{Impoundment Operating Unitized Cost}) \times (\text{Plant MW Factor})$$

Equation 5-8

Where:

Impoundment Operating Unitized Cost = The unitized annual cost to operate a combustion residual impoundment. The EPA used the unitized cost value of \$7.35 (in 2010\$/ton).

Plant MW Factor = Factor to adjust combustion residual handling costs based on plant capacity (in MW) (see Equation 5-7).

Next, the EPA estimated the total amount of FGD solids handled wet using the optimized FGD flow rate in GPD described in Section 5.2.1 and the average total suspended solids (TSS) concentration from EPA's Field Sampling Program, which was conducted in support of the 2015 rule. The EPA calculated the FGD impoundment operating cost savings by multiplying the plant-specific unitized cost (see Equation 5-8) by the amount of wet FGD solids using Equation 5-9.

$$\text{FGD Impoundment Operating Cost Savings (2010\$/year)} = (\text{Plant-Specific Unitized Cost}) \times [(\text{Optimized FGD Flow}) \times (\text{Average TSS Concentration}) \times (3.785 \text{ L/gal}) \times (0.001 \text{ g/mg}) \times (1.102 \times 10^{-6} \text{ tons/g}) \times (365 \text{ days/year})]$$

Equation 5-9

Where:

Optimized FGD Flow = Optimized FGD flow rate (in GPD) (see Equation 5-3).

Average TSS Concentration = The average influent TSS concentration for FGD wastewater treatment influent sampled as part of the 2015 rule (16,513 mg/L) (ERG, 2015).

### *FGD Earthmoving Annual Cost Savings*

To calculate FGD earthmoving cost savings, the EPA first calculated the plant-specific front-end loader unitized cost by multiplying the plant MW factor and the front-end loader unitized cost using Equation 5-10.

$$\text{Plant-Specific Front-End Loader Unitized Cost (2010\$)} = (\text{Front-End Loader 2010 Unitized O\&M Cost}) \times (\text{Plant MW Factor})$$

Equation 5-10

Where:

Front-End Loader Unitized O&M Cost = The unitized cost value that represents the operation and maintenance of the front-end loader used to redistribute FGD solids at an impoundment. This value was calculated to be \$2.49 (in 2010\$/ton).

Plant MW Factor = Factor to adjust combustion residual handling costs based on plant capacity (in MW) (see Equation 5-7).

Next, the EPA estimated the amount of combustion residuals (in tons) using the plant's optimized FGD flow, in gallons per day, and the average TSS concentration from EPA's Field Sampling Program. The EPA calculated the FGD earthmoving cost savings using Equation 5-11.

$$\text{FGD Earthmoving Cost Savings (2010\$/yr)} = (\text{Plant-Specific Front-End Loader Unitized Cost}) \times [(\text{Optimized FGD Flow}) \times (\text{Average TSS Concentration}) \times (3.785 \text{ L/gal}) \times (0.001 \text{ g/mg}) \times (1.102 \times 10^{-6} \text{ tons/g}) \times (365 \text{ days/year})]$$

Equation 5-11

Where:

Optimized FGD Flow = Optimized FGD flow rate (in GPD) (see Equation 5-3 in Section 5.2.1).

Average TSS Concentration = The average influent TSS concentration for FGD wastewater treatment influent sampled as part of the EPA Steam Electric Rulemaking effort (16,513 mg/L) (ERG, 2015).

### FGD Earthmoving Recurring Costs

The EPA calculated 10-year recurring cost savings associated with operating the earthmoving equipment (i.e., front-end loader) by determining the cost and average expected life of a front-end loader. The EPA determined the 2018 cost of the earthmoving equipment to be \$474,000 and assumed that the expected life of a front-end loader is 10 years. The EPA anticipated that each plant will operate one front-end loader if the plant is identified for impoundment savings.

### 5.3 BOTTOM ASH TRANSPORT WATER

The EPA estimated costs associated with zero discharge and high recycle rate technology options for this proposed rule. As described in the preamble, one proposed subcategorization option includes a generating unit utilization threshold (MWh). For the generating units falling below this threshold, and identified as low utilization, the EPA estimated costs associated with a best management practices (BMP) plan instead of the high recycle rate technology option. For each technology option considered, the EPA estimated the costs associated with installing additional handling or treatment technologies that eliminate or reduce the discharge of bottom ash transport water. The EPA then compared these costs to the cost to comply with the 2015 rule requirements, equivalent to the zero discharge technology options, to estimate incremental costs and savings to the steam electric power generating industry. Table 5-7 lists the technologies the EPA used as the basis for the three bottom ash technology options considered. The EPA also estimated the cost savings associated with plants ceasing operation of impoundments currently used for the treatment of bottom ash transport water (see Section 5.3.7).

**Table 5-7. Technology Options for Bottom Ash Transport Water**

Technologies	Technology Options		
	Zero Discharge	High Recycle Rate	High Recycle Rate/BMP Plan
Mechanical Drag System (MDS) (Section 5.3.2)	✓	✓	✓
Remote MDS (rMDS) with Reverse Osmosis (RO) treatment of a slipstream (Section 5.3.3)	✓		
rMDS with a purge (Section 5.3.4)		✓	✓
Bottom ash improved management (Section 5.3.5)	✓	✓	✓
Bottom ash BMP plan <sup>a</sup> (Section 5.3.6)			✓

a – Applied only to plants with generating units with a 2016 EIA net generation less than or equal to 876,000 MWh, excluding those with a generation capacity less than or equal to 50 MW.

The EPA used MDS and rMDS as the two main bases for estimating compliance costs for the technology options evaluated. For all generating units discharging bottom ash transport water from impoundment-based wet sluicing systems, the EPA first estimated costs to convert to an MDS and to an rMDS. The EPA evaluated both technologies because the MDS is the most commonly used dry handling/closed-loop system operating in the industry, but some plants have opted for the rMDS either because of economies of scale when used for multiple units, less

disruption of plant operations while converting the ash handling system, or constraints imposed by boiler house configuration.<sup>27</sup> The EPA then selected the technology with the lowest annualized costs for each plant to determine the technology likely to be installed, and considered any additional costs and cost savings associated with each technology option.<sup>28</sup>

For the MDS, the EPA included costs to replace the existing boiler hopper and associated equipment, and to install and operate a semi-dry silo for temporary storage of the bottom ash.

For the rMDS, the EPA included the costs to install and operate the following:

- rMDS (away from the boiler).
- Sump.
- Recycle pumps.
- Chemical feed system.<sup>29</sup>
- Semi-dry silo.

For the zero discharge option only, the EPA included additional costs for the treatment of a slipstream from the rMDS using a reverse osmosis membrane in order to operate the system to achieve zero discharge. The EPA applied these costs to plants currently operating an rMDS as well as any other plants estimated to install the technology.

The EPA estimated a cost to prepare and implement a BMP plan for generating units with low utilization.<sup>30</sup> These costs include the initial development and annual review of a BMP plan to recycle as much bottom ash transport water determined practicable, and capital and operation and maintenance (O&M) costs for pumps and piping associated with the recycle system.

The EPA identified several plants that operate bottom ash wet handling systems as closed-loop systems. These plants did not report any discharge of bottom ash transport water in the Steam Electric Survey. However, based on other information in the survey responses, the EPA determined that these plants have retained the capability to discharge bottom ash transport water from emergency outfalls. The cost methodology approach used for these plants is described in Section 5.3.5.

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<sup>27</sup> There are alternative ash handling technologies to the MDS and rMDS that can alleviate these issues (e.g., pneumatic bottom ash handling) and these alternatives have been used at plants in the U.S. and internationally; however, EPA's cost analyses are based on MDS and rMDS. Estimates based on MDS and rMDS are sufficiently comparable to alternative bottom ash handling approaches to use for evaluating costs and economic achievability.

<sup>28</sup> Consistent with the approach used for the 2015 rule, for plants where the EPA is aware that physical constraints preclude installation of the MDS technology, the EPA based costs on rMDS.

<sup>29</sup> The EPA included costs for a chemical feed system to control pH, should that become necessary to prevent scaling within the system. Information in the record indicates that few, if any, plants are likely to need to use such systems. However, because the EPA could not conclusively determine that none of the plants would need the chemical feed system to control pH of the recirculating system, nor which of the plants would be more likely to need the system; costs were included for all plants. This likely overestimates the compliance costs for most plants; however, the cost for chemical addition is relatively small in relation to other costs for the rMDS.

<sup>30</sup> Applied only to plants with generating units with a 2016 EIA net generation less than or equal to 876,000 MWh, excluding those with a generation capacity less than or equal to 50 MW.



The EPA also included the capital and O&M costs of transporting and disposing of all bottom ash to a landfill for the technology options considered.

### **5.3.1 Bottom Ash Cost Calculation Inputs**

To calculate plant-level engineering costs associated with implementing bottom ash transport water technologies, the EPA developed a cost calculation database containing a set of input values as well as a set of equations that define relationships between costs and generating unit capacity or bottom ash generation (ERG, 2019h). To establish the set of inputs, the EPA compiled generating-unit-specific details on bottom ash production, current bottom ash handling system details, and information on the use of on-site and off-site landfills by steam electric power plants discharging bottom ash transport water.

As part of the 2015 rule, the EPA developed a similar set of input information from the Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data to calculate compliance costs. For this proposed rule, the EPA updated the input values using additional information gathered from industry and available from the Department of Energy and NPDES permits (see Section 2). The EPA developed a list of generating units expected to incur bottom ash compliance costs by identifying plants that discharge bottom ash transport water, taking into account changes made to handling systems, as well as retirements and conversions (to a fuel other than coal) of generating units since the 2015 rule. The EPA also identified generating units that have announced plans to retire or convert their fuel source before December 31, 2028. This section describes the updates to cost inputs from the 2015 rule.

#### *Bottom Ash Production Data*

For each applicable generating unit, the EPA estimated the amount of wet bottom ash produced in tons per year (TPY), generating capacity in MW, and net generation in MWh. The EPA used bottom ash production and capacity values reported in the Steam Electric Survey as input values for estimating implementation costs for the proposed rule. The EPA used generating unit-level net generation values reported in the 2016 EIA data to identify low utilization generating units.

#### *Bottom Ash Cost Type Flags*

The EPA used data from the Steam Electric Survey, site visits, and other industry-provided data, discussed in Section 2, to identify the type of bottom ash handling systems currently operating at each plant. The EPA used this information to determine what equipment or services the plants would have to acquire to apply each technology option. The EPA flagged plants for one or more of the following:

- Steam electric generating units equipped with only wet bottom ash handling systems that discharge bottom ash transport water.
- Steam electric generating units equipped with only wet bottom ash handling systems that discharge bottom ash transport water and have space constraints preventing the installation of an MDS.
- Steam electric generating units already operating an rMDS system.

- Steam electric generating units equipped with only wet bottom ash handling systems that recycle all of their bottom ash sludge, but have the ability to discharge bottom ash transport water from emergency outfalls.
- Steam electric generating units operating a dry bottom ash handling system.

### Landfill Data

Like the 2015 rule, the EPA used data from the Steam Electric Survey and other public sources to identify which plants operate on-site active/inactive landfills containing bottom ash. Plants without an on-site active/inactive landfill with combustion residuals were identified as off-site landfills. The EPA anticipates plants with inactive on-site landfills will resume disposal of bottom ash to the landfill if necessitated by implementation of a bottom ash transport water technology option.

### Final CCR Decision Input Data

As discussed in Section 3.3, the EPA applied the same methodology used in the 2015 rule to update the bottom ash population for changes in plant operations as a result of the CCR rule. The CCR rule sets requirements for managing impoundments and landfills containing CCRs. Based on the CCR requirements, the EPA expects that some plants will potentially undertake the following changes in how they operate their current CCR impoundments:

- Close the disposal surface impoundment<sup>31</sup> and open a new composite-lined disposal surface impoundment in its place.
- Convert the disposal surface impoundment to a new composite-lined storage impoundment.<sup>32</sup>
- Close the disposal surface impoundment and convert to dry handling operations.
- Make no changes to the operation of the disposal surface impoundment.

Consistent with the 2015 methodology, described in Section 9.4.1 of the 2015 TDD, the EPA developed a method to use the output analysis of the CCR rule to predict which of the four potential operational changes would likely occur at each coal-fired power plant that operates bottom ash disposal impoundments under the CCR rule, see Table 5-8.

**Table 5-8. ELG Bottom Ash Baseline Changes Accounting for CCR Rule**

CCR Rule Decision	Adjustment to ELG Baseline	Effect on ELG Costs <sup>a</sup>	Effect on ELG Loadings <sup>a</sup>
New disposal impoundment	No changes	No changes	No changes

<sup>31</sup> For the CCR rule, a disposal surface impoundment is generally defined as an impoundment that is not dredged and all CCRs are left in place in perpetuity.

<sup>32</sup> For the CCR rule, a storage impoundment is generally defined as an impoundment that is periodically dredged and has its CCR disposed elsewhere such that it can continue operating indefinitely.

**Table 5-8. ELG Bottom Ash Baseline Changes Accounting for CCR Rule**

CCR Rule Decision	Adjustment to ELG Baseline	Effect on ELG Costs <sup>a</sup>	Effect on ELG Loadings <sup>a</sup>
New storage impoundment	Plant dredges bottom ash from impoundment and disposes of it.	Plant incurs capital and O&M costs for the bottom ash handling system, but does not incur transport/disposal costs.	No changes
Convert to dry handling	Plant operates a dry bottom ash handling or closed-loop recycle system for all generating units.	Plant incurs no bottom ash compliance costs. <sup>b</sup>	Plant has a baseline bottom ash loading of zero.
No decision	No changes	No changes	No changes

a – Changes described are compared to the costs and loads that would have been calculated if the EPA was not accounting for the CCR rule.

b – Plants that install remote mechanical drag systems to comply with the CCR rule may also incur costs to install a reverse osmosis system to treat a slipstream of the recirculating bottom ash transport water, as a way to remove dissolved solids and facilitate long-term operation of the system as a closed loop to comply with the bottom ash zero discharge requirements of the 2015 rule (i.e., baseline). There are other approaches that can also be used to remove dissolved solids from the bottom ash system without using reverse osmosis treatment, such as using the transport water as makeup water for the FGD system. Dissolved solids will also be removed from the system along with the bottom ash, which is wet as it is removed from the rMDS. As data become available on how specific plants comply with CCR, the EPA will update the compliance cost estimates as appropriate in future analyses.

### 5.3.2 Cost Methodology for Mechanical Drag System

The EPA estimated capital, O&M, and 3-year recurring costs associated with installing an MDS for all steam electric generating units equipped with wet bottom ash handling systems that discharge bottom ash transport water. The EPA used cost data from the 2015 rule to develop capital cost curves for on-site and off-site disposal as a function of generating unit capacity. The EPA developed O&M cost curves for on-site and off-site disposal as a function of the amount of wet bottom ash produced. The EPA also developed a separate set of cost curves for those plants currently operating a storage impoundment for their bottom ash rather than a disposal impoundment. Plants with storage impoundments periodically dredge the impoundment to remove the ash and haul it away for disposal or beneficial use rather than leaving the bottom ash in the impoundment for long-term disposal. Because these plants with storage impoundments already incur transport and disposal costs (see Table 5-8) as part of their current ash handling practices, the MDS cost curves for these plants do not include incremental transport and disposal costs.

The MDS capital cost curves account for the purchase and installation of conveyance equipment, a semi-dry bottom ash intermediate storage silo, and motors required to operate the system. They include the following components:

- Direct Capital Costs.
  - Purchased equipment (including fabricated equipment and process machinery).

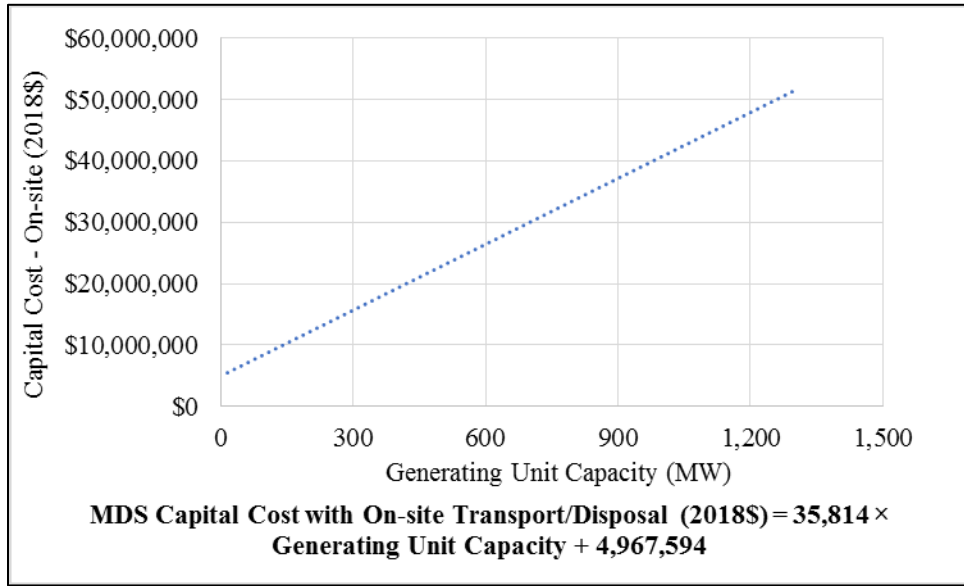
- Freight.
- Purchased equipment installation.
- Instrumentation and controls (installed).
- Piping (installed).
- Electrical (installed).
- Buildings (including services).
- Site preparation (including land purchase, if required).
- Indirect Capital Costs.
  - Engineering and supervision.
  - Construction expenses.
  - Contractor’s fees.
  - Contingency.

MDS O&M curves account for the operation and maintenance of the MDS system, intermediate storage, bottom ash disposal for plants with on-site or off-site landfill disposal, as well as cost savings associated with elimination of wet sluicing operations, and include the following cost elements:

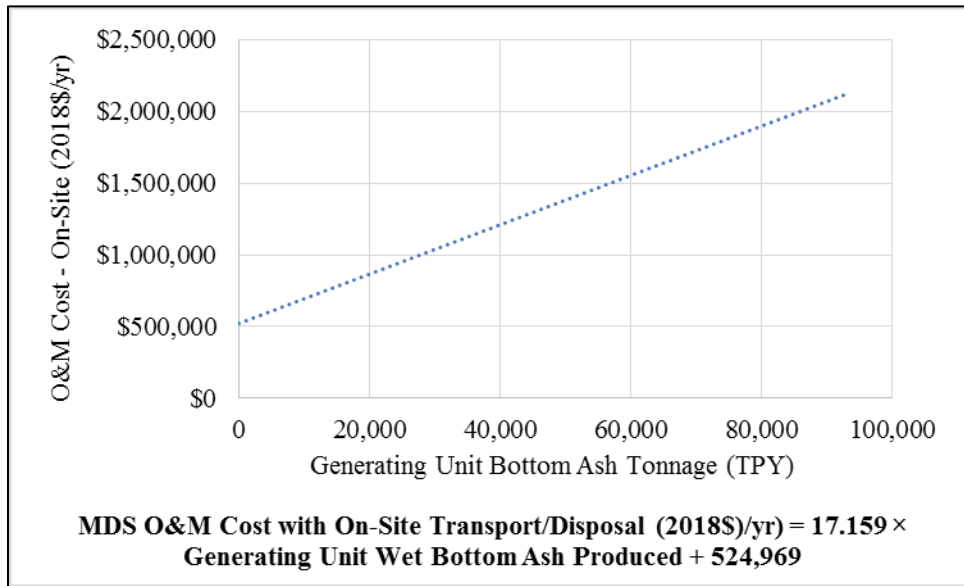
- Conveyance Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Energy.
- Intermediate Storage Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Energy.
- Bottom Ash Disposal Costs.
- Wet Sluicing O&M Cost Savings.
  - Operating labor.
  - Maintenance materials and labor.
  - Energy.

#### *Plant-Level Capital and O&M Costs*

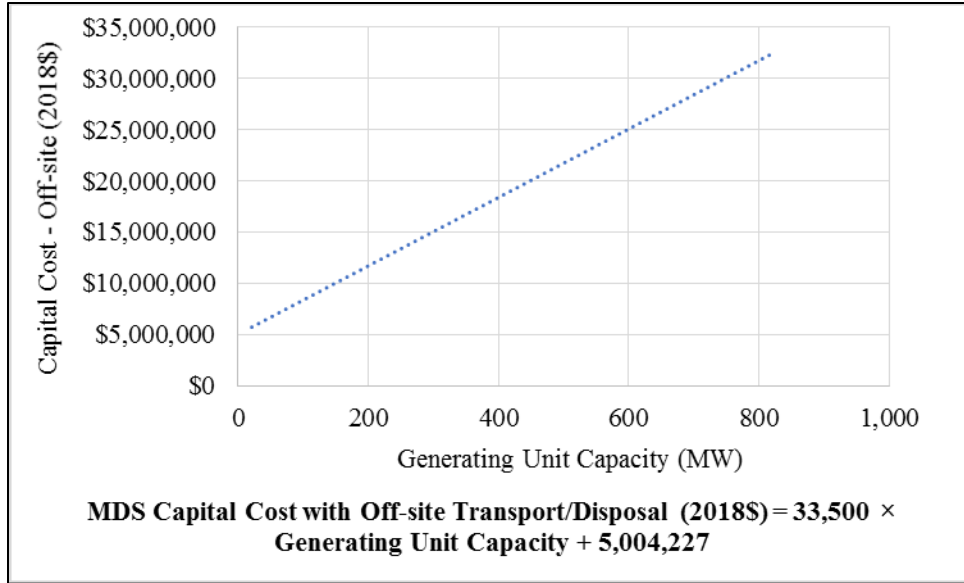
Using the 2015 rule cost data and the bottom ash production data, the EPA generated cost curves for estimating unit-level MDS capital and O&M costs as a function of unit-level capacity and unit-level bottom ash production, respectively. Because costs are affected by the solids disposal location (i.e., on-site landfill or off-site transportation and disposal), the EPA generated a set of cost curves for each transportation and disposal method (see Figure 5-21 and Figure 5-23 for capital costs and Figure 5-22 and Figure 5-24 for O&M costs).



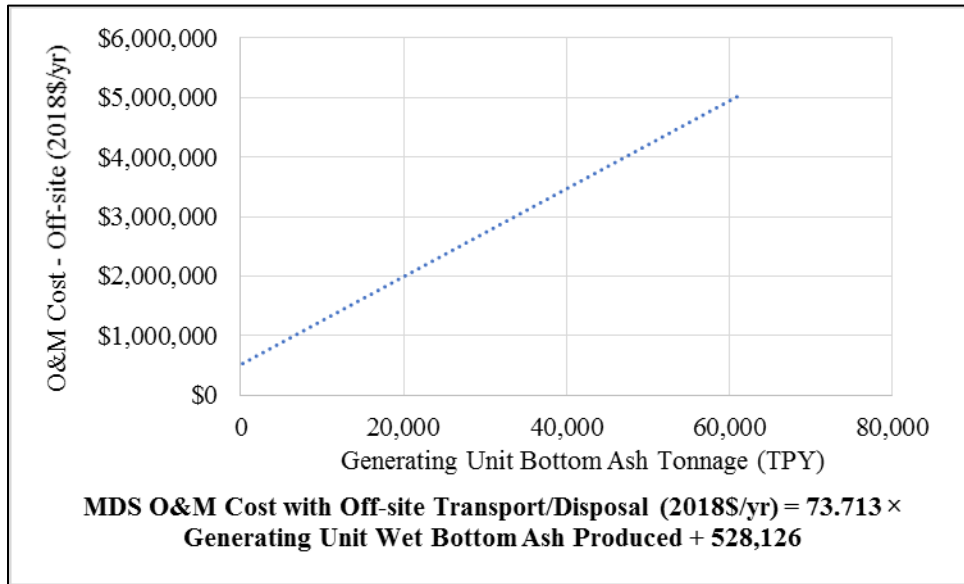
**Figure 5-21. MDS Capital Cost Curve – On-site Transport/Disposal**



**Figure 5-22. MDS O&M Cost Curve – On-site Transport/Disposal**

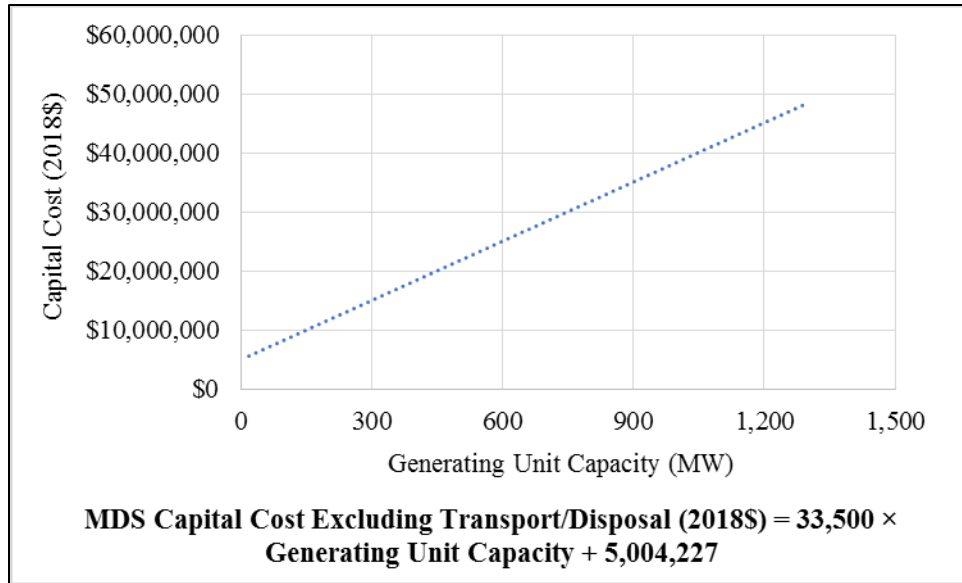


**Figure 5-23. MDS Capital Cost Curve – Off-site Transport/Disposal**



**Figure 5-24. MDS O&M Cost Curve – Off-site Transport/Disposal**

Plants currently operating a CCR impoundment for bottom ash storage already incur costs for transporting and disposing bottom ash. Therefore, these plants do not incur incremental costs for transport and disposal under the proposed rule. The EPA calculated the unit-level MDS capital costs for plants operating CCR storage impoundments using the cost curve in Figure 5-25 below.



**Figure 5-25. MDS Capital Cost Curve – Excluding Transport/Disposal**

The EPA estimated MDS O&M costs for plants operating CCR impoundments for bottom ash storage using the average compliance cost from the 2015 rule Equation 5-12.

$$\text{MDS O\&M Cost Excluding Transport/Disposal (2018\$/yr)} = \$534,000$$

Equation 5-12

In addition, plants that currently discharge bottom ash transport water to a POTW receive a cost savings for eliminating bottom ash transport water discharges and ceasing discharges to the POTW. The EPA identified two plants from the Steam Electric Survey data that discharge bottom ash wastewater to a POTW and are expected to install an MDS. Using the POTW-specific rate structures, the EPA estimated the annual costs incurred by these plants for discharging to a POTW and deducted these annual costs (ERG, 2019i).

For each generating unit, the EPA selected the MDS capital and O&M cost curves based on the identified bottom ash transportation and disposal method at the plant using the landfill data described in Section 5.3.1. The EPA calculated the MDS capital and O&M compliance costs using the generating-unit-specific data and corresponding equations.

### *Recurring Costs*

The EPA estimated 3-year recurring costs associated with MDS drag chain replacement. The drag chain is the component of the system that drags the bottom ash from the water bath, up the incline to intermediate storage. Based on vendor data, this chain should be replaced every three years and costs approximately \$206,000. See Equation 5-13.<sup>33</sup>

<sup>33</sup> The generating unit can continue to operate during replacement of the drag chain components.

$$\text{MDS 3-Year Cost (2018\$)} = \$206,000$$

Equation 5-13

The EPA calculated plant-level MDS costs by summing the MDS capital, MDS O&M, and 3-year recurring costs for all units at each plant.

### **5.3.3 Cost Methodology for Remote Mechanical Drag Systems Operated to Achieve Zero Discharge (No Purge)**

The EPA estimated capital, O&M, and 5-year recurring costs associated with installing a rMDS for all plants except those currently operating an rMDS system. The EPA used cost data from the 2015 rule to develop capital cost curves for on-site and off-site disposal as a function of generating unit capacity. The EPA developed O&M cost curves for on-site and off-site transport and disposal as a function of the amount of wet bottom ash produced. The EPA also developed a separate set of cost curves for those plants currently operating a storage impoundment for their bottom ash, rather than a disposal impoundment. Plants with storage impoundments periodically dredge the impoundment to remove the ash and haul it away for disposal or beneficial use, rather than leaving the bottom ash in the impoundment for long-term disposal. Because these plants with storage impoundments already incur transport and disposal costs as part of their current ash handling practices, see Table 5-8, the rMDS cost curves for these plants do not include incremental transport and disposal costs.

The rMDS capital cost curves account for the purchase and installation of the rMDS unit equipment, a semi-dry bottom ash intermediate storage silo, a chemical feed system to control recycle pH and suspended solids, and recycle pumps. The capital cost curves include the following components:

- Direct Capital Costs.
  - Purchased equipment (including fabricated equipment and process machinery).
  - Freight.
  - Purchased equipment installation.
  - Instrumentation and controls (installed).
  - Piping (installed).
  - Electrical (installed).
  - Buildings (including services).
  - Yard improvements.
  - Service facilities (installed).
  - Land (if purchase is required).
- Indirect Capital Costs.
  - Engineering and supervision.



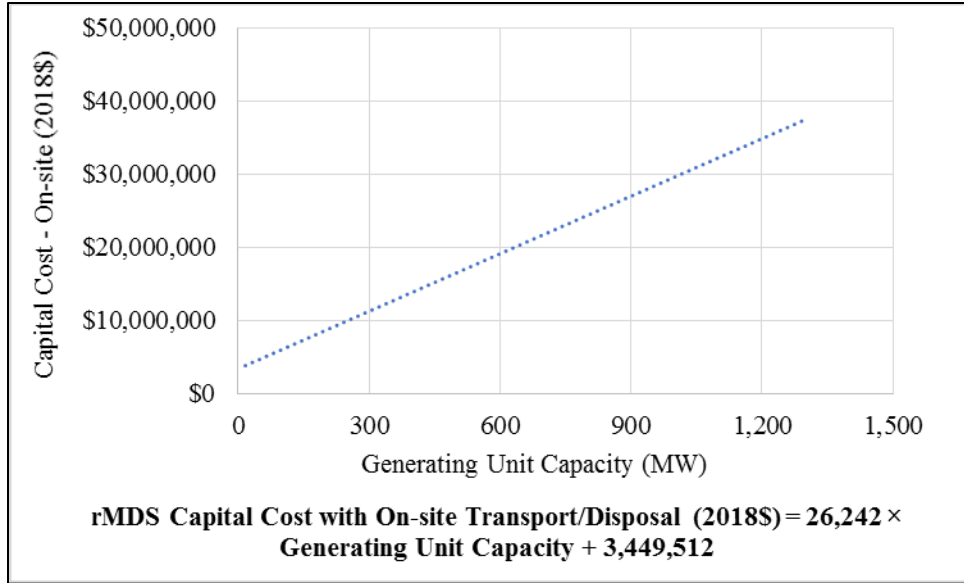
- Construction expenses.
- Contractor’s fees.
- Contingency.

The rMDS O&M cost curves account for the operation and maintenance of the rMDS, intermediate storage, and the cost to purchase acid or caustic for the chemical feed system for pH control. The chemical feed system could also be used to add polymers to enhance removal of suspended solids, if warranted. The rMDS O&M cost curves include the following components:

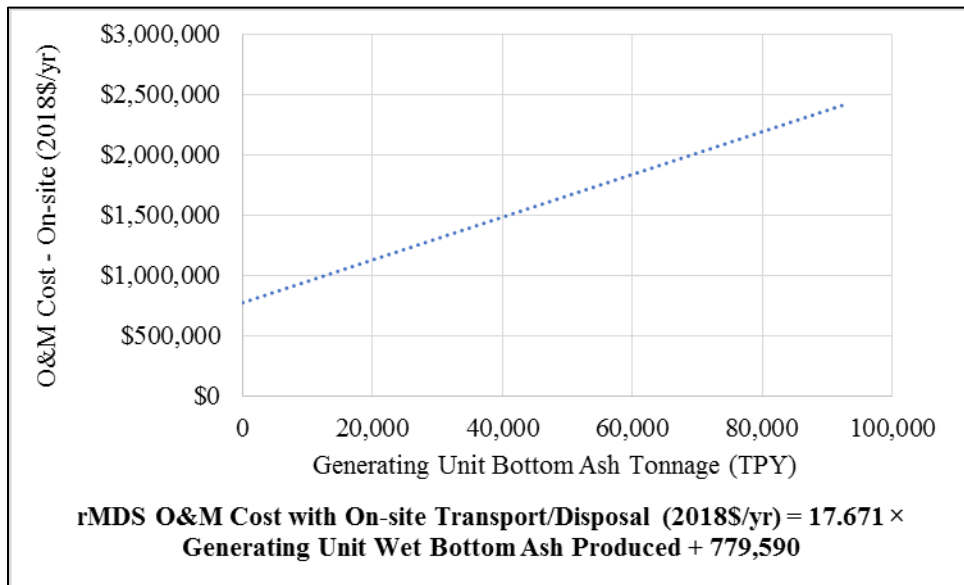
- Conveyance Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Energy.
- Chemical Purchase Cost.
- Intermediate Storage Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Energy.
- 5-year maintenance cost associated with the wear-plate.

#### *Plant-Level Capital and O&M Cost for Remote Mechanical Drag Systems*

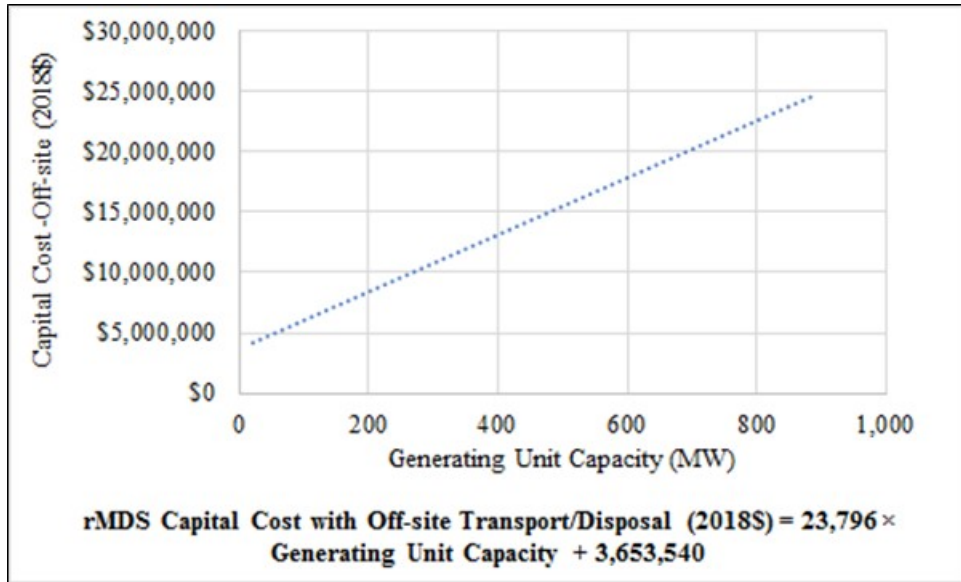
Using the 2015 rule cost data and the bottom ash production data, the EPA generated cost curves for estimating unit-level rMDS capital and O&M costs as a function of unit-level capacity and unit-level bottom ash production, respectively. Because costs are affected by the solids disposal location (i.e., on-site landfill or off-site transportation and disposal), the EPA generated a set of cost curves for each transportation and disposal method (see Figure 5-26 and Figure 5-28 for capital costs and Figure 5-27 and Figure 5-29 for O&M costs).



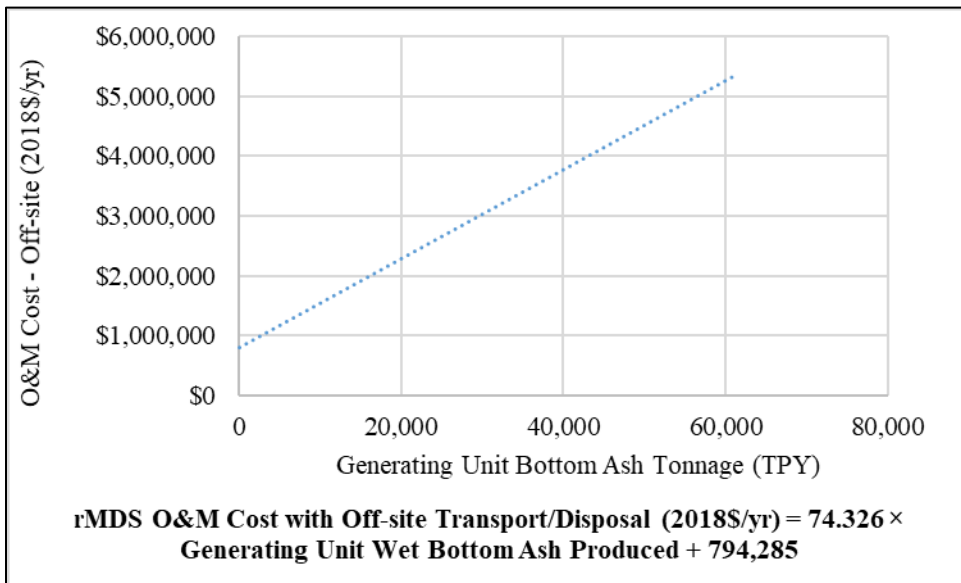
**Figure 5-26. rMDS Capital Cost Curve – On-site Transport/Disposal**



**Figure 5-27. rMDS O&M Cost Curve – On-site Transport/Disposal**

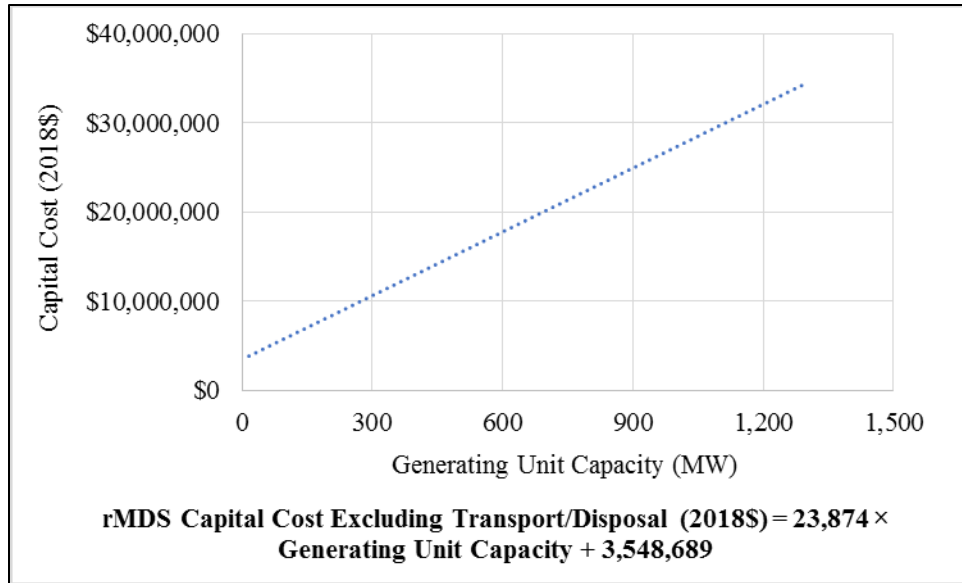


**Figure 5-28. rMDS Capital Cost Curve – Off-site Transport/Disposal**



**Figure 5-29. rMDS O&M Cost Curve – Off-site Transport/Disposal**

As stated previously in Section 5.3.2, plants currently operating a CCR impoundment already incur costs for transporting and disposing bottom ash. Therefore, these plants do not incur incremental costs for rMDS transport and disposal under the proposed rule. The EPA calculated the unit-level MDS capital costs for plants operating CCR storage impoundments using the cost curve in Figure 5-30 below.



**Figure 5-30. rMDS Capital Cost Curve – Excluding Transport/Disposal**

The EPA estimated rMDS O&M costs for plants operating CCR impoundments using the average compliance cost from the 2015 rule (Equation 5-14).

$$\text{Total rMDS O\&M Cost Excluding Transport/Disposal (2018\$/yr)} = \$804,000$$

Equation 5-14

For each generating unit in the costed population, the EPA selected the rMDS capital and O&M cost curves based on the identified bottom ash transportation and disposal method at the plant using the landfill data described in Section 5.3.1. The EPA calculated the rMDS capital and O&M compliance costs using the generating unit-specific data and corresponding equations.

#### *Additional Zero Discharge Costs*

The cost methodology for all rMDS systems includes chemical addition equipment to manage pH of the transport water so that potential corrosion or scaling is minimized, and to allow for polymer addition if needed to enhance removal of suspended solids. For the zero discharge technology option, the EPA has also estimated costs for plants to install more robust treatment should it be necessary to prevent the buildup of dissolved solids to levels that may interfere with effectively controlling corrosion and scale formation by the chemical addition processes. This additional treatment entails the use of reverse osmosis to treat a slipstream of transport water. The data in the record indicates that most plants would not experience such TDS-related interferences or that managing alkalinity would resolve potential issues and obviate the need for RO treatment. However, since the EPA does not have sufficient plant-specific data to determine which plants may need RO treatment, the EPA's cost methodology assumes that all new and current rMDS systems would install RO treatment to ensure the plant could manage the closed-loop recycle for the bottom ash transport water.

The treated effluent from the RO unit is of higher quality than other makeup water sources used at power plants; therefore, plants are likely to reuse the treated effluent within the bottom ash handling system. Based on industry-provided data, the EPA estimated the daily slipstream flow rate to be 10 percent of the primary active wet bottom ash system volume (i.e., the plant-level volume associated with the bottom ash hoppers, rMDS, sluice pipes, and surge tanks, but not installed spares, redundancies, maintenance tanks, or other secondary bottom ash system equipment not used on a daily or near-daily basis).

The EPA identified the population of plants likely to install the rMDS system as those plants that (1) have already installed rMDS; (2) previously provided information indicating that MDS is not a viable retrofit option because of insufficient height under the boiler or other boiler house impediment; or (3) the cost to install rMDS is lower than the cost for MDS. The EPA then calculated the additional capital costs (including equipment, instrumentation, and installation) and O&M costs associated with the handling and treatment of a recycled slipstream at the plant level using Equation 5-15 and Equation 5-16. The EPA calculated these additional costs at the plant level because plants with multiple rMDS units will treat all bottom ash transport water slipstreams generated at the plant with one treatment system (ERG, 2019i)

$$\text{Additional Zero Discharge rMDS Capital Costs} = \text{Total RO Capital Costs} + \text{Total Tank/Pipe/Pump Capital Costs}$$

Equation 5-15

$$\text{Additional Zero Discharge rMDS O\&M Costs} = \text{Total RO O\&M Costs} + \text{Total Tank/Pipe/Pump O\&M Costs}$$

Equation 5-16

### *RO Capital and O&M Costs*

To calculate the plant-level RO capital and O&M costs, the EPA first estimated the total volume of the rMDS systems expected to be operating at the plant, based on the plant-level capacity and information provided by the industry (ERG, 2019i). For plants with a total capacity less than or equal to 200 MW, the EPA estimated a total rMDS volume of 175,000 gallons. For plants with a total generating capacity greater than 200 MW, the EPA estimated total rMDS volume using Equation 5-17.

$$\text{Total rMDS Volume (gal)} = 347.29 \times \text{Plant-Level Capacity (MW)} + 146,398$$

Equation 5-17

Where:

$$\text{Plant-Level Capacity} = \text{The sum of all plant generating unit capacities flagged for bottom ash compliance costs (in MW).}$$

Based on information provided by industry, the EPA estimated the daily flow of the slipstream sent to RO treatment prior to recycle to be 10 percent of the total rMDS volume (Equation 5-18).

$$\text{Slipstream Flow (GPM)} = (\text{Total rMDS Volume} \times 0.1/\text{day}) / 24 \text{ hr /day} / 60 \text{ min/hr}$$

Equation 5-18

Where:

$$\text{Total rMDS Volume} = \text{Total volume of all rMDS expected to be operating the plant (in gallons).}$$

The EPA estimated plant-level RO capital and O&M costs as a function of the slipstream flow rate using the Equation 5-19 and Equation 5-20.

$$\text{Total RO Capital Cost (2018\$)} = 58,838 \times \text{Slipstream Flow (GPM)} + 2,298,650$$

Equation 5-19

$$\text{Total RO O\&M Cost (2018\$)} = \$0.01 \times \text{Slipstream Flow} \times 60 \text{ minutes/hour} \times 24 \text{ hr/day} \times 365 \text{ days/year}$$

Equation 5-20

Where:

$$\text{Slipstream Flow} = \text{Daily flow rate of rMDS slipstream (in GPM) (see Equation 5-18).}$$

The EPA then assigned a portion of the total RO capital and O&M costs to each generating unit by multiplying the plant-level costs by the ratio of generating unit capacity to plant-level capacity in MW.

#### *Surge Tank, Pipe, and Pump Costs*

The EPA estimated the total capital costs associated with operating the surge tank, pumps, and piping needed to hold and recirculate RO distillate, or any bottom ash transport water from a maintenance or precipitation event, back to the plant for reuse, based on the 2015 rule cost methodology or information provided by tank vendors, using Equation 5-21 and Equation 5-22.

$$\text{Total Tank/Pipe/Pump Capital Costs} = \text{Total Purchased Equipment Cost} + \text{Direct Capital Costs} + \text{Indirect Capital Costs}$$

Equation 5-21

$$\text{Total Purchased Equipment Costs} = \text{Tank Cost} + \text{Pipe Cost} + \text{Pump Cost}$$

Equation 5-22

The EPA estimated the surge tank purchased equipment costs using the relationship between tank size and cost, developed from vendor-provided data, and adjusted the cost basis from 2011 dollars to 2018 dollars using RSMMeans Historical Cost Indices (Gordian, 2018).

To estimate tank cost, the EPA first estimated the size of the required surge tank using Equation 5-23. Tank size is based on the largest generating unit at the plant (defined by capacity in MW) and the expectation that only one generating unit will need to empty the bottom ash hopper at any one time. The EPA also accounted for an additional 50 percent capacity for the surge tank by multiplying the relationship by a tank sizing factor of 1.5.

$$\text{Tank Size (gallons)} = 63 \times \text{Unit Capacity} \times \text{Tank Sizing Factor} \quad \text{Equation 5-23}$$

Where:

$$\begin{aligned} \text{Unit Capacity} &= \text{Capacity of the generating unit (in MW).} \\ \text{Tank Sizing Factor} &= 1.5. \end{aligned}$$

The EPA then estimated the cost as a function of tank size based on information provided by tank vendors. For tanks less than 50,000 gallons in size, see Equation 5-24.

$$\text{Tank Cost (2018\$)} = (2.16 \times \text{Tank Size} + 22.7 \times (\text{Tank Size} \times 1.5)^{0.548}) \times (\text{2018 Cost Index} / \text{2011 Cost Index}) \quad \text{Equation 5-24}$$

Where:

$$\begin{aligned} \text{Tank Size} &= \text{Size of the surge tank (in gallons)} \\ \text{2011 Cost Index} &= 185 \\ \text{2018 Cost Index} &= 215.8 \end{aligned}$$

For tanks greater than 50,000 gallons in size, see Equation 5-25:

$$\text{Tank Cost (2018\$)} = (3.45 \times \text{Tank Size} + 22.7 \times (\text{Tank Size} \times 1.5)^{0.548}) \times (\text{2018 Cost Index} / \text{2011 Cost Index}) \quad \text{Equation 5-25}$$

Where:

$$\begin{aligned} \text{Tank Size} &= \text{Size of surge tank (in gallons)} \\ \text{2011 Cost Index} &= 185 \\ \text{2018 Cost Index} &= 215.8 \end{aligned}$$

The EPA developed a relationship between pump equipment costs and bottom ash slipstream flow, using vendor-provided information, to estimate plant-specific pump costs, then adjusted the

cost basis from 2011 dollars to 2018 dollars using RSMeans Historical Cost Indices (Gordian, 2018). Pump costs include the cost of four pumps: one to pump water from the hopper to the tank plus one spare, and one to return water back to the hopper plus one spare.

The EPA first estimated the flow from the surge tank using Equation 5-26.

$$\text{Flow} = \text{Tank Size} / (60 \text{ min/hr} \times 5 \text{ hrs/day})$$

Equation 5-26

Where:

$$\text{Tank Size} = \text{Size of the surge tank (in gallons).}$$

The EPA then calculated the pump as a function of this flow, using Equation 5-27.

$$\text{Pump Cost (2018\$)} = (2,940 \times \ln(\text{Flow}) - 1,957) \times 4.16 \times (\text{2018 Cost Index} / \text{2011 Cost Index})$$

Equation 5-27

Where:

$$\begin{aligned} \text{2011 Cost Index} &= 185. \\ \text{2018 Cost Index} &= 215.8. \\ \text{Flow} &= \text{Tank size (in gallons).} \end{aligned}$$

The EPA estimated the cost of 2,640 feet of piping using an assumed distance of 0.25 miles between the surge tank and bottom ash hopper: \$37,000 (2018\$).

The EPA estimated the total plant-level direct capital costs by multiplying the sum of the purchased equipment costs for the tank, pumps, and piping by 2, using Equation 5-28.

$$\text{Direct Capital Costs} = 2 \times \text{Total Purchased Equipment Cost}$$

Equation 5-28

The EPA estimated the indirect capital costs by multiplying the sum of the total purchased equipment and direct capital costs by 0.43, using Equation 5-29.

$$\text{Indirect Capital Costs} = 0.43 \times (\text{Total Purchased Equipment Cost} + \text{Direct Capital Costs})$$

Equation 5-29

The EPA calculated plant-level O&M costs associated with operating the surge tank, pumps, and pipe. Total O&M costs include the cost of energy to operate the pumps and the maintenance cost associated with the surge tank, pumps, and pipes.



$$\text{Total Tank/Pump/Pipe O\&M Costs} = \text{Energy Cost} + \text{Maintenance Cost}$$

Equation 5-30

To calculate the energy cost, the EPA first estimated the annual energy requirement to operate the pumps, based on the 2015 rule cost methodology, using Equation 5-31.

$$\text{Annual Energy Requirement (kWh/yr)} = 145 \times \text{Flow} + 13,200$$

Equation 5-31

Where

Flow = Daily flow rate from the surge tank (in GPM) (see Equation 5-26).

The EPA then estimated the cost of operating the pumps using the pump energy requirement and the national energy cost per kWh, based on data reported by the U.S. Energy Information Administration (EIA) (U.S. DOE, 2011), in 2018 dollars, using Equation 5-32.

$$\text{Energy Cost (2018\$)} = \text{National Energy Cost} \times \text{Annual Energy Requirement}$$

Equation 5-32

Where:

Annual Energy Requirement = Annual energy requirement to operate pumps (in kWh/yr) (see Equation 5-31).

National Energy Cost = \$0.0485/kWh (in 2018\$).

The EPA developed a relationship between bottom ash slipstream flow and the cost to maintain the surge tank, pumps, and piping to estimate total maintenance costs.

$$\text{Maintenance Cost (2018\$)} = 457 \times \text{Flow}$$

Equation 5-33

Where:

Flow = Daily flow rate from the surge tank (in GPM) (see Equation 5-26).

### *Recurring Costs*

The EPA estimated 5-year recurring costs associated with rMDS drag chain replacement. The drag chain is the component of the system that drags the bottom ash from the water bath, up the incline to intermediate storage; based on vendor data this chain should be replaced every five years and costs approximately \$206,000 (Equation 5-34).

$$\text{rMDS 5-Year Cost (2018\$)} = \$206,000$$

Equation 5-34

The EPA calculated plant-level MDS costs by summing the rMDS capital, rMDS O&M, and 5-year recurring costs for all units at each plant.

#### **5.3.4 Cost Methodology for Remote Mechanical Drag Systems Operated with a Purge**

As discussed in Section 5.3.3 above, the EPA estimated capital, O&M, and 5-year recurring costs associated with installing an rMDS for all plants except those currently operating an rMDS system. The EPA anticipates that operating rMDS with a purge stream, rather than as zero discharge, will prevent plants from experiencing a buildup of dissolved solids to levels that may interfere with effective corrosion and scale control, and subsequently, the need for RO treatment of a slipstream. Therefore, to estimate compliance costs for the purge option, the EPA included all zero discharge option rMDS costs except costs classified as additional zero discharge costs (see Additional Zero Discharge Costs). The EPA included all capital and O&M costs (see Plant-Level Capital and O&M Cost for Remote Mechanical Drag Systems) as well as recurring costs (see Recurring Costs) associated with rMDS for this option.

#### **5.3.5 Bottom Ash Management Cost Methodology**

The EPA identified several plants that operate bottom ash wet-sluicing systems as closed-loop systems. These plants did not report any discharge of bottom ash transport water in the Steam Electric Survey. However, based on other information in the survey responses, the EPA determined that these plants have retained the capability to discharge bottom ash transport water from emergency outfalls. Therefore, the EPA estimated additional costs associated with eliminating the potential future discharge of bottom ash transport water, which survey data confirm is not typical practice. The EPA estimated a one-time cost associated with consulting an engineer to eliminate the need and the capacity to discharge bottom ash transport water via emergency outfalls—thereby achieving a completely closed bottom ash recycle system. The one-time cost includes contractor labor and travel. For each bottom ash management plant, the EPA estimated a one-time cost of \$26,400, in 2018 dollars.

In addition to one-time costs, the EPA estimated capital and O&M costs for a chemical feed system. This additional cost was estimated (although it may not be needed) so that plants would have a system in place to regulate pH of the recycled bottom ash transport water. Using the 2015 rule cost data and EPA's methodology for estimating rMDS chemical feed system costs, the EPA estimated capital and O&M costs associated with operating a chemical feed system at bottom ash management plants and converted the cost to 2018 dollars.

#### **5.3.6 Bottom Ash BMP Plan Cost Methodology**

For plants operating one or more units with a 2016 EIA net generation of less than or equal to 876,000 MWh, the EPA estimated costs associated with the development and implementation of a BMP plan to recycle as much bottom ash transport water determined to be achievable. These costs include (1) the initial development of the BMP plan, (2) capital and operation and

maintenance (O&M) costs for pumps and piping associated with any recirculation, and (3) the annual review of and revision to the BMP plan.

### *One-time Costs*

The EPA calculated the one-time cost for developing the BMP plan using Equation 5-35. The one-time cost includes the cost of an outside contractor<sup>34</sup> reviewing current operations and developing a BMP plan, which includes four weeks on site at the plant, and plant review and acceptance of plan.

$$\begin{aligned} \text{BMP Plan One-Time Cost (2018\$)} &= \text{Contractor Labor Cost} \\ &+ \text{Contractor Travel Cost} + \text{Plant Review Cost} \end{aligned} \quad \text{Equation 5-35}$$

$$\begin{aligned} \text{Contractor Labor Cost (2018\$)} &= \text{Number of Hours} \\ &\times \text{Contractor Rate} = \$33,600 \end{aligned} \quad \text{Equation 5-36}$$

Where:

- Number of Hours = EPA estimated number of hours for the contractor to develop the BMP plan, 280 hours.
- Contractor Rate = EPA estimate of the contractor rate, \$120/hr (in 2018\$).

$$\begin{aligned} \text{Contractor Travel Cost (2018\$)} &= (\text{Number of Travel Days} \times \text{Hotel Cost} \times \text{Escalation Rate}) + \\ &(\text{Number of Travel Days} \times \text{Food Cost}) + (\text{Number of Travel Weeks} \times \text{Car Rental Cost}) + \\ &(\text{Number of Trips} \times \text{Airfare Costs}) = \$6,549 \end{aligned} \quad \text{Equation 5-37}$$

Where:

- Number of Travel Days = Number of work days in a four-week period, 24 days.
- Hotel Cost = The 2018 federal per diem rate for hotels based on standard continental United States (CONUS) rates, \$93/day (in 2018\$).
- Escalation Rate = An escalation factor to account for potential increases in hotel costs based on location and hotel taxes, 1.40 (i.e., 25 percent for potential increases, 15 percent for hotel taxes).

<sup>34</sup> Some plants may incur different costs by using company environmental or operations staff instead of an outside contractor. For the purpose of this cost methodology, the EPA assumed that plants would incur costs associated with an outside contractor.

Food Cost	=	The 2018 federal per diem rate for meals and incidentals based on standard CONUS rates, \$51/day (in 2018\$).
Number of Travel Weeks	=	Number of weeks on site, 4.
Car Rental Cost	=	Estimate of a full-size rental car cost per week, \$250 (in 2018\$).
Number of Trips	=	Estimated number of trips required, 2.
Airfare Costs	=	Estimate of the round-trip airfare for the contractor to travel to the plant, \$600 (in 2018\$).

$$\text{Plant Review Cost (2018\$)} = \text{Number of Hours} \times \text{Environmental Coordinator Labor Rate} = \$2,091$$

Equation 5-38

Where:

Number of Hours	=	EPA estimated number of hours for the plant to review and accept the plan, 48 hours.
Environmental Coordinator Labor Rate	=	\$43.56/hr (in 2018\$).

### *Capital Costs for Piping and Pumps*

The EPA calculated the capital and O&M costs associated with piping and pumps to accommodate recycling bottom ash transport water from the bottom ash impoundment or dewatering bins back to the bottom ash sluicing system. For the purpose of the BMP cost estimate, the EPA calculated average capital and O&M costs using Equation 5-39.

$$\text{Total Recycle Equip Capital (2018\$)} = \text{Total Pipe Capital Costs (2018\$)} + \text{Total Pump Capital Costs (2018\$)} = \$295,200$$

Equation 5-39

The EPA assumed that 2,472 feet of piping are required (based on the average distance bottom ash transport water was sluiced to an impoundment reported in the Steam Electric Survey) and calculated the median piping costs to be \$148,700 (2018\$).

The EPA assumed that two pumps are required, one for pumping the water from the bottom ash impoundment back to the bottom ash sluice system, and one for redundancy. Based on the maximum bottom ash sluice flow rates within steam electric power generating industry population, the EPA calculated a pump capital cost of \$146,500 (2018\$).

The EPA estimated the total annual O&M costs associated with pumping the bottom ash transport water back to the bottom ash sluice system. Only one pump will be operating at a time and calculated a total recycled equipment O&M cost of \$2,200 (2018\$) per year.

#### *Annual Costs for BMP Review*

The EPA calculated the annual costs associated with reviewing the BMP plan and making any updates or revisions to the plan, as necessary. The annual costs include the cost of an outside contractor reviewing the BMP and incorporating revisions, which includes a one-day site visit to the plant, and plant review and acceptance using Equation 5-40.

$$\begin{aligned} \text{BMP Plan Annual Cost (2018\$/yr)} &= \text{Annual Contractor Labor Cost} \\ &+ \text{Annual Contractor Travel Cost} + \text{Plant Annual Review Cost} \end{aligned}$$

Equation 5-40

$$\text{Annual Contractor Labor Cost (2018\$/yr)} = \text{Number of Hours} \times \text{Contractor Rate} = \$4,800$$

Equation 5-41

Where:

- Number of Hours = EPA estimated number of hours for the contractor to complete the BMP, 40.
- Contractor Rate = EPA estimate of the contractor rate, \$120/hr (in 2018\$).

$$\begin{aligned} \text{Annual Contractor Travel Cost (2018\$/yr)} &= (\text{Number of Travel Days} \times \text{Hotel Cost} \times \text{Escalation} \\ &\text{Rate}) + (\text{Number of Travel Days} \times \text{Food Cost}) + (\text{Number of Travel Weeks} \times \text{Car Rental Cost}) + \\ &(\text{Number of Trips} \times \text{Airfare Costs}) = \$831 \end{aligned}$$

Equation 5-42

Where:

- Annual Contractor Travel Cost = The annual travel cost for a contractor to visit the plant to review the BMP Plan once per year.
- Number of Travel Days = Number of work days required for travel, 1 day.
- Hotel Cost = The 2018 federal per diem rate for hotels based on standard continental United States (CONUS) rates, \$93/day (in 2018\$).
- Escalation Rate = An escalation factor to account for potential increases in hotel costs based on location and hotel taxes, 1.40 (i.e., 25 percent for potential increases, 15 percent for hotel taxes).

Food Cost	=	The 2018 federal per diem rate for meals and incidentals based on standard CONUS rates, \$51/day (in 2018\$).
Number of Travel Weeks	=	Number of weeks on-site, 0.2.
Car Rental Cost	=	Estimate of a full-size rental car cost per week, \$250 (in 2018\$).
Number of Trips	=	Estimated number of trips required, 1.
Airfare Costs	=	Estimate of the round-trip airfare for the contractor to travel to the plant, \$600 (in 2018\$).

$$\text{Plant Annual Review Cost (2018\$/yr)} = \text{Number of Hours} \times \text{Environmental Coordinator Labor Rate} = \$697$$

Equation 5-43

Where:

Plant Annual Review Cost	=	The annual cost for the plant to review the BMP plan annually (in 2018\$ per year).
Number of Hours	=	EPA estimated annual number of hours for the plant to review the plan, 16 hours.
Environmental Coordinator Labor Rate	=	\$43.56/hr (in 2018\$).

### 5.3.7 Methodology for Estimating Cost Savings from Ceasing Use of Surface Impoundments

When plants install bottom ash handling systems that no longer require the use of surface impoundments, they will experience some cost savings associated with ceasing operations of these bottom ash surface impoundment(s). This decrease in impoundment operations costs will offset the cost to operate the new treatment system, to some degree. The EPA estimated the annual O&M and recurring costs associated with on-site impoundments and subtracted these costs from the estimated compliance costs for the technologies described above in this section, consistent with the 2015 methodology. The impoundment operating cost savings quantified by the EPA include costs associated with the following:

- Wastewater transport system (i.e., pipelines, vacuum source) pumping the wastewater from the bottom ash hopper to the impoundment.
- Impoundment site (i.e., general operation of the impoundment and inspections).
- Wastewater treatment system (e.g., pH control).

- Water recycle system at the impoundment (if applicable).
- Bottom ash earthmoving costs (e.g., front-end loader, removing/stacking combustion residual materials at the impoundment site).

The EPA used Steam Electric Survey data to identify plants that have at least one impoundment containing bottom ash transport wastewater and not designated as retired or planned. Where the EPA had data indicating plants had installed a dry or closed-loop bottom handling systems since the 2015 rule, the EPA anticipated these plants no longer operate an impoundment for bottom ash handling. The EPA also anticipates that plants whose impoundments are expected to close due to CCR rule requirements will not use impoundments for bottom ash handling. The EPA estimated plant-level costs for operating impoundments based on the total amount of bottom ash solids currently handled wet at the plant. The EPA estimated the total bottom ash impoundment O&M cost savings using Equation 5-44.

$$\text{Total Bottom Ash Impoundment O\&M Cost Savings (2018\$/yr)} = (\text{Bottom Ash Impoundment Operating Cost Savings} + \text{Bottom Ash Earthmoving Cost Savings}) \times (\text{2018 Cost Index} / \text{2010 Cost Index})$$

Equation 5-44

Where:

Bottom Ash Impoundment Operating Cost Savings	=	Total impoundment operating cost savings (in 2010\$) see Equation 5-47.
Bottom Ash Earthmoving Cost Savings	=	O&M cost associated with the earthmoving equipment required (in 2010\$) see Equation 5-49.
2010 Cost Index	=	183.5.
2018 Cost Index	=	215.8.

#### *Bottom Ash Impoundment Operating Annual Cost Savings*

The EPA estimated the bottom ash impoundment operating cost savings by first calculating the plant MW factor using Equation 5-45 and the plant-specific unitized cost using Equation 5-46.

$$\text{Plant MW Factor} = 7.569 \times (\text{Plant Size})^{-0.32}$$

Equation 5-45

Where:

Plant Size = Plant size (in MW). The plant nameplate capacity for only those generating units in the bottom ash costed population.

$$\text{Plant-Specific Unitized Cost} = (\text{Impoundment Operating Unitized Cost}) \times (\text{Plant MW Factor})$$

Equation 5-46

Where:

Plant-Specific Unitized Cost = The plant-specific cost to operate a front-end loader (in 2010\$/ton).

Impoundment Operating Unitized Cost = The 2010 unitized annual cost to operate a combustion residual impoundment. The EPA used the unitized cost value \$7.35 per ton (in 2010\$).

Plant MW Factor = Factor to adjust combustion residual handling costs based on plant capacity.

Next, the EPA calculated the bottom ash impoundment operating cost savings by multiplying the plant-specific unitized cost using Equation 5-47 by the amount of bottom ash tonnage produced by the plant tons per year (TPY), discussed in Section 5.3.1.

$$\text{Bottom Ash Impoundment Operating Cost Savings (2010\$/yr)} = (\text{Plant-Specific Unitized Cost}) \times (\text{Plant Bottom Ash Tonnage})$$

Equation 5-47

Where:

Plant-Specific Unitized Cost = The plant-specific cost to operate a front-end loader (in 2010\$/ton).

Plant Bottom Ash Tonnage = The total bottom ash tonnage, dry basis, for each plant (in TPY). This value is calculated by multiplying the wet bottom ash generation rate (in TPY) for each generating unit, and then summing the generating unit-level values to the plant level.

#### *Bottom Ash Earthmoving Annual Cost Savings*

To calculate bottom ash earthmoving cost savings, the EPA first calculated the plant-specific front-end loader unitized cost by multiplying the plant MW factor and the front-end loader unitized cost using Equation 5-48.



$$\text{Plant-Specific Front-End Loader Unitized Cost (2010\$/ton)} = (\text{Front-End Loader 2010 Unitized O\&M Cost}) \times (\text{Plant MW Factor})$$

Equation 5-48

Where:

Front-End Loader 2010 Unitized O&M Cost = The 2010 unitized cost value that represents the operation and maintenance of the front-end loader used to redistribute ash at an impoundment. This value was calculated to be \$2.49 per ton (in 2010\$).

Plant MW Factor = Factor to adjust combustion residual handling costs based on plant capacity.

Next, the EPA calculated the bottom ash earthmoving cost savings by multiplying the plant-specific unitized cost using Equation 5-49 by the amount of bottom ash tonnage produced by the plant in TPY discussed in Section 5.3.1.

$$\text{Bottom Ash Impoundment Earthmoving Cost Savings} = (\text{Plant-Specific Front-End Loader Unitized Cost}) \times (\text{Plant Bottom Ash Tonnage})$$

Equation 5-49

Where:

Plant Bottom Ash Tonnage = The total bottom ash tonnage, dry basis, for each plant (in TPY). This value is calculated by multiplying the wet bottom ash generation rate in TPY for each generating unit, and then summing the generating-unit-level values to the plant level.

#### *Bottom Ash Earthmoving Recurring Costs*

The EPA calculated 10-year recurring costs associated with operating the earthmoving equipment (i.e., front-end loader) by determining the cost and average expected life of a front-end loader. The EPA determined the 2018 cost of the earthmoving equipment to be \$474,000 and assumed that the expected life of a front-end loader is 10 years.

#### **5.4 SUMMARY OF NATIONAL ENGINEERING COST FOR REGULATORY OPTIONS**

As described in the preamble, the EPA evaluated four regulatory options comprising various combinations of the treatment technologies considered for control of each wastestream. The EPA estimated different compliance costs for steam electric generating units with a specific steam electric power generating capacity, generating units with a specific net power generation, and “high-flow” FGD wastewater plants. In calculating the compliance cost estimates for each regulatory option, the EPA considered the subcategorizations established by each option and whether the plant may elect to participate in the voluntary incentive program (VIP) based on

annualized compliance costs of the technology options, as described in further detail in the preamble.

To estimate total industry compliance costs for each regulatory option with subcategories, the EPA first estimated plant-level FGD and bottom ash technology option compliance costs. The EPA then estimated unit-level costs (including capital, O&M, 3-, 5-, 6-, and 10-year recurring costs) using Equation 5-50.

$$\text{Unit-Level Cost} = \text{Plant-Level Cost} \times (\text{Unit-Level Capacity} / \text{Plant-Level Capacity})$$

Equation 5-50

Where:

Plant-Level Cost	=	Technology option plant-level cost in 2018\$. Includes capital, O&M, one-time, and recurring costs.
Unit-Level Capacity	=	Unit-level generating nameplate capacity in MW (from the Steam Electric Survey and 2016 Form EIA-860 data for new generating units).
Plant-Level Capacity	=	Plant-level generating nameplate capacity in MW (from Form EIA-860 data for 2016).

The EPA then summed the unit-level costs for only those units included in each regulatory option to estimate total industry-level regulatory option costs. See the “Generating Unit-Level Regulatory Option Costs and Loads Memorandum” for the FGD wastewater and bottom ash transport water technologies selected as basis for each plant’s regulatory option compliance cost estimates (ERG, 2019j).

Table 5-9 and Table 5-10 present the total industry compliance cost estimates for FGD wastewater and bottom ash transport water, respectively, by regulatory option. Table 5-11 presents the aggregated, industry-level compliance costs by regulatory option. All cost estimates are expressed in terms of pre-tax 2018 dollars.

**Table 5-9. Estimated Cost of Implementation for FGD Wastewater by Regulatory Option**  
[In millions of pre-tax 2018 dollars]

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Costs	Recurring Costs			
					3-year	5-year	6-year	10-year <sup>a</sup>
Baseline	70	\$1,770	\$79.2	NA	NA	NA	\$4.41	(\$14.2)
1	70	\$675	\$42.4	NA	NA	NA	\$4.41	(\$14.2)
2	70	\$934	\$74.1	NA	NA	NA	\$2.81	(\$14.2)
3	70	\$948	\$81.1	NA	NA	NA	\$2.31	(\$14.2)
4	70	\$1,500	\$172	NA	NA	NA	\$0.100	(\$14.2)

Note: Costs and cost savings are rounded to three significant figures.

NA: Not applicable.

a – The values in this column are negative, and presented in parentheses, because they represent cost savings.

**Table 5-10. Estimated Cost of Implementation for Bottom Ash Transport Water by Regulatory Option [In millions of pre-tax 2018 dollars]**

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Costs	Recurring Costs			
					3-year	5-year	6-year	10-year <sup>a</sup>
Baseline	94	\$1,680	\$96.1	\$0.132	\$1.03	\$18.3	NA	(\$23.0)
1	94	\$1,330	\$80.4	\$0.132	\$1.03	\$18.3	NA	(\$23.0)
2	94	\$1,070	\$53.5	\$0.977	\$0.00	\$12.6	NA	(\$16.5)
3	94	\$1,330	\$80.4	\$0.132	\$1.03	\$18.3	NA	(\$23.0)
4	94	\$1,330	\$80.4	\$0.132	\$1.03	\$18.3	NA	(\$23.0)

Note: Costs and cost savings are rounded to three significant figures.

NA: Not applicable.

a – The values in this column are negative, and presented in parentheses, because they represent cost savings.

**Table 5-11. Estimated Cost of Implementation by Regulatory Option [In millions of pre-tax 2018 dollars]**

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Costs	Recurring Costs			
					3-year	5-year	6-year	10-year <sup>a</sup>
Baseline	116	\$3,450	\$175	\$0.132	\$1.03	\$18.3	\$4.41	(\$37.2)
1	116	\$2,009	\$123	\$0.132	\$1.03	\$18.3	\$4.41	(\$37.2)
2	116	\$2,002	\$128	\$0.977	\$0.00	\$12.6	\$2.81	(\$30.7)
3	116	\$2,282	\$162	\$0.132	\$1.03	\$18.3	\$2.31	(\$37.2)
4	116	\$2,834	\$252	\$0.132	\$1.03	\$18.3	\$0.100	(\$37.2)

Note: Costs and cost savings are rounded to three significant figures.

a – The values in this column are negative, and presented in parentheses, because they represent cost savings.

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## SECTION 6

# POLLUTANT LOADINGS AND REMOVALS

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This section discusses types and amounts of pollutants discharged by the steam electric power generating industry, and the pollutant removals that would be achieved by the regulatory options considered for flue gas desulfurization (FGD) wastewater and bottom ash transport water discharges from steam electric power plants. The BAT/PSES regulatory options described in the preamble comprise various combinations of treatment technologies for controlling pollutants in each of these wastestreams. The regulations established by the 2015 rule remain codified in 40 CFR Part 423; the pollutant removals associated with the regulatory options for this proposed rulemaking are the incremental change in loadings (pollutant increases or reductions) relative to the loadings for plants to comply with the requirements of the 2015 rule. As such, the EPA is presenting pollutant loadings for baseline and post-compliance, defined as follows:

- *Baseline Loadings.* Pollutant loadings, in pounds per year, in FGD wastewater and/or bottom ash transport water discharged to surface water or through publicly owned treatment works (POTWs) to surface water under 2015 rule conditions. For the proposed rule, the EPA estimates baseline pollutant loadings based on plants installing the technologies selected as the BAT/PSES basis of the 2015 rule (i.e., baseline assumes full compliance with the 2015 rule, accounting for the Coal Combustion Residual (CCR) rule impacts).<sup>35</sup>
- *Post-Compliance Loadings.* Pollutant loadings, in pounds per year, in FGD wastewater and/or bottom ash transport water discharged to surface water or through POTWs to surface water after full implementation of the proposed rule technology options. The EPA estimates post-compliance pollutant loadings with the expectation that all steam electric power plants subject to the requirements of the proposed rule will install and operate wastewater treatment and pollution prevention technologies equivalent to the technology bases for the regulatory options.
- *Pollutant Removals.* The difference between the baseline loadings and post-compliance loadings for each regulatory option.

Section 6.1 describes the methodology the EPA used to estimate pollutant loadings and removals for each of the technology options evaluated for the proposed rule. Sections 6.2 and 6.3 discuss wastewater discharge flow rates and pollutant characteristics for effluent from FGD wastewater treatment systems and for bottom ash transport water, respectively. Section 6.4 presents a summary of the industry-level pollutant loadings and removals estimates for the regulatory options evaluated by the EPA.

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<sup>35</sup> Sections 5.2.1 and 5.3.1 describe the EPA's methodology to account for CCR rule impacts in the costs and pollutant loadings analyses for FGD wastewater and bottom ash transport water.

## 6.1 GENERAL METHODOLOGY FOR ESTIMATING POLLUTANT REMOVALS

For each plant discharging FGD wastewater and/or bottom ash transport water, the EPA estimated plant-level pollutant loadings for baseline and each technology option discussed in the preamble. For example, for any plant discharging FGD wastewater, the EPA calculated baseline loadings (based on chemical precipitation followed by high residence time reduction (CP+HRTR)) and post-compliance loadings associated with each technology evaluated for this proposed rule (i.e., chemical precipitation, chemical precipitation followed by low residence time reduction (CP+LRTR), and membrane filtration). For each of the pollutants identified in Table 6-1 for FGD wastewater and Table 6-2 for bottom ash transport water, the EPA estimated pollutant loadings by multiplying the discharge pollutant concentration by a plant-specific discharge flow rate to estimate the mass of pollutant discharged per year (in pounds/year).

The EPA used data collected for the 2015 rule, as well as the data described in Section 2, to characterize pollutant concentrations for FGD wastewater and bottom ash transport water. The EPA evaluated these data sources to identify analytical data that meet the EPA’s acceptance criteria for inclusion in analyses for characterizing discharges of FGD wastewater and bottom ash transport water. The EPA’s acceptance criteria for both FGD wastewater and bottom ash transport water characterization data are listed below:

- Sample locations must be unambiguous and clearly described such that the sample can be categorized as FGD wastewater or bottom ash transport water and level of treatment (e.g., untreated, partially treated).
- Analytical data must provide sufficient information to identify units of measure and determine usability in the EPA’s analyses.
- Analytical data must represent individual sample results rather than average results representing multiple plants or plant-specific long-term averages.<sup>36</sup>
- Analytical data must not be duplicative of other accepted data.
- Sample analyses must be completed using accepted analytical methods.<sup>37</sup>
- Nondetect results were not accepted if no detection or quantitation limit was provided.
- Sample results must represent total results for a pollutant (i.e., dissolved results were not accepted except for total dissolved solids (TDS)).
- For biphasic samples, sample analysis must provide results for both phases.

In addition to those noted above, the EPA reviewed all FGD wastewater data sets to confirm that the samples were representative of a BAT treatment system collected during typical plant operations. See “Development Memo for FGD Wastewater Data in the Analytical Database” for

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<sup>36</sup> Where individual sample results and plant-level average sample concentrations were both available for a dataset, the EPA preferentially used the individual sample results.

<sup>37</sup> See the memorandum titled “Development of the Bottom Ash Transport Water Analytical Dataset and Calculation of Pollutant Loadings for the Steam Electric Effluent Guidelines Proposed Rule” (ERG, 2019a) for a list of the EPA’s accepted analytical methods.

more specific details on the acceptance criteria used to generate EPA’s FGD analytical data set (ERG, 2015a).

Data for bottom ash transport water are typically collected from surface impoundments that receive multiple wastestreams and these different wastestreams have the potential to dilute or otherwise alter the characteristics of the impoundment effluent. Because of this, the EPA’s additional acceptance criteria specific to bottom ash transport water samples include:

- Sample must be at least 75 percent by volume bottom ash transport water and not include any contribution of fly ash transport water.
- Sample must be representative of actual bottom ash surface impoundment effluent collected during full-scale, typical plant operations.<sup>38</sup>

To ensure analytical data are representative of FGD wastewater or bottom ash transport water, the EPA excluded data that did not meet the acceptance criteria and, therefore, were not useable in pollutant loadings. Sections 6.2.1 and 6.3.1 present the average discharge pollutant concentrations for baseline and each technology option evaluated for FGD wastewater and bottom ash transport water, respectively.

For each plant discharging FGD wastewater or bottom ash transport water, the EPA used data from the Steam Electric Survey (ERG, 2015b) and/or industry-submitted data to determine the discharge flow rates for FGD wastewater and bottom ash transport water, and the corresponding contribution from each individual steam electric generating unit. The EPA adjusted the discharge flow rates used in the pollutant loadings estimates to account for retirements, fuel conversions, and other changes in operations scheduled to occur by December 31, 2028, described in Section 3, that will eliminate or alter the discharge of an applicable wastestream.<sup>39</sup> Finally, the Agency adjusted the discharge flow rates to account for changes in plant operations impacted by the CCR rule. For FGD wastewater, loadings were estimated using the optimized FGD flow rate described in Section 5.2.1; that section also describes how the EPA accounted for the CCR rule. Section 5.3.1 describes the development of bottom ash transport water discharge flow rates and how the EPA accounted for the CCR rule.

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<sup>38</sup> The EPA did not accept simulated surface impoundment effluent (i.e., settled ash sludge) samples or samples collected from ash-settling tests conducted in a column for characterization of bottom ash transport water. Data provided by industry has shown that these simulated samples are not good surrogates for characterizing the pollutant concentrations in effluent from surface impoundments. The surface impoundment may also receive other types of wastewater (e.g., low volume wastewaters, cooling water).

<sup>39</sup> The EPA determined that baseline and post-compliance pollutant loadings are equal to zero for steam electric generating units that announced plans to retire, convert to a non-coal fuel source, or change/upgrade ash handling practices by the time the steam electric generating units are required to meet the requirements of the proposed rule. See the memorandum titled “Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule” (ERG, 2019b) for a list of the plants and generating units that were identified as retiring, converting to a non-coal fuel, or changing/upgrading ash handling practices.

The EPA calculated baseline and post-compliance pollutant loadings for each plant discharging FGD wastewater or bottom ash transport water using the following equation:

$$\text{Loading}_{\text{pollutant}} (\text{lb/year}) = \text{Flow Rate} \times \text{Discharge Days} \times \text{Conc}_{\text{pollutant}} \times (2.20462 \text{ lb}/10^9 \mu\text{g}) \times (1000 \text{ L}/264.17 \text{ gallons})$$

Equation 6-1

Where:

Flow Rate	=	The reported flow rate of the wastestream being discharged, in gallons per day from the plant.
Discharge Days	=	The number of days per year the wastestream is discharged from the plant.
Conc <sub>pollutant</sub>	=	The concentration of a specific pollutant present in the wastestream, in micrograms per liter (μg/L).

The EPA calculated pollutant removals (i.e., the change in pollutant loadings) for each plant by subtracting the baseline loadings from the post-compliance loadings from the baseline loadings, as shown in the following equation:<sup>40</sup>

$$\text{Removal}_{\text{pollutant}} (\text{lb/year}) = \text{Loading}_{\text{post-compliance}} - \text{Loading}_{\text{baseline}}$$

Equation 6-2

Where:

Loading <sub>baseline</sub>	=	The estimated pollutant loadings discharged for a specific pollutant for the baseline technology option, in pounds per year.
Loading <sub>post-compliance</sub>	=	The estimated pollutant loadings discharged for a specific pollutant for the post-compliance technology option, in pounds per year.

The EPA identified several plants that reported transferring wastewater to a POTW rather than discharging directly to surface water. For these plants, the EPA adjusted the baseline and post-compliance loadings to account for pollutant removals expected during treatment at the POTW for each pollutant. The 2015 TDD presents the percent removals expected from well-operated POTWs. The EPA used the following equation to adjust baseline and post-compliance loadings estimates for each pollutant to account for removals achieved by the POTW:

<sup>40</sup> Where post-compliance discharge loadings are greater than baseline loadings, the pollutant removals are presented as a negative value (indicating a decrease in pollutant removals relative to baseline).



$$\text{Loading}_{\text{pollutant\_indirect}} \text{ (lb/year)} = \text{Loading}_{\text{pollutant}} \times (1 - \text{Removal}_{\text{POTW}})$$

Equation 6-3

Where:

- $\text{Loading}_{\text{pollutant}}$  = The estimated pollutant loadings from a specific pollutant if it was being discharged directly to surface water, in pounds per year.
- $\text{Removal}_{\text{POTW}}$  = The estimated percentage of the pollutant loading that will be removed by a POTW (see Table 10-1 of the 2015 TDD).

## 6.2 FGD WASTEWATER

The EPA has identified 70 coal-fired power plants that operate wet FGD systems and discharge the FGD wastewater to surface water or to a POTW, and that are not expected to retire or convert to a non-coal fuel source by December 31, 2028. For these plants, the EPA estimated pollutant loadings for baseline conditions (based on implementation of CP+HRTR or, for those plants where it is already in operation, more advanced treatment such as evaporation) and for the three technologies evaluated as the potential basis for FGD wastewater discharge requirements: chemical precipitation, CP+LRTR, and membrane filtration for the pollutants determined to be present in FGD wastewater (see Table 6-1). These technologies form the basis for the regulatory options presented in the preamble.

Section 6.2.1 identifies the pollutants present in FGD wastewater and the estimated concentrations at which they are found in the effluent from the treatment technologies evaluated for the regulatory options. Section 6.2.2 discusses the flow rates used in combination with the pollutant concentration data to estimate pollutant removals for the plants that discharge FGD wastewater. Section 6.2.3 describes the calculations used to estimate pollutant loadings for baseline and each technology option.

### 6.2.1 Pollutants Present in FGD Wastewater

For the proposed rule, the EPA used the analytical data set that was used to characterize pollutant concentrations in FGD wastewater for the 2015 rule. The EPA supplemented the 2015 data set with additional pollutant concentration data regarding the presence of bromide in FGD wastewater and treatment system performance data associated with CP+LRTR and membrane filtration technologies.

Table 6-1 presents the calculated average effluent concentrations for the following FGD wastewater treatment technologies: surface impoundments, chemical precipitation, CP+HRTR, CP+LRTR, membrane filtration, and evaporation for those pollutants that have been found with sufficient frequency and concentration to be recognized as typically present in FGD wastewater from steam electric power plants. The EPA used data from the 2015 rule to characterize pollutant concentrations in the effluent from surface impoundments, chemical precipitation, CP+HRTR, and thermal evaporation treatment systems (see Section 10.2.1 of the 2015 TDD for more information on the average effluent pollutant concentrations estimated for these technologies).

The information collected by the EPA since the 2015 rule shows that although the shorter hydraulic residence time provided by CP+LRTR can result in slightly higher variability in effluent concentrations than achieved by CP+HRTR, the overall average effluent quality of the two treatment technologies is comparable. Because of this, the pollutant concentrations used to characterize CP+HRTR effluent are reasonable estimates for the effluent pollutant concentrations following CP+LRTR. Similarly, the EPA found that the effluent quality from membrane filtration is comparable to the effluent quality attained by the thermal evaporation treatment technology. Therefore, the EPA determined that the pollutant concentrations used to characterize the effluent from thermal evaporation are reasonable estimates for the effluent pollutant concentrations following membrane treatment.

In estimating pollutant removals, the EPA also used information for bromide collected since the 2015 rule to supplement the data sets described above. For baseline and post-compliance technology options, the EPA estimated plant-specific bromide loadings for each plant using a mass balance approach. The mass balance approach estimates the plant-specific bromide loadings that result from both the naturally-occurring bromine in the coal being burned and any bromide additives that are being used for mercury emission control at the plant. The EPA used the mass balance approach for bromide because the use of refined coals and bromide additives can substantially increase the mass of bromides discharged, and the data in the record enabled the EPA to evaluate whether specific plants were relying on native coals or using approaches that increase the halogens (bromides) in the combustion and post-combustion air pollution control system. As a result, the mass balance approach provides a better estimate of the mass of bromides discharged by power plants. Additional information on the Agency’s methodology for estimating bromide loadings associated with FGD wastewater discharges is discussed in the memorandum titled “Mass Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants” (ERG, 2019c).

**Table 6-1. Pollutants Present in Treated FGD Wastewater Effluent**

Pollutant	Average Concentration (µg/L)			
	FGD Surface Impoundments	Chemical Precipitation	CP+HRTR and CP+LRTR	Evaporation and Membrane Filtration
<b>Conventional Pollutants</b>				
Total Suspended Solids (TSS)	27,900	8,590	8,590	2,000
<b>Priority Pollutants</b>				
Antimony	12.9	4.25	4.25	1.00
Arsenic	7.59	5.83	5.83	2.00
Beryllium	1.92	1.34	1.34	1.00
Cadmium	113	4.21	4.21	2.00
Chromium	17.8	6.45	6.45	4.00
Copper	21.8	3.78	3.78	2.00
Cyanide, Total	949	949	949	949
Lead	4.66	3.39	3.39	1.00
Mercury	7.78	0.139	0.0507	0.0103
Nickel	878	9.11	6.30	2.00
Selenium	1,170	928	5.72	2.00
Thallium	13.7	9.81	9.81	1.00
Zinc	1,390	20.0	20.0	28.5
<b>Nonconventional Pollutants</b>				
Aluminum	2080	120	120	100
Ammonia as N	6,850	6,850	6,850	24,300
Barium	303	140	140	10.0
Boron	243,000	225,000	225,000	3,750
Bromide <sup>a</sup>	-	-	-	-
Calcium	2,050,000	1,920,000	1,920,000	200
Chloride	7,120,000	7,120,000	7,120,000	1,500

**Table 6-1. Pollutants Present in Treated FGD Wastewater Effluent**

Pollutant	Average Concentration (µg/L)			
	FGD Surface Impoundments	Chemical Precipitation	CP+HRTR and CP+LRTR	Evaporation and Membrane Filtration
Cobalt	183	9.30	9.30	10.0
Iron	1,510	110	110	100
Magnesium	3,370,000	3,370,000	3,370,000	200
Manganese	93,400	12,500	12,500	10.0
Molybdenum	125	125	125	20.0
Nitrate Nitrite as N	96,000	96,000	647	100
Phosphorus, Total	319	319	319	25.0
Sodium	276,000	276,000	276,000	5,000
Titanium	27.1	9.30	9.30	10.0
Total Dissolved Solids (TDS)	32,500,000	24,100,000	24,100,000	10,800
Vanadium	16.4	12.6	12.6	5.00

Source: (U.S. EPA, 2015).

Note: Concentrations are rounded to three significant figures.

a – The EPA estimated bromide loadings for each plant discharging FGD wastewater using a mass balance approach, as discussed in the memorandum titled “Mass Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants” (ERG, 2019c). The average total concentration is presented as a calculated value based on two values, one representing the average total concentration of plants not burning refined coal and not applying brominated compounds (59,100 µg/L) and one representing the average total concentration of plants burning refined coal or applying brominated compounds (167,000 µg/L).

### 6.2.2 FGD Wastewater Flows

The EPA used industry-submitted data, Steam Electric Survey data, and other data sources discussed in Section 2 to characterize FGD wastewater discharge flows. As described in Section 5.2.1, the EPA calculated plant-specific FGD purge flow rates and optimized FGD flow rates to estimate compliance costs for each of the 70 coal-fired power plants discharging FGD wastewater. To be consistent with the EPA’s methodology for estimated plant-level O&M compliance costs, the EPA used plant-specific optimized FGD flow rates to estimate baseline and post-compliance loadings.

### 6.2.3 Baseline and Technology Option Loadings

The EPA estimated plant-specific loadings for baseline discharges and each treatment technology option considered for control of FGD wastewater, as shown in the FGD Loads Database (ERG, 2019d). As discussed in Section 6.1, the EPA multiplied the average effluent pollutant concentrations for the applicable FGD wastewater treatment technology with the plant-specific FGD discharge flow rate to calculate the pollutant loadings discharged to surface water for each plant.<sup>41</sup> The EPA used the same plant-specific flow rate for baseline and each technology option evaluated, only changing the pollutant concentration based on the technology option.

In estimating pollutant loadings, the EPA assumed the following:

#### Baseline Loadings (CP+HRTR):

- The EPA used CP+HRTR concentrations from Table 6-1 for plants not currently operating, or planning to operate, CP+HRTR or other treatment (such as evaporation) targeting selenium, nitrate/nitrite, arsenic, and mercury removal. The EPA assumes that these plants would install a CP+HRTR system to comply with effluent requirements established under the 2015 rule.
- The EPA used the corresponding concentrations from Table 6-1 for CP+HRTR for plants already operating CP+HRTR systems, or otherwise in compliance with the 2015 rule. EPA assumes that these plants will continue to operate their existing FGD wastewater treatment technologies.

Based on discussions with industry representatives and engineering firms, plants that currently operate evaporation systems are estimated to have zero baseline pollutant loadings. Because the effluent quality from evaporation treatment is far superior to the water sources (e.g., river water) typically used by plants for scrubber makeup water purposes<sup>42</sup>, and because reusing the evaporation effluent within the FGD system obviates the need to monitor treatment system effluent quality for compliance with NPDES permit limitations (and thereby saves money and

<sup>41</sup> The EPA adjusted loadings for plants discharging to a POTW to account for additional removals that will take place at the POTW.

<sup>42</sup> For example, mist eliminator wash water or limestone slurry preparation.

avoids potential for noncompliance), the EPA determined that it is reasonable to assume plants will choose to reuse the treated effluent within the FGD scrubber system.

Chemical Precipitation:

- The EPA used chemical precipitation concentrations from Table 6-1 for plants currently treating FGD wastewater with a surface impoundment, or other treatment technologies that do not meet the requirements for this option. EPA assumes that these plants will install a chemical precipitation treatment system to meet the effluent requirements.
- The EPA used chemical precipitation concentrations from Table 6-1 for plants already operating all or any part of a chemical precipitation system.

The discharge loadings for all plants operating FGD wastewater treatment more advanced than surface impoundments or chemical precipitation (e.g., CP+LRTR or CP+HRTR) remain unchanged from baseline.

CP+LRTR:

- The EPA used CP+LRTR concentrations from Table 6-1 for plants with existing surface impoundments or chemical precipitation systems without additional treatment for selenium and nitrate/nitrite.

Plants currently treating their FGD wastewater with a CP+LRTR, CP+HRTR or evaporation system will continue doing so; thus, their loadings remain unchanged from baseline.

Membrane Filtration:

- The EPA assumes plants with a surface impoundment, chemical precipitation system, or biological treatment system (i.e., HRTR or LRTR systems) will install and operate a membrane filtration system with brine encapsulation to meet the effluent requirements.
- EPA assumes that plants already operating evaporation systems, or otherwise in compliance with this technology option, will continue to operate their current FGD wastewater treatment technologies.

Plants installing membrane filtration are estimated to have zero post-compliance loadings because these plants are likely to reuse treatment system effluent (i.e., membrane permeate) within the FGD scrubber system, rather than discharge and monitor this effluent stream.<sup>43</sup> Plants

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<sup>43</sup> The effluent quality from membrane filtration (i.e., membrane permeate) is far superior to the water sources typically used by plants for scrubber makeup water purposes. Reusing the membrane permeate stream within the FGD system obviates the need to monitor treatment system effluent quality for compliance with NPDES permit limitations (saving money and avoiding potential for noncompliance); therefore, the EPA determined that it is reasonable to assume plants will choose to reuse the treated effluent within the FGD scrubber system.

currently treating their FGD wastewater with an evaporation system will continue doing so; thus, their loadings remain unchanged from baseline.

The EPA identified two plants transferring FGD wastewater to a POTW. The EPA expects that these plants will continue to transfer the wastewater to a POTW for all technology options other than membrane filtration. Therefore, the EPA adjusted the baseline and post-compliance loadings to account for pollutant removals associated with POTW treatment, as described in Section 6.1.

### **6.3 BOTTOM ASH TRANSPORT WATER**

This section discusses the EPA’s method for estimating annual pollutant loadings and removals for steam electric power plants that discharge bottom ash transport water and are not expected to retire or convert fuel sources by December 31, 2028. The EPA identified 71 coal-fired power plants that operate wet bottom ash handling systems and discharge the bottom ash transport water to surface water or to a POTW, and that are not expected to retire or convert to a non-coal fuel source by December 31, 2028. For these plants, the EPA estimated pollutant loadings for baseline conditions (based on dry handling or operating a closed-loop recycle bottom ash system that complies with a zero discharge standard) and for the two technology options evaluated as the basis for bottom ash transport water discharge requirements: (1) dry handling or high rate recycle bottom ash system with a purge (high recycle rate); and (2) dry handling or high rate recycle bottom ash system with a purge or, for certain plants, a best management practices (BMP) plan (high recycle rate/BMP plan). These technologies form the basis for the regulatory options presented in the preamble.

Section 6.3.1 identifies the pollutants present and estimated concentrations in bottom ash transport water. Section 6.3.2 discusses the flow rates used in combination with the pollutant concentration data to estimate pollutant loadings for the plants that discharge bottom ash transport water. Section 6.3.3 describes the calculations used to estimate pollutant loadings for baseline and each technology option.

#### **6.3.1 Pollutants Present in Bottom Ash Transport Water**

For the proposed rule, the EPA updated the analytical data set used to characterize pollutant concentrations in bottom ash transport water for the 2015 rule. The EPA supplemented the data for the 2015 rule with new industry-submitted analytical data collected by plants as part of the EPA’s voluntary bottom ash transport water sampling program and data submitted by industry during the final stage of the 2015 rulemaking.<sup>44</sup> The EPA evaluated these data sources to identify analytical data that meet the EPA’s acceptance criteria for inclusion in analyses for characterizing discharges of bottom ash transport water.

The EPA also removed certain data and corrected a small number of data in the 2015 rule analytical data set. One source of data used to characterize bottom ash surface impoundment effluent during the previous rulemaking was a set of sampling data collected for a rulemaking

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<sup>44</sup> In December 2017, the EPA requested seven plants operating surface impoundments primarily containing bottom ash transport water to participate in a voluntary sampling program. Two plants agreed to participate in the sampling program and submitted bottom ash surface impoundment data to the EPA (CPS Energy, 2018; TEC, 2018).

promulgated in 1982; the EPA has excluded these data from the data set used to estimate pollutant removals for the proposed revisions to the 2015 rule. The EPA also identified sample-specific errors present in the 2015 rule analytical data and made corrections as warranted.

Additional information on evaluated data sources, EPA’s acceptance criteria, and development of the analytical data set for characterization of bottom ash transport water is provided in the memorandum titled “Development of the Bottom Ash Transport Water Analytical Data set and Calculation of Pollutant Loadings for the Steam Electric Effluent Guidelines Proposed Rule” (ERG, 2019a).

The EPA used the updated bottom ash transport water analytical data set to calculate an industry average concentration for each pollutant present in the bottom ash transport water using the same methodology as the 2015 rule, described in Section 10 of the 2015 TDD.<sup>45</sup> Table 6-2 presents the average effluent concentrations for pollutants present in bottom ash transport water.

**Table 6-2. Pollutants Present in Bottom Ash Transport Water Effluent**

Pollutant	Unit	Average Concentration
<b>Conventional Pollutants</b>		
Chemical Oxygen Demand (COD)	µg/L	20,800
Total Suspended Solids (TSS)	µg/L	13,400
<b>Priority Pollutants</b>		
Antimony	µg/L	17.3
Arsenic	µg/L	9.32
Cadmium	µg/L	0.721
Chromium	µg/L	5.08
Copper	µg/L	3.95
Lead	µg/L	10.4
Mercury	µg/L	0.102
Nickel	µg/L	17.5
Selenium	µg/L	12.3
Thallium	µg/L	1.13
Zinc	µg/L	33.8
<b>Nonconventional Pollutants<sup>a</sup></b>		
Aluminum	µg/L	854
Barium	µg/L	106
Boron	µg/L	5,310

<sup>45</sup> The data associated with bottom ash surface impoundments typically include other wastestreams (e.g., low volume wastewaters, cooling water); as a result, the effluent concentrations due to bottom ash transport water are likely suppressed somewhat due to dilution. Because of this, the baseline pollutant loadings and post-compliance pollutant removals are underestimated to some degree. Nevertheless, the EPA determined that the pollutant removal estimates calculated for this rule represent a reasonable estimate of the degree of pollutant removal that would be achieved by the BAT/PSES limitations.



**Table 6-2. Pollutants Present in Bottom Ash Transport Water Effluent**

Pollutant	Unit	Average Concentration
Bromide	µg/L	5,100
Calcium	µg/L	154,00
Chloride	µg/L	321,000
Cobalt	µg/L	9.19
Iron	µg/L	676
Magnesium	µg/L	55,700
Manganese	µg/L	153
Molybdenum	µg/L	28.3
Nitrate-Nitrite (as N)	µg/L	1,670
Phosphorus	µg/L	222
Potassium	µg/L	19,600
Silica	µg/L	8,160
Sodium	µg/L	119,000
Strontium	µg/L	1,430
Sulfate	µg/L	504,000
Sulfite	µg/L	3,920
Titanium	µg/L	35.9
Total Dissolved Solids (TDS)	µg/L	1,290,000
Total Kjeldahl Nitrogen (TKN)	µg/L	968
Vanadium	µg/L	10.1

Source: U.S. EPA, 2015; ERG, 2019e.

Note: Loadings are rounded to three significant figures. The EPA did not generate an average pollutant concentration for pollutants where all sample results are less than the quantitation limit.

a – The EPA identified ammonia (as N) as a pollutant present in bottom ash transport water; however, the EPA excluded this parameter from the calculation of pollutant loadings to avoid double-counting of nitrogen compounds.

### **6.3.2 Bottom Ash Transport Water Flows**

The EPA used industry-submitted data and data from the Steam Electric Survey, discussed in Section 2, to calculate bottom ash transport water flow rates for baseline conditions and each technology option evaluated for this proposed rule.

For baseline conditions, the EPA estimated bottom ash transport water flow rates as zero for generating units subject to the BAT/PSES effluent limitations requiring zero discharge of bottom ash transport water. For generating units for which the zero discharge standard does not apply (i.e., generating units with nameplate capacity equal to 50 megawatts (MW) or less), the EPA used information from the Steam Electric Survey to calculate a normalized bottom ash transport water discharge flow rate using the same approach outlined in Section 10.3.2 of the 2015 TDD.

For the high recycle rate technology option, which would allow for plants to discharge a portion of their bottom ash transport water, the EPA estimated the post-compliance bottom ash transport water flow rates for two compliance approaches available to most plants:

- Zero Flow – For the compliance approach that uses a dry bottom ash handling system (e.g., under-boiler mechanical drag system (MDS)), the discharge flow rate would equal zero.
- Purge Flow – For the compliance approach that uses a recirculating bottom ash handling system (i.e., remote mechanical drag system (rMDS) operated with a purge instead of completely closed-loop), the EPA estimated a purge volume for each plant. The EPA calculated bottom ash transport water purge flow rates for rMDS installations based on a relationship between the plant generating capacity and the volume of the total wetted, active components of the rMDS, consistent with the methodology described in Section 5.3.3.

The bottom ash transport water flow rate used to estimate post-compliance pollutant removals is based on the lowest cost control technology selected for each plant.<sup>46</sup>

For the high recycle rate/BMP plan technology option, the EPA estimated bottom ash transport water flow rates as described above and also estimated a bottom ash transport water flow associated with the BMP plan alternative. For plants subject to the implementation of a BMP plan, the EPA assumed that the plant will continue to discharge bottom ash transport water consistent with current operations. The EPA used information from the Steam Electric Survey to calculate a normalized bottom ash transport water discharge flow rate consistent with the methodology described in Section 10.3.2 of the 2015 TDD.

### **6.3.3 Baseline and Technology Option Loadings**

The EPA estimated generating unit-specific loadings for baseline discharges and each post-compliance technology option considered for control of bottom ash transport water, see the Bottom Ash Transport Water Pollutant Loadings Model (ERG, 2019e). To calculate the mass of pollutants discharged from each plant, the EPA multiplied the average concentration of each pollutant in Table 6-2 with the generating unit-specific discharge flow rate associated with the bottom ash handling technology basis, described in Section 6.3.2, for the baseline and post compliance technology options. Using the generating unit-level loadings, the EPA then calculated the baseline and post-compliance loadings for each plant as the sum of pollutant loadings for all generating units and at the industry level for each evaluated technology option.

Based on Steam Electric Survey data, six plants in the current population operate their wet-sludging bottom ash handling systems with a surface impoundment managed as a closed-loop recycle process. The record indicates that these plants have designated outfalls for bottom ash

<sup>46</sup> As described in Section 8.3, the EPA estimated costs associated with converting to both an MDS and remote MDS with a purge, and then selected the most affordable of the technologically available system for each plant. However, for instances where the MDS is the lowest cost approach for a generating unit but the EPA has information showing that the unit is unable to convert to that system (e.g., insufficient space under the boiler). EPA's methodology assumes the generating unit will install the remote MDS.

transport water; however, did not use these outfalls for emergency discharges from the closed-loop recycle process. As described in Section 5.3.5, the EPA estimates a one-time cost associated with consulting and engineering to completely close the bottom ash recycle system. These actions would eliminate the potential for future discharges of bottom ash transport water. As a result, the EPA’s analysis assumes that there are no baseline pollutant loadings or post compliance pollutant removals for these plants.

The EPA identified two plants transferring bottom ash transport water to a POTW. For these plants, the EPA adjusted the baseline and post-compliance loadings to account for pollutant removals associated with POTW treatment, as described in Section 6.1.

#### **6.4 SUMMARY OF BASELINE AND REGULATORY OPTION LOADINGS AND REMOVALS**

As described in the preamble, the EPA evaluated four regulatory options comprising various combinations of technology options to control FGD wastewater and bottom ash transport water. The EPA estimated the pollutant loadings for baseline and each regulatory option, as well as removals associated with steam electric power plants to achieve compliance for each of the main regulatory options. This section discusses the specific loadings and removals calculations for each regulatory option evaluated by the EPA. This section also presents the aggregated industry-level loadings and removals for each wastestream and regulatory option.

The EPA applied different effluent limitations to steam electric generating units with a specific steam electric power generating capacity, generating units with a specific net power generation, and “high-flow” FGD wastewater plants. In calculating the pollutant loadings estimates for each regulatory option, the EPA considered the subcategorizations established by each option and whether the plant may elect to participate in the voluntary incentive program (VIP) based on annualized compliance costs of the technology options.<sup>47</sup> For example, for all regulatory options the EPA applied different effluent limitations for generating units with a capacity of 50 MW or less. In this case, the plant will not face more stringent requirements than preexisting regulations; therefore, baseline and post-compliance loadings are estimated based on the treatment technology currently in place and removals are not estimated for all regulatory options. The preamble describes the subcategorizations and requirements applicable for each of the four regulatory options evaluated by the EPA.

In order to estimate the total industry pollutant loadings and removals for each regulatory option (accounting for subcategories), the EPA first estimated plant-level FGD wastewater and bottom ash transport water pollutant loadings based on the technology bases selected for each plant. The EPA then estimated pollutant loadings for each generating unit by applying a generating unit flow fraction to the flow rates calculated for each plant. See the “FGD Purge Flow Methodology” memorandum for the FGD wastewater and the Bottom Ash Transport Water Pollutant Loadings Model for bottom ash transport water flow rates used to estimate each plant’s regulatory option loadings (ERG, 2019e and 2019f).

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<sup>47</sup> For Regulatory Option 2 and Regulatory Option 3, the EPA considered whether each plant’s annualized cost for the VIP technology basis (membrane filtration) is less than the annualized cost for chemical precipitation followed by LRTR. Where the annualized cost for membrane filtration is less than the other regulatory options, the EPA assumed the plant will install membrane treatment and estimated zero post-compliance loadings.

Table 6-3 and Table 6-4 present the total industry pollutant loadings and removals for FGD wastewater and bottom ash transport water, respectively, in pounds per year for baseline and each regulatory option. Table 6-5 presents the aggregated, industry-level pollutant loadings and removals at baseline and each of the four regulatory options. Pollutant loadings and removals are presented in pounds per year and account for the CCR rule. Pollutant loadings and removals presented in these tables are calculated as the sum of TDS and TSS. The EPA estimated the pollutant removals by subtracting the baseline loadings from the post-compliance loadings. The memorandum titled “Generating Unit-Level Costs and Loadings Estimates by Regulatory Option” presents the baseline and post-compliance pollutant loadings for each wastestream and each regulatory option at the plant-level (ERG, 2019g).

**Table 6-3. Estimated Industry-Level FGD Wastewater Pollutant Loadings and Estimated Change in Loadings by Regulatory Option**

Regulatory Option <sup>a</sup>	Estimated Total Industry Loading (lb/year)	Estimated Change in Total Industry Loadings (lb/year) <sup>a</sup>
Baseline	1,660,000,000	-
1	1,660,000,000	-
2	1,470,000,000	-195,000,000
3	1,380,000,000	-289,000,000
4	328,000,000	-1,340,000,000

Source: ERG, 2019h.

Note: Loadings and removals are rounded to three significant figures.

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

**Table 6-4. Estimated Industry-Level Bottom Ash Transport Water Pollutant Loadings and Estimated Change in Loadings by Regulatory Option**

Regulatory Option	Estimated Total Industry Loading (lb/year)	Estimated Change in Total Industry Loadings (lb/year) <sup>a</sup>
Baseline	984,000	-
1	14,300,000	13,400,000
2	91,900,000	91,000,000
3	14,300,000	13,400,000
4	14,300,000	13,400,000

Source: ERG, 2019h.

Note: Loadings and removals are rounded to three significant figures.

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

**Table 6-5. Estimated Industry-Level Pollutant Loadings and Estimated Change in Loadings by Regulatory Option**

Regulatory Option	Estimated Total Industry Loading (lb/year)	Estimated Change in Total Industry Loadings (lb/year) <sup>a</sup>
Baseline	1,670,000,000	--
1	1,680,000,000	13,400,000
2	1,560,000,000	-104,000,000
3	1,390,000,000	-276,000,000
4	342,000,000	-1,320,000,000

Source: ERG, 2019h.

Note: Loadings and removals are rounded to three significant figures.

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

## 6.5 REFERENCES

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## SECTION 7

# NON-WATER QUALITY ENVIRONMENTAL IMPACTS

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The elimination or reduction of one form of pollution has the potential to aggravate other environmental problems, an effect frequently referred to as cross-media impacts. Sections 304(b) and 306 of the Clean Water Act (CWA) require the EPA to consider non-water-quality environmental impacts (NWQEI), including energy impacts, associated with effluent limitations guidelines and standards (ELGs). Accordingly, the EPA has considered the potential impacts of the proposed regulatory options for flue gas desulfurization (FGD) wastewater and bottom ash transport water discharged from steam electric power plants on energy consumption (including fuel usage), air emissions, solid waste generation, and water use. The regulations promulgated by the 2015 rule remain codified in 40 CFR Part 423; the NWQEI associated with the regulatory options for this proposed rulemaking are the incremental changes in NWQEI (an increase or decrease) relative to the NWQEI for plants to meet the requirements of the 2015 rule.

### 7.1 ENERGY REQUIREMENTS

Steam electric power plants use energy (including fuel) when transporting ash and other solids on or off site, operating wastewater treatment systems, or operating ash handling systems. For those plants that are estimated to incur costs associated with the proposed rule, the EPA considered whether there would be an associated incremental change in energy need compared to the 2015 rule requirements (baseline). That need varies depending on the regulatory option evaluated and the current operations of the plant. Therefore, as applicable, the EPA estimated the change in energy usage in megawatt hours (MWh) for equipment added to the plant systems or in consumed fuel (gallons) for transportation or equipment operation. Specifically, the EPA estimated energy usage associated with operating equipment for the FGD wastewater treatment systems and bottom ash handling system considered for this proposed rule.

To estimate changes in plant-specific energy usages associated with operating FGD wastewater treatment equipment, the EPA developed relationships between FGD wastewater flow and energy usage for the following technologies: chemical precipitation, low residence time reduction (LRTR) biological treatment, high residence time reduction (HRTR) biological treatment, and membrane filtration. To estimate plant-specific energy usages for operating bottom ash handling systems, the EPA developed relationships between generating unit capacity and energy usage for the following technologies: mechanical drag system (MDS), remote mechanical drag system (rMDS) with a purge, and rMDS with RO treatment of a slipstream to achieve complete recycle. The EPA estimated electrical energy use from horsepower ratings of system equipment (e.g., pumps, mixers, silo unloading equipment) and energy usage data provided by wastewater treatment vendors. See EPA's memorandum "Non-Water Quality Environmental Impacts for Proposed Revisions to the Steam Electric Effluent Limitations Guidelines and Standards" for additional details (ERG, 2019).

Similarly, as applicable, the EPA also estimated the change in energy use that would result from ceasing wet-slucing of bottom ash and reduced use of earthmoving equipment in order to comply with the 2015 rule requirements and all proposed regulatory options. The EPA estimated electrical energy use from horsepower ratings of wet-slucing system pumps and the earthmoving

equipment engine. The EPA estimated energy savings associated with only earthmoving equipment for plants sending FGD solids or bottom ash to surface impoundments.

The EPA summed plant-specific energy usage estimates to calculate the net change in energy requirements for the regulatory options considered for the proposed rule, presented in Table 7-1.

Energy usage also includes the fuel consumption associated with the changes in transportation needed to landfill solid waste and combustion residuals (e.g., ash) at steam electric power plants to on-site or off-site landfills, based on plant-specific data, using open dump trucks. In general, the EPA calculated fuel usage based on the estimated amount of time spent loading and unloading solid waste and combustion residuals into dump trucks and the fuel consumption during idling plus the estimated total transportation distance, number of trips required per year to dispose of the solid waste and combustion residuals, and fuel consumption. The frequency and distance of transport depends on a plant’s operation and configuration. For example, the volume of waste generated per day determines the frequency with which trucks will be travelling to and from the storage sites. The availability of either an on-site or off-site landfill, and its estimated distance from the plant, determines the length of travel time. See EPA’s memorandum “Non-Water Quality Environmental Impacts for Proposed Revisions to the Steam Electric Effluent Limitations Guidelines and Standards” for more information on the specific calculations used to estimate fuel consumption associated with the transport and disposal of solid waste and combustion residuals (ERG, 2019). Table 7-1 shows the net change in national annual fuel consumption associated with the regulatory options considered for the proposed rule and the 2015 baseline.

**Table 7-1. Net Change in Energy Use for the Proposed Regulatory Options Compared to Baseline**

Non-Water-Quality Impact	Net Change in Energy Use Associated with ELG			
	Option 1	Option 2	Option 3	Option 4
Electrical Energy Usage (Megawatt Hours)	-82,300	-54,500	-26,600	94,300
Fuel (Gallons Per Year)	0	-47,400	40,300	243,000

Note: Negative values represent a decrease in energy use compared to baseline. Positive values represent an increase in energy use compared to baseline.

## 7.2 AIR EMISSIONS POLLUTION

The final rule is expected to affect air pollution through three main mechanisms:

- Changes in power requirements by steam electric power plants to operate wastewater treatment and bottom ash handling systems needed to comply with the proposed regulatory options.
- Changes to transportation-related emissions due to the trucking of combustion residual waste to landfills.



- Changes in the profile of electricity generation due to the proposed regulatory options.

This section provides greater detail on air emission changes associated with the first two mechanisms and presents the estimated net change in air emissions associated with all three mechanisms. See EPA’s *Benefit and Cost Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for additional discussion of the third mechanism (U.S. EPA, 2019).

Air pollution is generated when fossil fuels burn. Steam electric power plants also generate air emissions from operating vehicles such as dump trucks, vacuum trucks, dust suppression water trucks, and earthmoving equipment, which all release criteria air pollutants and greenhouse gases. Criteria air pollutants are those pollutants for which a national ambient air quality standard (NAAQS) has been set and include sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>). Greenhouse gases are gases such as carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O) that absorb radiation, thereby trapping heat in the atmosphere, and contributing to a wide range of domestic effects.<sup>48</sup> Conversely, decreasing energy use or less vehicle operation will result in decreased air pollution.

The EPA calculated air emissions resulting from the change in power requirements<sup>49</sup> using year-explicit emission factors estimated by the Integrated Planning Model (IPM)<sup>50</sup> for CO<sub>2</sub>, NO<sub>x</sub>, and SO<sub>2</sub>. The IPM output provides estimates of electricity generation and resulting emissions by plant and North American Electric Reliability Corporation (NERC) region. The EPA used detailed outputs for the 2030 IPM run year to estimate plant- and NERC-level emission factors (mass of pollutant emitted per kilowatt-hour of electricity generated) over the period of analysis. This run year represents steady-state conditions after rule implementation, when all plants are estimated to meet the revised BAT limits and pretreatment standards associated with each analyzed regulatory option.

The EPA calculated NO<sub>x</sub>, CO<sub>2</sub>, and SO<sub>2</sub> emissions resulting from changes in power requirements based on the incremental auxiliary power electricity consumption, the pollutant- and year-specific emission factors, and the timing plants are assumed to install the compliance technology and start incurring additional electricity consumption.

The EPA assumed that plants with capacity utilization rates (CUR) of 90.4 percent or less would generate the additional auxiliary electricity on site and therefore estimated emissions using plant-specific and year-explicit emission factors obtained from IPM outputs.<sup>51</sup>

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<sup>48</sup> The EPA did not specifically evaluate nitrous oxide emissions as part of the NWQEI analysis. To avoid double counting air emission estimates, the EPA calculated only nitrogen oxide emissions, which would include nitrous oxide emissions.

<sup>49</sup> Power requirements refers to the electricity needed to operate FGD wastewater treatment and/or bottom ash handling technologies. Plants may generate this electricity on site or purchase the electricity from the grid.

<sup>50</sup> IPM is a comprehensive electricity market optimization model that can evaluate cost and economic impacts within the context of regional and national electricity markets. IPM is used by the EPA to analyze the estimated impact of environmental policies on the U.S. power sector.

<sup>51</sup> Emission factors are calculated as plant-level emissions divided by plant-level generation.

The EPA assumed that plants with CUR greater than 90.4 percent would draw additional electricity from the grid within the NERC region, instead of generating it on site. These plants will be using part of their existing generation to power equipment; however, other plants within the same NERC region would need to generate electricity to compensate for this reduction and meet electricity demands. Therefore, for these high CUR plants, the EPA used NERC-average emission factors instead of plant-specific emissions factors.

Because the EPA ran IPM for Regulatory Options 2 and 4 only, the EPA used IPM emission factors calculated for Regulatory Option 2 to estimate changes in power requirements air emissions for Regulatory Options 1 and 3.

To estimate air emissions associated with operation of transport vehicles, the EPA used the MOVES2014b model to generate air emission factors for NO<sub>x</sub>, SO<sub>2</sub>, CO<sub>2</sub>, and CH<sub>4</sub>. The EPA assumed the general input parameters such as the year of the vehicle and the annual mileage accumulation by vehicle class to develop these factors (U.S. EPA, 2018b). Table 7-2 lists the transportation emission factors for each air pollutant considered in the NWQEI analysis.

**Table 7-2. MOVES Emission Rates for Model Year 2010 Diesel-fueled, Short-haul Trucks Operating in 2018**

Roadway Type	NO <sub>x</sub> (ton/mi)	SO <sub>2</sub> (ton/mi)	CO <sub>2</sub> (ton/mi)	CH <sub>4</sub> (ton/mi)
Highway (restricted access)	1.34E-06	1.18E-08	0.00141	4.23E-08
Local (unrestricted access)	1.51E-06	1.23E-08	0.00147	6.80E-08

Source: U.S. EPA, 2018b. MOVES2014 (database version movesdb20180517).  
 Vehicle types: Single and Combination Unit Short-haul Trucks

The EPA calculated the air emissions associated with the operation of transport vehicles estimated for the regulatory options using the transportation pollutant-specific emission rate per mile, the estimated round trip distance to and from the on-site or off-site landfill, and the number of calculated trips for one year in the transportation methodology to truck all solid waste or combustion residuals to the on-site or off-site landfill.

The EPA estimated the annual number of miles that dump trucks moving ash or wastewater treatment solids to on- or off-site landfills would travel to comply with limitations associated with the regulatory options. See EPA’s memorandum “Non-Water Quality Environmental Impacts for Proposed Revisions to the Steam Electric Effluent Limitations Guidelines and Standards” for more information on the specific calculations used to estimate transport distance and number of trips per year (ERG, 2019). The changes in national annual air emissions associated with auxiliary electricity and transportation for each of the regulatory options are shown in Table 7-3.

**Table 7-3. Net Change in Industry-Level Air Emissions Associated with Power Requirements and Transportation by Regulatory Option**

Non-Water Quality Impact	Air Emissions Associated with the ELG			
	Option 1	Option 2 <sup>a</sup>	Option 3	Option 4 <sup>b</sup>
NO <sub>x</sub> (tons/year)	-49.3	-33.2	-16.0	32.7
SO <sub>x</sub> (tons/year)	-81.9	-54.3	-26.9	20.4
CO <sub>2</sub> (metric tons/year)	-66,500	-44,500	-21,600	60,600
CH <sub>4</sub> (tons/year)	0	-0.015	0.009	0.051

Note: Negative values represent a decrease in air emissions compared to baseline. Positive values represent an increase in air emissions compared to baseline.

<sup>a</sup> Option 2 emissions are based on the IPM sensitivity analysis scenario that includes the ACE rule in the baseline.

<sup>b</sup> Option 4 emissions are based on the IPM sensitivity analysis scenario that does not include the ACE rule in the baseline.

The EPA estimated the change in the profile of electricity generation under Regulatory Options 2 and 4 using IPM. IPM predicts changes in electricity generation across all electricity generating units, including those at plant to which the ELGs apply and which see changes in compliance costs under the proposed regulatory options. The EPA predicts that these changes, either increases or decreases, in electricity generation affect the air emissions from steam electric power plants. The net changes in total annual air emissions attributable to the selected regulatory options, compared to baseline, are shown in Table 7-4.

**Table 7-4. Net Change in Industry-Level Air Emissions for Regulatory Options 2 and 4.**

Non-Water Quality Impact	Net Change in Air Emissions Associated with the ELG	
	Option 2 <sup>a</sup>	Option 4 <sup>b</sup>
NO <sub>x</sub> (tons/year)	5,000	1,030
SO <sub>x</sub> (tons/year)	5,000	1,890
CO <sub>2</sub> (metric tons/year)	5,660,000	1,240,000
CH <sub>4</sub> (tons/year)	-0.015	0.051

Note: Negative values represent a decrease in air emissions compared to baseline. Positive values represent an increase in air emissions compared to baseline.

<sup>a</sup> Option 2 emissions are based on the IPM sensitivity analysis scenario that includes the ACE rule in the baseline.

<sup>b</sup> Option 4 emissions are based on the IPM sensitivity analysis scenario that does not include the ACE rule in the baseline.

### 7.3 SOLID WASTE GENERATION

Steam electric power plants generate solid waste associated with sludge from wastewater treatment systems (e.g., chemical precipitation, biological treatment, membrane filtration). The EPA estimated the amount of solids generated from the selected technology under each regulatory option for each plant.

Bottom ash solids are also generated at steam electric power plants. The proposed regulatory options are not expected to alter the amount of bottom ash generated by the steam electric power generating industry because the type of bottom ash transport system installed to handle the ash does not change the amount of bottom ash generated during combustion. Therefore, the estimated amount of bottom ash solids generated under the proposed regulatory options are comparable to the baseline. See EPA’s memorandum “Non-Water Quality Environmental Impacts for Proposed Revisions to the Steam Electric Effluent Limitations Guidelines and Standards” for the specific calculations of solids generated (ERG, 2019). The net change in national annual solid waste production associated with the regulatory options are shown in Table 7-5.

**Table 7-5. Net Change in Industry-Level Solid Waste from Baseline, by Regulatory Option**

Non-Water Quality Impact	Change in Industry Solid Waste Generation from Baseline			
	Option 1	Option 2	Option 3	Option 4
Solids (tons/year)	-1.66	329,000	488,000	2,330,000

Note: Negative values represent a decrease in solid waste generation compared to baseline. Positive values represent an increase in solid waste generation compared to baseline.

## 7.4 CHANGE IN WATER USE

Steam electric power plants generally use water for handling solid waste, including bottom ash, and for operating wet FGD scrubbers. The technology options for bottom ash transport water will eliminate or reduce water use associated with wet ash sluicing operating systems. Baseline required zero discharge of bottom ash transport water; therefore, the EPA estimated an increase in water use associated with all regulatory options compared to baseline, due to the purge bottom ash transport water from rMDS under the options. The EPA estimated the increase in water use based on plant-specific rMDS purge flows. Two of the three technology options for FGD wastewater discharges—chemical precipitation and chemical precipitation plus LRTR—are not expected to reduce the amount of intake water. Plants expected to install a membrane filtration system for FGD wastewater treatment under Regulatory Options 2, 3, and 4 are expected to experience a decrease in water use compared to baseline because the EPA assumes they will reuse the membrane permeate in the FGD scrubber. The EPA estimated the reduction in water use resulting from membrane filtration treatment to be 70 percent of the optimized FGD flow for each plant expected to install membrane filtration.

Table 7-6 presents the estimated incremental change in process water use for each regulatory option evaluated for the ELGs compared to baseline. The change in water use for each regulatory option is assumed to be equivalent to the change in wastewater discharge.

**Table 7-6. Net Change in Industry-Level Process Water Use by Regulatory Option**

Non-Water Quality Impact	Change in Water Use from Baseline with the Option			
	Option 1	Option 2	Option 3	Option 4
Water Reduction (MGD)	3.370	21.1	0.613	-9.38

Note: Negative values represent a decrease in water use compared to baseline. Positive values represent an increase in water use compared to baseline.

## 7.5 REFERENCES

1. ERG. 2019. “Steam Electric Effluent Guidelines Non-Water Quality Environmental Impacts Memorandum to the Steam Electric Rulemaking Record.” (August). DCN SE08483.
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3. U.S. EPA, 2019. U.S. Environmental Protection Agency. *Benefit and Cost Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA Report). (October). DCN SE07401.

## **SECTION 8**

# **EFFLUENT LIMITATIONS**

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This section describes the pollutants selected for regulation for each wastestream evaluated as part of this reconsideration and the methodology used to calculate the proposed effluent limitations and standards. This section also describes the derivation of the allowable purge volume for discharges of bottom ash transport water from power plants operating recirculating bottom ash handling systems. As used in this section, regulated pollutants are pollutants for which the EPA would establish numerical effluent limitations and standards.

### **8.1 SELECTION OF REGULATED POLLUTANTS FOR FGD WASTEWATER**

Effluent limitations and standards for all pollutants present in a wastestream often are not necessary to ensure that wastewater pollution is adequately controlled because many of the pollutants originate from similar sources, have similar treatability, and are removed by similar mechanisms. Therefore, in some instances, it may be sufficient to establish effluent limitations or standards for one or more indicator pollutants, which will ensure the removal of other pollutants present in the wastewater. Based on the information in the record, this approach of establishing effluent limitations and standards on a subset of the pollutants is appropriate for the discharge of FGD wastewater.

The EPA considered the following when selecting a subset of pollutants as indicators for all regulated pollutants:

- The EPA would not set limitations for pollutants associated with treatment system additives because regulating these pollutants could interfere with efforts to optimize treatment system operation.
- The EPA would not set limitations for pollutants for which the treatment technology was ineffective (e.g., pollutant concentrations remained approximately unchanged or increased across the treatment system).
- The EPA would not set limitations for pollutants that are adequately controlled through the regulation of another indicator pollutant because they have similar properties and are treated by similar mechanisms as the regulated pollutant.

The following sections describe EPA's pollutant selection analysis for each of the technology options evaluated for FGD wastewater based on the type of discharge (i.e., direct and indirect).

#### **8.1.1 Direct Dischargers**

As described in the preamble, the proposed rule would establish BAT limitations for the discharge of FGD wastewater based on three different treatment technologies, depending on various subcategorization factors (e.g., low utilization, FGD flow rate). The pollutants considered for regulation by each treatment technology are discussed below.

### Chemical Precipitation

The EPA would establish BAT limitations for two pollutants (arsenic and mercury) based on treatment with chemical precipitation. The regulated pollutant selection criteria matrix for the 32 pollutants present in FGD wastewater is illustrated in Table 8-1. EPA's rationale for selecting which of the pollutants present in FGD wastewater to regulate is described below:

- *Conventional Pollutants.* The EPA identified total suspended solids (TSS) as a pollutant present in FGD wastewater. The existing BPT limitations adequately control TSS in discharges of FGD wastewater.
- *Treatment Chemicals.* The EPA identified and eliminated four pollutants present in FGD wastewater that often are used as treatment chemicals in chemical precipitation systems: aluminum, calcium, iron, and sodium.
- *Pollutants Not Effectively Treated.* The EPA identified nine pollutants which are not reliably removed by chemical precipitation. These pollutants are ammonia, boron, bromide, chloride, cyanide, nitrate/nitrite as N, phosphorus, selenium, and total dissolved solids (TDS).<sup>52</sup>
- *Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants.* The remaining pollutants are metals, metalloids, or other nonmetals. Chemical precipitation systems use chemicals to alter the physical state of dissolved and suspended solids to help settle and remove solids from the wastewater. The metals present in the wastewater form insoluble hydroxides and/or sulfide complexes. The solubilities of these complexes vary by pH; therefore, reaction vessels can be operated at specific pH to enhance removal of specific metals. Most metals are precipitated to some degree in the chemical precipitation system, thereby resulting in the removal of a wide range of metals. The EPA's design basis for the chemical precipitation system includes both hydroxide and sulfide precipitation, as well as iron coprecipitation. For this technology basis, the EPA selected arsenic and mercury as regulated pollutants and as indicators of effective removal of many other pollutants present in FGD wastewater, such as cadmium and chromium.

**Table 8-1. Pollutants Considered for Regulation for FGD Wastewater – Chemical Precipitation**

Pollutant Present in FGD Wastewater	Treatment Chemical	Not Effectively Treated	Directly Regulated or Controlled by Regulation of Another Parameter
Aluminum	✓		
Ammonia		✓	
Antimony			✓

<sup>52</sup> While EPA's pollutant-specific treatment effectiveness analysis performed for FGD wastewater accounts for some removal of ammonia, boron, cyanide, chloride, nitrate/nitrite as N, selenium, and TDS in the chemical precipitation system (see Section 10.2.1.2 for additional details), the EPA has determined that the chemical precipitation system is not demonstrated to reliably treat these pollutants.

**Table 8-1. Pollutants Considered for Regulation for FGD Wastewater – Chemical Precipitation**

Pollutant Present in FGD Wastewater	Treatment Chemical	Not Effectively Treated	Directly Regulated or Controlled by Regulation of Another Parameter
Arsenic			✓
Barium			✓
Beryllium			✓
Boron		✓	
Bromide		✓	
Cadmium			✓
Calcium	✓		
Chloride		✓	
Chromium			✓
Cobalt			✓
Copper			✓
Cyanide		✓	
Iron	✓		
Lead			✓
Magnesium			✓
Manganese			✓
Mercury			✓
Molybdenum			✓
Nickel			✓
Nitrate/Nitrite as N		✓	
Phosphorus		✓	
Selenium		✓	
Sodium	✓		
Thallium			✓
Titanium			✓
Total Dissolved Solids		✓	
Vanadium			✓
Zinc			✓



*Chemical Precipitation followed by Low Residence Time Reduction (CP+LRTR)*

The EPA included BAT limitations for four pollutants (arsenic, mercury, selenium, and nitrate/nitrite as N) based on treatment with CP+LRTR. The regulated pollutant selection criteria matrix for the 32 pollutants present in FGD wastewater is illustrated in Table 8-2. EPA's rationale for selecting which of the pollutants present in FGD wastewater to regulate is described below:

- *Conventional Pollutants.* the EPA identified TSS as a pollutant present in FGD wastewater. The existing BPT limitations adequately control TSS in discharges of FGD wastewater.
- *Treatment Chemicals.* The EPA identified and eliminated five pollutants present in FGD wastewater that are often used as treatment chemicals in CP+LRTR systems: aluminum, calcium, iron, phosphorus, and sodium.
- *Pollutants Not Effectively Treated.* the EPA identified six pollutants which are not reliably removed by CP+LRTR. These pollutants are ammonia, boron, bromide, chloride, cyanide, and TDS.
- *Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants.* The remaining pollutants are metals, metalloids, or other nonmetals and nitrate/nitrite as N. Chemical precipitation systems use chemicals to alter the physical state of dissolved and suspended solids to help settle and remove solids from the wastewater. The CP+LRTR technology basis includes all removal processes identified above for CP, as well as the biological treatment stage. Adding the biological treatment stage provides additional removals of metals (and other pollutants). For example, the bioreactor removes approximately 90 percent of the mercury that remains in FGD wastewater following chemical precipitation treatment. The EPA selected arsenic and mercury as regulated pollutants and as indicators of effective removals of many other pollutants present in FGD wastewater, such as cadmium and chromium. Pollutants such as selenium and nitrate/nitrite as N are not effectively removed by the chemical precipitation process and require additional treatment (e.g., biological treatment) to reliably achieve removal. Anaerobic/anoxic biological treatment is effective at removing both selenium and nitrate/nitrite as N. The EPA selected both of these pollutants, in addition to arsenic and mercury, for regulation under the CP+LRTR technology option.

**Table 8-2. Pollutants Considered for Regulation for FGD Wastewater – CP+LRTR**

Pollutant Present in FGD Wastewater	Treatment Chemical	Not Effectively Treated	Directly Regulated or Controlled by Regulation of Another Parameter
Aluminum	✓		
Ammonia		✓	
Antimony			✓
Arsenic			✓

**Table 8-2. Pollutants Considered for Regulation for FGD Wastewater – CP+LRTR**

Pollutant Present in FGD Wastewater	Treatment Chemical	Not Effectively Treated	Directly Regulated or Controlled by Regulation of Another Parameter
Barium			✓
Beryllium			✓
Boron		✓	
Bromide		✓	
Cadmium			✓
Calcium	✓		
Chloride		✓	
Chromium			✓
Cobalt			✓
Copper			✓
Cyanide		✓	
Iron	✓		
Lead			✓
Magnesium			✓
Manganese			✓
Mercury			✓
Molybdenum			✓
Nickel			✓
Nitrate/Nitrite as N			✓
Phosphorus	✓		
Selenium			✓
Sodium	✓		
Thallium			✓
Titanium			✓
Total Dissolved Solids		✓	
Vanadium			✓
Zinc			✓

*Membrane Filtration*

The EPA included BAT limitations for six pollutants (arsenic, mercury, selenium, nitrate/nitrite as N, bromide, and TDS) based on treatment with membrane filtration. The regulated pollutant selection criteria matrix for the 32 pollutants present in FGD wastewater is illustrated in Table 8-3. EPA's rationale for selecting which of the pollutants present in FGD wastewater to regulate is described below:

- *Conventional Pollutants.* The EPA identified TSS as a pollutant present in FGD wastewater. The existing BPT limitations adequately control TSS in discharges of FGD wastewater.
- *Pollutants Not Effectively Treated:* Based on data for thermal systems and process knowledge and performance data for membrane systems, all pollutants present in FGD wastewater would be effectively treated by membrane filtration.
- *Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants.* The remaining pollutants are metals, metalloids, other nonmetals, nitrate-nitrite as N, chloride, bromide, and TDS. As described in the preamble, the membrane technology evaluated as the technology basis removes pollutants based on their molecular size and solubility. The EPA selected six pollutants (arsenic, mercury, selenium, nitrate-nitrite as N, bromide, and TDS) as regulated pollutants and as indicators of effective removals of all other pollutants present in FGD wastewater.

**Table 8-3. Pollutants Considered for Regulation for FGD Wastewater – Membrane Filtration**

Pollutant Present in FGD Wastewater	Treatment Chemical	Not Effectively Treated	Directly Regulated or Controlled by Regulation of Another Parameter
Aluminum			✓
Ammonia			✓
Antimony			✓
Arsenic			✓
Barium			✓
Beryllium			✓
Boron			✓
Bromide			✓
Cadmium			✓
Calcium			✓
Chloride			✓
Chromium			✓
Cobalt			✓
Copper			✓
Cyanide			✓
Iron			✓
Lead			✓
Magnesium			✓
Manganese			✓
Mercury			✓
Molybdenum			✓

**Table 8-3. Pollutants Considered for Regulation for FGD Wastewater – Membrane Filtration**

Pollutant Present in FGD Wastewater	Treatment Chemical	Not Effectively Treated	Directly Regulated or Controlled by Regulation of Another Parameter
Nickel			✓
Nitrate/Nitrite as N			✓
Phosphorus			✓
Selenium			✓
Sodium			✓
Thallium			✓
Titanium			✓
Total Dissolved Solids			✓
Vanadium			✓
Zinc			✓

### 8.1.2 Indirect Dischargers

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

Section 11 of the 2015 TDD describes EPA’s methodology for conducting the pass-through analysis used for the 2015 rule. As described in Section 6.2.1, the EPA used data from the 2015 rule to characterize pollutant concentrations in the effluent from all three treatment technologies used as the basis for the proposed regulatory option, CP, CP+LRTR, and membrane filtration. As a result, the EPA used the results of the 2015 pass-through analysis to determine which pollutants to regulate for indirect dischargers for this proposed rule.

The data characterizing CP effluent remains unchanged from the 2015 rule; therefore the EPA used the BAT percent removals for mercury and arsenic determined as part of the 2015 rule to determine POTW pass-through based on treatment of FGD wastewater using CP. Table 8-4 presents the current BAT treatment technology removals and POTW removals for FGD wastewater treated using CP. The EPA determined that mercury and arsenic passed through POTW secondary treatment and selected them both as regulated pollutants for PSES based on CP treatment.

**Table 8-4. POTW Pass-Through Analysis - CP**

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	98.9%	65.8%	Yes	Yes
Mercury	99.9%	90.2%	Yes	Yes

Source: U.S. EPA, 2015a.

As described in Section 6.2.1, the overall average effluent quality for CP+LRTR and CP+HRTR technologies is comparable and the EPA applied the pollutant concentrations used to characterize CP+HRTR as estimates for the effluent pollutant concentrations following CP+LRTR. The EPA used the BAT percentage removals for mercury, arsenic, nitrate/nitrite as N, and selenium for PSES from the 2015 rule to determine POTW pass-through based on treatment of FGD wastewater using CP+LRTR. Table 8-5 presents the present BAT treatment technology removals and POTW removals for FGD wastewater treated using CP+LRTR. All four pollutants were determined to pass through POTW secondary treatment and the EPA selected them as regulated pollutants for PSES based on CP+LRTR treatment.

**Table 8-5. POTW Pass-Through Analysis - CP+LRTR**

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	98.9% <sup>a</sup>	65.8%	Yes	Yes
Mercury	99.9% <sup>a</sup>	90.2%	Yes	Yes
Nitrate/Nitrite as N	98.7%	90.0%	Yes	Yes
Selenium	99.8%	34.3%	Yes	Yes

Source: U.S. EPA, 2015a.

a – The arsenic and mercury BAT percent removals presented in this table are based on the chemical precipitation treatment. The CP+LRTR treatment technology will provide even greater removals of these pollutants; however, since pass-through is already demonstrated using CP data, EPA determined that the CP pass-through analysis is sufficient for demonstrating pass-through for CP+LRTR.

As described in Section 6.2.1, the overall average effluent quality for membrane filtration and thermal technologies is comparable and the EPA used the pollutant concentrations used to characterize thermal technologies as estimates for the effluent pollutant concentrations following membrane filtration. The EPA used the BAT percent removals for mercury, arsenic, TDS, and selenium for PSNS from the 2015 rule to determine POTW pass-through based on treatment of FGD wastewater using membrane filtration. The EPA used effluent concentrations from Section 6.2.1 to estimate the BAT removals for bromide and nitrate/nitrite. Table 8-6 presents the current BAT treatment technology removals and POTW removals for FGD wastewater treated using CP+LRTR. All four pollutants were determined to pass through POTW secondary treatment and the EPA selected them as regulated pollutants for PSES based on CP+LRTR treatment.

**Table 8-6. POTW Pass-Through Analysis - Membrane Filtration**

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	96.3%	65.8%	Yes	Yes
Bromide	>98.3% <sup>a</sup>	1.89% <sup>b</sup>	Yes	Yes
Mercury	99.9%	90.2%	Yes	Yes
TDS <sup>c</sup>	99.9%	0%	Yes	Yes
Nitrate/Nitrite as N	>98.7% <sup>d</sup>	90.0%	Yes	Yes
Selenium	99.2%	34.3%	Yes	Yes

Source: U.S. EPA, 2015a.

a – The EPA estimated plant-specific bromide loadings for each plant discharging FGD wastewater using a mass balance approach, as discussed in the memorandum “Mass Balance Approach for Estimating Bromide Loadings in FGD Wastewater” (ERG, 2019). The average total concentration of bromide in discharges from plants that are not burning refined coal and not applying brominated compounds is 59,100 µg/L, and the average total concentration of plants burning refined coal or applying brominated compounds is 167,000 µg/L. Data show that membrane filtration technologies can reduce bromide concentrations to less than 1,000 µg/L. Based on these average concentrations, the EPA calculated a minimum BAT percent removal of 98.3 percent.

b – The EPA expects POTWs may achieve some removal of bromide (e.g., entrainment in treatment residuals); therefore, the EPA set POTW percent removal for bromide equal to the POTW percent removal for bromine.

c – POTWs have not been shown to effectively remove TDS. For this analysis the EPA set POTW percent removal for TDS to zero and assumed this pollutant passes through POTW secondary treatment.

d – The average effluent concentration (Section 6.2.1) and long-term average (Section 8.2.7) for nitrate/nitrite as N in membrane filtration effluent is lower than the average effluent concentration and long-term average calculated for CP+LRTR. As a result BAT removal of nitrate/nitrite as N using membrane filtration will be greater than the BAT removal achieved by CP+LRTR.

## 8.2 CALCULATION OF EFFLUENT LIMITATIONS FOR FGD WASTEWATER

The effluent limitations guidelines and standards are based on long-term average effluent values and variability factors that account for reasonable variation in treatment performance within a particular treatment technology over time. For simplicity, in the remainder of this section, the effluent limitations and/or standards are referred to as “limitations.” Also, the term “option long-term average” and “option variability factor” are used to refer to the long-term averages and variability factors of the treatment technology options for an individual wastestream, rather than the regulatory options described in the preamble.

This section describes the data sources, data selection, and statistical methodology the EPA used to calculate the long-term average, variability factors, and effluent limitations for FGD wastewater.

### 8.2.1 Data Selection

In developing the long-term averages, variability factors, and limitations for a particular wastestream and technology option, the EPA used wastewater data from plants operating the model treatment technology forming the basis of a particular technology option. The data sources evaluated include: (1) a sampling program during which the EPA collected samples (hereinafter

referred to as “EPA sampling”); (2) a sampling program during which the EPA, pursuant to section 308 of the Clean Water Act, directed plants to collect samples (hereinafter referred to as “CWA 308 sampling”); and (3) self-monitoring data that plants collected and analyzed (hereinafter referred to as “plant self-monitoring”).

### *Data Selection Criteria*

This section describes the criteria that the EPA applied in selecting plants and data to use as the basis for the numeric limitations for FGD wastewater. The EPA has used these, or similar criteria, in developing limitations for other industries. The EPA uses these criteria to select data that reflect performance of the model technology in treating the industrial wastes under normal operating conditions.

The first criterion requires that the plant have the model technology and that it is generally well operated. Applying this criterion typically eliminates any plant with treatment other than the model technology. The EPA generally determines whether a plant meets this criterion based on site visits, discussions with plant management, engineering reports, and/or comparison to the characteristics, operation, and performance of treatment systems at other plants. When warranted, the EPA also contacts plants as it evaluates whether data submitted represented normal operating conditions for the plant and equipment.

The second criterion requires that the influents and effluents from the treatment components represent typical wastewater from the industry, without incompatible wastewater from other sources. Applying this criterion enables the EPA to select only those plants where the commingled wastewaters are not characterized by substantial dilution, sudden large variation in wastewater flow rates (i.e., slug loads) that can result in frequent upsets and/or overloads, or wastewaters with different types of pollutants than those generated by the waste stream for which the EPA is establishing effluent limitations.

The third criterion ensures that the pollutants are present in the influent at sufficient concentrations to evaluate treatment technology effectiveness. To evaluate whether the data meet this criterion for the final rule, the EPA often uses a long-term average test (or LTA test) for plants where the EPA possesses both influent and effluent data. The EPA has used this test in developing regulations for other industries (e.g., the ELGs for the Iron and Steel Point Source Category) (U.S. EPA, 2002) and was also used when developing effluent limitations for the 2015 rule. The test measures the influent concentrations to ensure a pollutant is present at concentrations high enough to evaluate treatment effectiveness. If a data set for a pollutant fails the test, the EPA excludes the data for that pollutant at that plant when calculating the limitations.

The fourth criterion requires that the data are valid and appropriate for their intended use (e.g., the data must be analyzed with a sufficiently sensitive method). Also, the EPA does not use data associated with periods of treatment upsets because such data do not reflect the performance of well-operated treatment systems. In applying the fourth criterion, the EPA may evaluate the pollutant concentrations, analytical methods and the associated quality control/quality assurance data, flow values, mass loadings, plant logs, and other available information. As part of this evaluation, the EPA reviews the process or treatment conditions that may have resulted in

extreme values (high and low). Consequently, the EPA may exclude data associated with certain time periods or other data outliers that reflect poor performance or analytical anomalies by an otherwise well-operated site.

The EPA also applies the fourth criterion in its review of data corresponding to the initial commissioning period for treatment systems. When installing a new treatment system, most industries undergo a commissioning period to acclimate and optimize the system. During this acclimation and optimization process, the effluent concentration values can be highly variable with occasional extreme values (high and low). This occurs because the treatment system typically requires some “tuning” as the plant staff and equipment and chemical vendors work to determine the optimum chemical addition locations and dosages, vessel hydraulic residence times, internal treatment system recycle flows (e.g., filter backwash frequency, duration, and flow rate; return flows between treatment system components), and other operational conditions, including clarifier sludge wasting protocols. The initial commissioning period may be as short as several days, but depending on the technology employed, it may also take treatment system operators several weeks or months to gain expertise in operating the new treatment system. This contributes to treatment system variability during the commissioning period. After this initial adjustment period, the system should operate at steady state with relatively low variability around a long-term average over many years. Because commissioning periods typically reflect operating conditions unique to the first time the treatment system begins operation, the EPA typically excludes such data in developing the limitations.<sup>53</sup>

Similarly, power plant decommissioning periods represent unique operating conditions associated with the permanent shutdown of the power plant, FGD system, and FGD wastewater treatment system,<sup>54</sup> and do not represent best available control technology economically

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<sup>53</sup> Examples of conditions that are typically unique to the initial commissioning period include operator unfamiliarity or inexperience with the system and how to optimize/adjust its performance to deal with influent wastewater variability and changing conditions, as well as the initial startup of newly installed equipment to ensure components operate as intended. 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 (e.g., on the order of days, weeks, or even months). In this latter situation, the plant has already established typical operating practices and set points for treatment system components and operators have experience operating the treatment system and adjusting its operation to deal with changing conditions. Any variability unique to restarting the treatment system can be accommodated, if necessary, by operational practices that include closer monitoring of treatment system operating parameters and recirculating any off-specification effluent back through the treatment system.

<sup>54</sup> Note that decommissioning periods for an individual generating unit at a multi-unit plant are not the same as a plant decommissioning period because wastes from normal operation of the remaining unit(s) will continue. Examples of conditions that are unique to the power plant decommissioning periods include the complete shutdown, cleaning, decommissioning, and possibly dismantling of the equipment and processes used to generate electricity (e.g., boiler operations) which is likely to cause erratic operation of the treatment system. In addition, plant decommissioning would include draining and decommissioning the treatment system itself. These conditions differ from those associated with the periodic shutdown of generating units and other systems at a plant, whether they be for short or extended duration shutdown (e.g., on the order of days, weeks, or even months). In this latter situation, the plant has already established typical operating practices and set points for treatment system components and operators have experience operating the treatment system and adjusting its operation to deal with changing conditions. Any variability unique to the shutdown period can be accommodated, if necessary, by operational practices that include closer monitoring of treatment system operating parameters and recirculating any off-specification effluent back through the treatment system.



achievable (BAT) level of performance for treatment of FGD wastewater at an operating steam electric power plant. Therefore, the EPA also excludes data collected during the plant decommissioning period in calculating the limitations.

#### *Data Selection for Each Technology Option*

This section summarizes the data used in developing the proposed limitations for each FGD wastewater technology option. See the preamble for a description of the technology options. Three technology options were evaluated for this proposed rule: chemical precipitation; the combination of chemical precipitation and LRTR biological treatment; and membrane filtration. In certain instances, the proposed rule would establish limitations for wastewater discharges that are equal to previously established best practicable control technology currently available limitations for total suspended solids (TSS). The EPA used no new effluent concentration data to establish these limitations and therefore, such limitations are not discussed in this section. The data sources listed below were used to calculate the proposed effluent limitations for each technology option.

- *Chemical Precipitation Technology.* Four plants operating installed chemical precipitation treatment systems that include hydroxide precipitation, sulfide precipitation, and iron coprecipitation.
- *CP+LRTR Technology.* Five data sets from plants operating a pilot treatment system that includes chemical precipitation followed by LRTR anoxic/anaerobic biological treatment designed to remove selenium and nitrate-nitrite.
- *Membrane Filtration Technology.* Three data sets from plants operating a pilot membrane filtration treatment systems that include pretreatment (largely to reduce suspended solids before reverse osmosis) and reverse osmosis.

#### *Combining Data from Multiple Sources within a Plant*

For this rulemaking, data for plants used for chemical precipitation limitations came from multiple sources, including the EPA sampling, CWA 308 sampling, and plant self-monitoring. For three plants (Hatfield's Ferry, Miami Fort, and Pleasant Prairie), data from multiple sources were collected during overlapping time periods and the EPA combined these data into a single data set for the plant. For one plant (Keystone), the multiple sources of data were collected during non-overlapping time periods. At Keystone, the EPA and CWA 308 samples were collected from September 2010 through January 2011 and arsenic self-monitoring data were available from January 2012 through April 2014. The EPA has no information to indicate that these time periods represent different operating conditions; therefore, the EPA also combined the multiple sources of data for Keystone into a single data set for the plant. This approach is consistent with EPA's traditional approach for other effluent guidelines rulemakings.<sup>55</sup> For each

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<sup>55</sup> When the EPA obtains data from multiple sources (such as the EPA sampling, CWA 308 sampling, and plant self-monitoring data in this rulemaking) from a plant for the same time period, the EPA usually combines the data from these sources into a single data set for the plant for the statistical analyses. In some cases where the sampling data from a plant are collected over two or more distinct time periods, the EPA may analyze the data from each time period separately. In some past effluent guideline rulemakings, the EPA analyzed data as if each time period

of the plants used for the CP+LRTR and membrane filtration limitations, the data were collected from a single source (i.e., plant self-monitoring), so it was not necessary to combine data.

### **8.2.2 Data Exclusions and Substitutions**

The sections below describe why and how the EPA either excluded or substituted certain data in calculating the limitations.

#### *Data Exclusions*

After selecting the model plant(s), the EPA applied the data selection criteria described in Section 8.2.1 by evaluating all available data for each model plant. The EPA identified certain data that warranted exclusion from calculating the limitations because: (1) the samples were analyzed using an analytical method that is not approved in 40 CFR 136 for National Pollutant Discharge Elimination System (NPDES) purposes; (2) the samples were analyzed using a method that was not a sufficiently sensitive analytical method (e.g., the EPA Method 245.1 for mercury in effluent samples); (3) the samples were analyzed in a manner that resulted in an unacceptable level of analytical interferences; (4) the samples were collected prior to steady state operation, during the initial commissioning period for the treatment system, or during the plant decommissioning period; (5) the analytical results were identified as questionable due to quality control issues, abnormal conditions or treatment upsets, or were analytical anomalies; (6) the samples were collected from a location that is not representative of treated effluent (e.g., secondary clarifier instead of final effluent); or (7) the treatment system was operating in a manner that does not represent BAT/NSPS level of performance.

#### *Data Substitutions*

In general, the EPA used detected values or, for non-detected values, sample-specific detection limits (i.e., sample-specific quantitation limit, or QL) in calculating the limitations.<sup>56</sup> However, there were some instances in which the EPA substituted a baseline value for a detected value or a sample-specific detection limit that was lower than the baseline value. Baseline substitution accounts for the possibility that certain detected or non-detected results may be at a lower concentration than generally can be reliably quantified by well-operated laboratories. This approach is consistent with how the EPA has calculated limitations in previous effluent guidelines rulemakings and is intended to avoid establishing an effluent limitation that could be biased toward a lower concentration than plants can reliably demonstrate compliance.<sup>57</sup> After

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represented a different plant when the data were considered to represent fundamentally different operating conditions. This was not the case for the Keystone data, so the EPA combined all data for the plant into a single data set.

<sup>56</sup> For the purpose of the discussion of calculating the long-term averages, variability factors, and effluent limitations, the term “detected” refers to analytical results measured and reported above the sample-specific quantitation limit (QL). The term “non-detected” refers to values that are below the method detection limit (MDL) and also those measured by the laboratory as being between the MDL and the QL.

<sup>57</sup> For example, if a limit were established at a concentration lower than the baseline value, although some laboratories might be able to achieve sufficiently low quantitation levels, it is possible that typical well-operated laboratories could not reliably measure down to that level. In such cases, a plant would not be able to demonstrate compliance with the limit. The EPA does not suggest that the baseline value should be established at a level that

excluding all the necessary data as described above, the EPA compared each reported result to a baseline value. Whenever a detected value or sample-specific detection limit was lower than the baseline value, the EPA used the baseline value instead and classified the value as non-detected (even if the actual reported result was a detected value). For example, if the baseline value was 5 micrograms/liter ( $\mu\text{g/L}$ ) and the laboratory reported a detected value of 3  $\mu\text{g/L}$ , EPA's calculations would treat the sample result as being non-detected with a sample-specific detection limit of 5  $\mu\text{g/L}$ .

The EPA used the following baseline values for each pollutant in the development of the effluent limitations for the steam electric rulemaking:

- Arsenic: 2  $\mu\text{g/L}$ .
- Mercury: 0.5 nanogram/liter (ng/L).
- Nitrate-nitrite as N: 0.05 milligram/liter (mg/L).
- Selenium: 5  $\mu\text{g/L}$ .
- TDS: 10 mg/L
- Bromide: 0.01 mg/L.

The EPA determined the baseline values for mercury, nitrate-nitrite as N, and TDS using the minimum levels (MLs) established by the analytical methods used to obtain the reported values or a comparable analytical method where an ML was not specified by the method.<sup>58</sup> The baseline values for arsenic and selenium are based on the results of MDL studies conducted by well-operated commercial laboratories using the EPA Method 200.8 to analyze samples of synthetic FGD wastewater (CSC, 2013).

In cases when all concentration values are above the baseline value, then the baseline value has no effect on the concentration values and subsequent calculated limitations.

In addition to calculating the limitations for each technology option (adjusting for the baseline values shown above, when appropriate), the EPA also calculated effluent limitations using all the valid reported results (i.e., without substituting baseline values and/or changing the censoring classification of the result). As noted above, the reason for substituting baseline values is to prevent establishing an effluent limitation that is biased toward a lower concentration than plants can reliably demonstrate compliance with. Because the EPA wanted to ensure that plants can achieve the effluent limitations established by the rule, the EPA calculated and evaluated both

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every laboratory in the country can measure to, nor that limitations established for the ELGs must be established sufficiently high that every laboratory in the country must be able to measure to that concentration; however, it is appropriate to use baseline values that generally can be reliably quantified by well-operated laboratories. This approach achieves a reasonable balance in establishing limitations that are representative of treatment system performance and protective of the environment, while at the same time ensuring that plants have adequate access to laboratories with the analytical capabilities necessary to reliably demonstrate compliance with the limitations.

<sup>58</sup> The baseline values for mercury and nitrate-nitrite as N are equal to the MLs specified in the EPA Methods 1631E and 353.2, respectively. The method the EPA used to analyze for TDS (Standard Method 2540C) does not explicitly state an MDL or ML. However, the EPA Method 160.1 is similar to Standard Method 2540C and the lower limit of its measurement range is 10 mg/L (i.e., the nominal quantitation limit). Thus, the EPA used 10 mg/L as the baseline value for TDS. The baseline value for bromide is based on EPA Method 300.0.

the baseline-adjusted and unadjusted limitations for each technology option and used the higher of the two results for the final ELGs.

### **8.2.3 Data Aggregation**

The EPA used daily values in developing the limitations. In cases with at least two samples per day, the EPA aggregated the sample results to obtain a single value for that day. There are instances where the sampling data used in this rulemaking includes multiple sample results for a given day. This occurred with field duplicates, overlaps between plant self-monitoring and the EPA sampling, or overlaps between plant self-monitoring and CWA 308 sampling.

When aggregating the data, the EPA took into account whether each value was detected (D) or non-detected (ND). Measurements reported as being less than the sample-specific detection limit (or baseline values, as appropriate) are designated as non-detected (ND) for the purpose of statistical analyses to calculate the limitations. In the tables and data listings in this document and in the rulemaking record, the EPA uses the indicators D and ND to denote the censoring type for detected and non-detected values, respectively.

The sections below describe each of the different aggregation procedures. They are presented in the order that the aggregation was performed (i.e., field duplicates were aggregated first and then any overlaps between plant self-monitoring and the EPA sampling data or CWA 308 sampling were aggregated).

#### *Aggregation of Field Duplicates*

During the EPA sampling, the EPA collected duplicate field samples as part of the quality assurance/quality control activities. Field duplicates are two samples collected for the same sampling point at approximately the same time. The duplicates are assigned different sample numbers, and they are flagged as duplicates for a single sampling point at a plant. Because the analytical data from a duplicate pair are intended to characterize the same conditions at a given time at a single sampling point, the EPA averaged the data to obtain one value for each duplicate pair.

For arsenic at Hatfield's Ferry and arsenic and mercury from Miami Fort, there were a few days with two or three reported self-monitoring samples. These self-monitoring samples from the same day were treated as duplicate samples in the calculations.

In most cases, the duplicate samples had the same censoring type, so the censoring type of the aggregated value was the same as that of the duplicates. In some instances, one duplicate was a detected (D) value and the other duplicate was a non-detected (ND) value. When this occurred, the EPA determined that the aggregated value should be treated as detected (D) because the pollutant is confirmed to be present at a level above the sample-specified detection limit in one of the duplicates.

Table 8-7 summarizes the procedure for aggregating the sample measurements from the field duplicates. Aggregating the duplicate pairs was the first step in the aggregation procedures for both influent and effluent measurements.

**Table 8-7. Aggregation of Field Duplicates**

If the Field Duplicates Are:	Censoring Type of Average Is:	Aggregated Values	Formulas for Aggregated Values
Both Detected	D	Arithmetic average of measured values.	$(D_1 + D_2)/2$
Both Non-Detected	ND	Arithmetic average of sample-specific detection limit (or baseline).	$(DL_1 + DL_2)/2$
One Detected and One Non-Detected	D	Arithmetic average of measured value and sample-specific detection limit (or baseline).	$(D + DL)/2$

D – Detected.

ND – Non-detected.

DL – Sample-specific detection limit.

### *Aggregation of Overlapping Samples*

For the chemical precipitation data collected from the Hatfield’s Ferry, Miami Fort, and Pleasant Prairie plants, sampling data were available from the EPA sampling, CWA 308 sampling, and plant self-monitoring. As explained in Section 8.2.1, there was some overlap between the data from these sources. On some days at a given plant, samples were available from two sources, specifically plant self-monitoring and either the EPA sampling or CWA 308 sampling. When these overlaps occurred, the EPA aggregated the measurements from the available samples by averaging them to obtain one value for that day.

When both measurements had the same censoring type, then the censoring type of the aggregate was the same as that of the overlapping values. When one or more measurements were detected (D), the EPA determined that the appropriate censoring type of the aggregate was detected because the pollutant was confirmed to be present at a level above the sample-specific detection limit in one of the samples. The procedure for obtaining the aggregated value and censoring type is similar to the procedure shown in Table 8-7.

### **8.2.4 Data Editing Criteria**

After excluding and aggregating the data, the EPA applied data editing criteria on a pollutant-by-pollutant basis to select the data sets to be used for developing the limitations for each technology option. These criteria are referred to as the long-term average test (LTA test). The EPA often uses the LTA test to ensure that the pollutants are present in the influent at sufficient concentrations to evaluate treatment effectiveness at the plant for the purpose of calculating effluent limitations. By applying the LTA test, the EPA ensures that the limitations result from treatment of the wastewater and not simply the absence or substantial dilution of that pollutant in the wastestream. For each pollutant for which the EPA calculated a limitation, the influent first had to pass a basic requirement: the pollutant had to be detected—at any concentration—by 50 percent of the influent measurements. If the data set at a plant passed the basic requirement, then the data had to pass one of the following two criteria to pass the LTA test:

- Criterion 1. At least 50 percent of the influent measurements in a data set at a plant were detected at levels equal to or greater than 10 times the baseline value described in Section 8.2.2.

- Criterion 2. At least 50 percent of the influent measurements in a data set at a plant were detected at any concentration and the influent arithmetic average was equal to or greater than 10 times the baseline value (described in Section 8.2.2).

If the data set at a plant failed the basic requirement, then the EPA automatically set both Criteria 1 and 2 to “fail,” and it excluded the plant’s effluent data for that pollutant when calculating limitations. If the data set for a plant failed the basic requirement, or passed the basic requirement but failed both criteria, the EPA would exclude the plant’s effluent data for that pollutant when calculating limitations.

After performing the LTA test for the regulated pollutants at each model plant representing the relevant technology option, the EPA found all chemical precipitation data sets passed the LTA test and all LRTR and membrane filtration data sets passed the LTA test, except for the following:

- Arsenic failed the LTA test at plants 2027 and 2066 in the LRTR data sets.
- Nitrate-nitrite as N failed the LTA test for plant 2097 in the LRTR data sets.
- Arsenic failed the LTA test for plants 4058 and 4060 in the membrane data sets.

For those plants where a pollutant failed the LTA test, the associated effluent data for that plant was excluded from the calculation of the long-term average, variability factors, and effluent limitations.

### **8.2.5 Overview of Limitations**

The preceding sections discussed the data selection, data exclusions and substitutions, data aggregation, as well as the data editing procedures that the EPA used to identify the daily values for calculating effluent limitations. This section describes EPA’s objectives for the daily maximum and monthly average effluent limitations, the selection of percentiles for those limitations, and compliance with the limitations.

#### *Objectives*

The EPA’s objective in establishing daily maximum limitations is to restrict discharges on a daily basis at a level that is achievable for a plant that targets its treatment at the long-term average.<sup>59</sup> The EPA recognizes that variability around the long-term average occurs during normal operations, which means that plants might, at times, discharge at a level that is higher (or lower) than the long-term average. To allow for occasional discharges that are at a higher concentration than the long-term average, the EPA establishes a daily maximum limitation. A plant that consistently discharges at a level near the daily maximum limitation would not be operating its treatment system to achieve the long-term average. Targeting treatment to achieve

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<sup>59</sup> Put simply, the long-term average is the average concentration that is achieved over a period of time. Statistically, the long-term average is the mean of the underlying statistical distribution of the daily effluent values. The long-term average is used along with other information about the distribution of the effluent data to calculate the effluent limitations.

the daily maximum limitations, rather than the long-term average, might result in values that frequently exceed the limitations due to routine variability in treated effluent.

The EPA's objective in establishing monthly average limitations is to provide an additional restriction to help ensure that plants target their average discharges to achieve the long-term average. The monthly average limitation requires dischargers to provide ongoing control, on a monthly basis, that supplements controls to achieve the daily maximum limitation. 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. For the plant to achieve compliance, these values must result in a monthly average value that is equal to or below the monthly average limitation.

### *Selection of Percentiles*

The EPA calculates effluent limitations based on percentiles that should be both high enough to accommodate reasonably anticipated variability within control of the plant, and low enough to reflect a level of performance consistent with the CWA requirement that these effluent limitations be based on the best available technology or best available demonstrated control technology. The daily maximum limitation is an estimate of the 99<sup>th</sup> percentile of the distribution of the *daily* measurements. The monthly average limitation is an estimate of the 95<sup>th</sup> percentile of the distribution of the *monthly* averages of the daily measurements.

The EPA uses the 99<sup>th</sup> and 95<sup>th</sup> percentiles to draw a line at a definite point in the statistical distributions that would ensure that plant operators work to establish and maintain the appropriate level of control. These percentiles reflect a longstanding Agency policy judgment about where to draw the line. The development of the limitations takes into account the reasonably anticipated variability in discharges that may occur at a well-operated plant. By targeting its treatment at the long-term average, a well-operated plant will be able to comply with the effluent limitations at all times because the EPA has incorporated an appropriate allowance for variability in the limitations.

The EPA's methodology for establishing effluent limitations based on certain percentiles of the statistical distributions may give the impression that the EPA expects occasional exceedances of the limitations. This conclusion is incorrect. The EPA promulgates limitations that plants are capable of complying with at all times by properly operating and maintaining their treatment technologies. These limitations are based on statistical modeling of the data and engineering review of the limitations and data.

Statistical methodology is used as a framework to establish limitations based on percentiles of the effluent data. Statistical methods provide a logical and consistent framework for analyzing a set of effluent data and determining values from the data that form a reasonable basis for effluent limitations. In conjunction with the statistical methods, the EPA performs an engineering review to verify that the limitations are reasonable based on the design and expected operation of the treatment technologies and the plant process conditions. As part of that review, the EPA examines the range of performance reflected in the plant data sets used to calculate the limitations. The plant data sets represent operation of a treatment technology that represents the best available technology or best available demonstrated control technology. In some cases,

however, although these plants were operating a model technology, these data sets, or periods of time within a data set, may not necessarily represent the optimized performance of the technology. As described in Section 8.2.2, the EPA excluded certain data from the data sets used to calculate the effluent limitations. At the same time, however, the data sets used to calculate effluent limitations still retain some observations that likely reflect periods of less than optimal performance. The EPA retained these data in developing the limitations because they help to characterize the variability in treatment system effluent. Based on the combined statistical modeling and engineering review used to establish the limitations, plants are expected to design and operate their treatment systems in a manner that will ensure compliance with the limitations. The EPA does not expect plants to operate their treatment systems to violate the limitations at some pre-set rate merely because probability models are used to develop limitations.

### **8.2.6 Calculation of The Limitations**

The EPA calculated the limitations by multiplying the long-term average by the appropriate variability factors. In deriving the limitations for a pollutant, the EPA first calculates an average performance level (the “option long-term average,” discussed below) that a plant with well-designed and well-operated model technology is capable of achieving. This long-term average is calculated using data from the model plant (plants with the model technologies) for the technology option.

In the second step of developing a limitation for a pollutant, the EPA determines an allowance for the variation (the “option variability factor” discussed below) in pollutant concentrations for wastewater that has been processed through a well-designed and well-operated treatment system(s). This allowance for variation incorporates all components of potential variability, including sample collection, sample shipping and storage, and analytical variability. The EPA incorporates this allowance into the limitations by using the variability factors that are calculated using data from the model plants. If a plant operates its treatment system to meet the relevant long-term average, the EPA expects the plant will be able to meet the limitations. Variability factors provide an additional assurance that normal fluctuations in a plant’s treatment process are appropriately accounted for in the limitations. By accounting for these reasonable excursions above the long-term average, EPA’s use of variability factors results in effluent limitations that are above the long-term averages.

The following sections describe derivation of the option long-term averages, option variability factors and limitations, and the adjustment made for autocorrelation in the calculation of the limitations for this proposed rulemaking. For information regarding the derivation of limitations for the 2015 rule, see Section 13 of the 2015 TDD.

#### *Calculation of Technology Option Long-Term Average*

The EPA calculated the technology option long-term average for a pollutant in two steps. First, the EPA calculated the plant-specific long-term average for each pollutant that had enough distinct detected values by fitting a statistical model to the daily concentration values. In cases when a data set for a specific pollutant does not have enough distinct detected values to use the statistical model, the plant-specific long-term average for each pollutant is the arithmetic mean of the available daily concentration values. Appendix B of the 2015 TDD presents an overview of



the statistical model and describes the procedures the EPA used to estimate the plant-specific long-term average.

Second, the EPA calculated the option long-term average for a pollutant as the *median* of the plant-specific long-term averages for that pollutant. The median is the midpoint of the values when ordered (i.e., ranked) from smallest to largest. If there are an odd number of values, then the value of the  $m^{\text{th}}$  ordered observation is the median (where  $m=(n+1)/2$  and  $n$ =number of values). If there are an even number of values, then the median is the average of the two values in the  $n/2^{\text{th}}$  and  $[(n/2)+1]^{\text{th}}$  positions among the ordered observations.

#### *Calculation of Option Variability Factors and Limitations*

The following describes the calculations performed to derive the option variability factors and limitations. First, the EPA calculated the plant-specific variability factors for each pollutant that had enough distinct detected values by fitting a statistical model to the daily concentration values. Each plant-specific daily variability factor for each pollutant is the estimated 99<sup>th</sup> percentile of the distribution of the daily concentration values divided by the plant-specific long-term average. Each plant-specific monthly variability factor for each pollutant is the estimated 95<sup>th</sup> percentile of the distribution of the 4-day average concentration values divided by the plant-specific long-term average. The calculation of the plant-specific monthly variability factor assumes that the monthly averages are based on the pollutant being monitored weekly (approximately four times each month). In cases when there were not enough distinct detected values for a specific pollutant at a specific plant, then the statistical model was not used to obtain the variability factors for that plant. In these cases, the EPA excluded the data for the pollutant at the plant from the calculation of the option monthly variability factors. Appendix B of the 2015 TDD describes the procedures used to estimate the plant-specific daily and monthly variability factors.

Next, the EPA calculated the option daily variability factor for a pollutant as the *mean* of the plant-specific daily variability factors for that pollutant. Similarly, the option monthly variability factor was the mean of the plant-specific monthly variability factors for that pollutant.

Finally, the EPA calculated the daily maximum limitations for each pollutant for each technology option by multiplying the option long-term average and option daily variability factors. The monthly average limitations for each pollutant for each technology option are the product of the option long-term average and option monthly variability factors.

#### *Adjustment for Autocorrelation*

Effluent concentrations that are collected over time may be autocorrelated. The data are positively autocorrelated when measurements taken at specific time intervals, such as one or two days apart, are more similar than measurements taken far apart in time. For example, positive autocorrelation would occur if the effluent concentrations were relatively high one day and were likely to remain high on the next and possibly succeeding days. Because the autocorrelated data affect the true variability of treatment performance, the EPA typically adjusts the variance estimates for the autocorrelated data, when appropriate.

For this rulemaking, whenever there were sufficient data for a pollutant at a plant to evaluate the autocorrelation reliably, the EPA estimated the autocorrelation and incorporated it into the calculation of the limitations. For a plant without enough data to reliably estimate the autocorrelation, when there was a correlation of a pollutant available from a similar technology and wastestream and the pollutant removal processes were similar, the EPA transferred the autocorrelation estimates from that treatment technology. Otherwise, the EPA set the autocorrelation to zero in calculating the limitations, because the Agency did not have sufficient data to reliably evaluate whether the data were autocorrelated or to determine whether a valid autocorrelation estimate could be transferred from a similar technology and wastestream. The following paragraphs describe the instances where the EPA was able to estimate autocorrelation and the assumptions made about the autocorrelation when there were too few observations to estimate the possible autocorrelation.

For the chemical precipitation treatment option for FGD wastewater, the EPA was able to perform a statistical evaluation of the autocorrelation and obtain a reliable estimate of the autocorrelation. Table 8-8 lists the autocorrelation values used in the limitations calculation for arsenic and mercury for the chemical precipitation option.

For the LRTR treatment technology for FGD wastewater, the EPA was able to perform a statistical evaluation and obtain a reliable estimate of the autocorrelation for selenium and mercury because enough data were available for these pollutants. Because of the similarities between the pollutant removal processes, the EPA determined that it would be appropriate to also use the values estimated for selenium and mercury as the autocorrelation estimates for nitrate-nitrite as N and arsenic, respectively. Table 8-8 below lists the autocorrelation values used in the limitations calculation for arsenic, mercury, nitrate-nitrite as N and selenium for the LRTR treatment option.

For the membrane treatment option for FGD, the EPA was not able to perform a statistical evaluation of the autocorrelation and obtain a reliable estimate of the autocorrelation because there were too few detected observations available. Thus, for this technology option, the EPA set the autocorrelation to zero in the calculation of the limitations. The EPA did so because there were not sufficient data to reliably evaluate the autocorrelation, nor did the EPA have a valid correlation estimate available that could be transferred from a similar technology and wastestream.

**Table 8-8. Autocorrelation Values Used in Calculating Limitations for FGD Wastewater**

Treatment Technology	Pollutant	Correlation Value Used to Calculate Limitation
CP+LRTR	Arsenic	0.53
	Mercury	0.53
	Selenium	0.66
	Nitrate-nitrite as N <sup>a</sup>	0.66
Chemical Precipitation	Arsenic <sup>b</sup>	0.86

**Table 8-8. Autocorrelation Values Used in Calculating Limitations for FGD Wastewater**

Treatment Technology	Pollutant	Correlation Value Used to Calculate Limitation
	Mercury	0.89

a – There were not enough detected values for nitrate-nitrite as N, so the EPA was not able to directly calculate the autocorrelation. However, the EPA transferred the autocorrelation from selenium because these two chemicals behave similarly in the biological treatment system.

b – There were not enough detected values for arsenic, so the EPA was not able to directly calculate the autocorrelation. However, the EPA transferred the autocorrelation from mercury because these two chemicals behave similarly in a properly operated chemical-biological treatment system using all aspects of the CP+LRTR technology.

### **8.2.7 Long-Term Averages and Effluent Limitations for FGD Wastewater**

Table 8-9 presents the proposed effluent limitations for discharges of FGD wastewater. As described in Section 8.2.2, the EPA evaluated what the limitations would be using baseline substitution, as well as what the limitations would be without adjusting for baseline substitution. The limitations presented for the proposed rule use the higher result. Table 8-9 also presents the long-term average treatment performance calculated for the selected treatment technology option. Due to routine variability in treated effluent, a power plant that targets its treatment to achieve pollutant concentrations at a level near the values of the daily maximum limitation or the monthly average limitation may experience frequent values exceeding the limitations. For this reason, the EPA recommends that plants design and operate the treatment system to achieve the long-term average for the model technology. In doing so, a system that is designed to represent the BAT level of control would be expected to meet the limitations.

**Table 8-9. Long-Term Averages and Effluent Limitations for FGD Wastewater**

Treatment Technology Basis	Pollutant	Long-Term Average	Daily Maximum Limitation	Monthly Average Limitation
CP+LRTR <sup>a</sup>	Arsenic (µg/L)	5.07	18	9
	Mercury (ng/L)	13.5	85	31
	Nitrate-nitrite as N (mg/L)	2.62	4.6	3.2
	Selenium (µg/L)	16.6	76	31
Membrane Filtration (Voluntary Incentives Program)	Arsenic (µg/L)	5.0 <sup>b</sup>	5 <sup>c</sup>	--- <sup>d</sup>
	Mercury (ng/L)	5.08	21	9
	Nitrate-nitrite as N (mg/L)	0.40	1.1	0.6
	Selenium (µg/L)	5.0	21	11
	Bromide (mg/L)	0.163	0.6	0.3
	TDS (mg/L)	88.0	351	156
Chemical Precipitation (High Flow and Low Utilization Subcategories)	Arsenic (µg/L)	5.98	11	8
	Mercury (ng/L)	159	788	356

a – The CP+LRTR effluent limitations would apply to all plants not in the Voluntary Incentives Program, High Flow Subcategory, or Low Utilization Subcategory.

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

c – Limitation is set equal to the quantitation limit for the evaluated data set(s).

d – The EPA is not establishing monthly average limitations when the daily maximum limitation is based on the quantitation limit.

### 8.3 SELECTION OF REGULATED POLLUTANTS FOR BOTTOM ASH TRANSPORT WATER

Section 6.3.1 describes the pollutants present in bottom ash transport water. To the extent that the proposed regulatory options are eliminating or nearly eliminating the discharge of bottom ash transport water through high rate recycle, the discharge of all pollutants present in bottom ash transport water will decrease and therefore be regulated.

### 8.4 EFFLUENT LIMITATIONS FOR BOTTOM ASH TRANSPORT WATER

As described in the preamble, the EPA is proposing a pollutant discharge allowance in the form of a maximum percentage purge rate for bottom ash transport water. To develop this allowance, the EPA first collected data that could be used to estimate the volume of wastewater that a plant operating a high recycle rate system may need to discharge to either better facilitate managing the water balance or to adjust water chemistry by diluting the transport water remaining in the bottom ash system.<sup>60</sup>

Specifically, the EPA reviewed a report that presents discharge data from seven currently operating wet bottom ash transport water systems at six plants. These plants were able to recycle most or all bottom ash transport water from these seven systems, resulting in discharges of

<sup>60</sup> Although the technology basis includes dry handling, the limitation is based on the necessary purge volumes of a wet, high recycle rate bottom ash system.

between zero and two percent of the system volume (EPRI, 2016). In order to account for infrequent precipitation and maintenance events, in addition to the proposed purge rate, the EPA reviewed hypothetical maximum discharge volumes and the estimated frequency associated with such infrequent events for wet bottom ash systems (EPRI, 2018).<sup>61</sup>

To estimate the allowance percentage associated with such infrequent events, the EPA divided the hypothetical discharge associated with an assumed maintenance and precipitation event by the volume of the transport water system, and then averaged the resulting percent over 30 days.

Finally, the EPA added each reported regular discharge percent for the seven operating systems to the hypothetical 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 hypothetical discharge scenarios are reported in Table 8-10 below. The EPA selected a 95th percentile of the data distribution (approximately 10 percent of total system volume) as representative of the 30-day rolling average.

**Table 8-10. Thirty-Day Rolling Average Discharge Volume as a Percent of System Volume<sup>a</sup>**

Infrequent Discharge Needs		Regular Discharge For Purpose of Adjusting Water Chemistry and/or Water Balance						
		Plant A	Plant B	Plant C	Plant D	Plant E	Plant F-System1	Plant F-System2
Type of Infrequent Discharge Event	30-Day Average							
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%

Source: EPRI, 2016; EPRI, 2018.

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

This proposed rule includes BAT effluent limitations and standards on any wastewater purged from a high recycle rate system established by the permitting authority on a case-by-case basis using BPJ.

## 8.5 REFERENCES

1. CSC. 2013. Computer Sciences Corporation. Results of the ICP/MS Collision Cell Method Detection Limit Studies in the Synthetic Flue Gas Desulfurization Matrix. (16 January). DCN SE03872.
2. EPRI. 2016. Electric Power Research Institute. *Guidance Document for Management of Closed-Loop Bottom Ash Handling Water in Compliance with the 2015 Effluent Limitations Guidelines (ELGs)*. Palo Alto, CA. (December). DCN SE06963.

<sup>61</sup> The EPA did not consider events such as pipe leaks as these would not be reflective of proper system operation.

3. EPRI. 2018. Electric Power Research Institute. *Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges*. Palo Alto, CA. (September). DCN SE06920.
4. U.S. EPA. 2002. U.S. Environmental Protection Agency. Development Document for Final Effluent Limitations Guidelines and Standards for the Iron and Steel Manufacturing Point Source Category. Washington, DC. (April). EPA-821-R-02-004.