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

United States
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SECTION 1 BACKGROUND

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"). See the preamble for specific details related to the regulatory options considered and a description of the final rule. Where information described in this Supplemental Technical Development Document differs from what is described in the preamble, the preamble supersedes this document.

EPA conducted 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 (BA) transport water discharged from steam electric power plants. This document presents supporting information for final revisions to the 2015 rule, and supplements the 2015 TDD by summarizing 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), 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 BA transport water, and the derivation of the final effluent limitations.

In addition to this report, other supporting reports include:

- *Supplemental Environmental Assessment for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental EA), Document No. EPA-821-R-20-002. The Supplemental EA summarizes the potential environmental and human health impacts that are estimated to result from implementation of the revisions to the 2015 rule.
- *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA Report), Document No. EPA-821-R-20-003. The BCA Report summarizes the estimates of societal benefits and costs resulting from implementation of the revisions to the 2015 rule.
- *Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA), Document No. EPA-821-R-20-004. The RIA presents a profile of the steam electric power generating industry, a summary of estimated costs and impacts associated with

the regulatory options, and an assessment of the 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 EPA's Quality Policy and Information Quality Guidelines. 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

EPA is revising 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, EPA establishes effluent limitations guidelines and standards as summarized in the 2015 TDD.

1.2 Regulatory History of the Steam Electric Power Generating Point Source Category

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 steam electric 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: BA 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 (NPDES), 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 were 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 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, EPA responded to these petitions by postponing 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 BA transport water. The Fifth Circuit Court of Appeals heard the consolidated petitions for review of the 2015 rule and subsequently granted EPA's request to sever and hold in abeyance aspects of the litigation related to the FGD wastewater and BA 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 final rulemaking, the Fifth Circuit's decision of April 12, 2019, vacated the limitations as arbitrary and capricious under the APA, and unlawful under the CWA

In September 2017, EPA finalized a rule, using notice-and-comment procedures, postponing the earliest compliance dates for the new, more stringent BAT effluent limitations and PSES for FGD wastewater and BA transport water in the 2015 rule, from November 1, 2018, to November 1, 2020. EPA also withdrew its prior action, taken pursuant to Section 705 of the APA. Legal challenges to EPA's Section 705 Action, as well as to EPA's postponement of compliance deadlines following notice and an opportunity to comment, have since been dismissed.

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

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_2) 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, 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_2 emissions from existing coal-fired electric utility generating units consistent with EPA's role as defined in the CAA.

ACE establishes heat rate improvement (HRI), or efficiency improvement, as the best system of emissions reduction (BSER) for CO_2 from coal-fired electric utility generating units.[1] By employing a broad range of HRI technologies and techniques, electric utility generating units can more efficiently generate electricity with less carbon intensity.[2] 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, 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.[3] For each candidate technology, 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 analyses supporting the final rule use the most up-to-date version of IPM available, which includes an illustrative representation of the requirements of the final ACE rule. See the RIA for more detail on IPM and how it accounts for the final ACE rule.

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

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

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

[3] 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.

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 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.

In response to the D.C. Circuit Court rulings in *Utility Solid Waste Activities Group (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 were proposed in November 2019 (Part A) and in March 2020 (Part B). On July 29, 2020, EPA finalized the Part A amendments to the closure regulations for the disposal of CCRs. In particular, the final Part A rule includes:

- Establishing a new deadline of April 11, 2021, for all unlined surface impoundments and those surface impoundments that failed the location restriction for placement above the uppermost aquifer to stop receiving waste and begin closure or retrofit. EPA determined this date after evaluating the steps owners and operators need to take to cease receipt of waste and initiate closure and the time frames necessary for implementation.
- Establishing procedures for facilities to obtain additional time to develop alternate capacity to manage their wastestreams (both coal ash and non-coal ash) before they stop receiving waste and initiate closure of their coal ash surface impoundments.
- Changing the classification of compacted-soil-lined or clay-lined surface impoundments from “lined” to “unlined.”
- Revising the coal ash regulations to specify that all unlined surface impoundments are required to retrofit or close.
- 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, 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 continued to be an important consideration in the development of the 2019 proposal and this final ELG rule. In order to account for the final CCR Part A rule amendments in this final ELG rule, EPA modified its baseline costs and pollutant loads to estimate how the closure of unlined surfaced impoundments pursuant to the CCR Part A rule may impact the compliance cost and pollutant loading estimates of the ELG rule, see Section 3.3 for more details.

SECTION 2
DATA COLLECTION ACTIVITIES

EPA collected and evaluated information from various sources in developing the 2015 rule, as described in Section 3 of the 2015 TDD. As part of this final rule, 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 flue gas desulfurization (FGD) wastewater and bottom ash (BA) transport water as they relate to technical aspects of the final rule:

- Site visits and plant outreach (Section 2.1).
- Industry-submitted data (Section 2.3).
- Technology vendor data (Section 2.4).
- Other data sources (Section 2.5).
- Protection of confidential business information (Section 2.5.5).

2.1 SITE VISITS AND PLANT OUTREACH

After promulgating the 2015 rule, 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 BA transport water. Table 2-1 lists the site visits conducted following the 2015 rule. 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. EPA prioritized plants engaged in FGD wastewater treatment pilot studies or with updated FGD treatment or bottom ash handling systems. 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.

EPA revisited four power plants that were previously visited in support of the 2015 rule because these had recently conducted, or were currently conducting, FGD wastewater treatment pilot studies. 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, EPA also 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 Rule

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

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). See the 2020 Supplemental EA for a more detailed discussion on sources of bromides found in FGD wastewater and their impacts to downstream drinking water intakes.

Following the 2019 proposal, EPA conducted calls with the following:

- One of two coal-fired power plants operating a compact submerged conveyor (CSC) to transport bottom ash. The CSC system installed and operating as of winter 2019, was a retrofit to the bottom ash handling system. EPA discussed the selection of a CSC system, the plant's evaluation of the technology, an overview of the installation process, and operation and maintenance of the system. (ERG, 2020v).
- A plant operating technology for FGD wastewater treatment and bottom ash handling that could have complied with the 2019 proposed effluent limitations. The plant installed a thermal evaporation system to treat their FGD wastewater and a pneumatic ash extractor (PAX) dry bottom ash handling system (ERG, 2020q). EPA discussed the process of selecting, bidding, installing, and operating these systems. Both the FGD and bottom ash systems were updated to meet water-quality-based NPDES permit limitations for mercury, boron, thallium, manganese, and selenium.
- A plant operating a thermal FGD system and a remote mechanical drag system (rMDS) for bottom ash handling that could have met the 2019 proposed effluent limitations. EPA discussed the process of selecting, bidding, installing, and operating these systems. FGD treatment system upgrades resulted from new water-quality-based limitations on metals, while the bottom ash upgrade was driven by compliance with the Coal Combustion Residuals (CCR) Rule (ERG, 2020u).
- A plant planning to conduct a long-term pilot test of membrane filtration and other FGD treatment technologies. EPA discussed details of the planned pilot study (ERG, 2020x).
- An independent power producer with customers in the northeast and mid-Atlantic, that filed certifications with the Maryland Department of the Environment for three

plants to participate in the voluntary incentive program (VIP) established by the 2015 rule. EPA discussed the details of the compliance strategies at these facilities and how the proposed changes to the VIP may affect those plans (ERG, 2020o).

During these calls, EPA also discussed the impacts that the current COVID-19 pandemic was having on operations at these power plants. EPA asked plant personnel how new policies, ongoing construction, and planned outages might affect future compliance with the final rule.

2.2 Public Comments and Online Public Hearing

During the 60-day public comment period for the 2019 proposed rule (November 22, 2019, to January 21, 2020), EPA received more than 7,400 public comment submissions from private citizens, industry members, technology vendors, environmental groups, and trade associations. EPA also hosted an online public hearing on December 19, 2019, at which the public could voice comments on the proposed rule. The online hearing had 110 attendees, 32 of whom provided verbal comment on the proposed rule. Available documents from the public hearing include the presentation given by EPA and a transcript of the webinar (U.S. EPA 2019a, 2019b).

2.3 Industry-Submitted Data

EPA obtained information on steam electric power generating 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 2.3.1 and 2.3.2 summarize the industry-submitted data collected.

2.3.1 Clean Water Act Section 308 Industry Request for FGD Wastewater

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

- 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.

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. 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, 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, EPA conducted follow-up meetings and conference calls with industry representatives to discuss and clarify these data.

2.3.2 Voluntary Sampling Program for Bottom Ash Transport Water

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

2.4 TECHNOLOGY VENDOR DATA

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 BA transport water. EPA participated in multiple technical conferences and reviewed the papers presented for information relevant to the final rule.

To gather FGD wastewater treatment information for the cost analyses, EPA contacted companies that manufacture, distribute, or install various components of biological wastewater treatment, membrane filtration, or thermal evaporation systems. 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 operation and maintenance (O&M) costs.
- System energy requirements.
- Timeline.

To gather information on bottom ash handling systems, EPA 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 high recycle rate systems.[4]
- Equipment that can be reused as part of the conversion from wet to dry handling or in a high recycle rate system.
- Outage time estimated for the different types of ash handling systems.
- Maintenance estimated for each type of system.
- Estimated capital and operation and maintenance (O&M) costs.

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

2.5 OTHER DATA SOURCES

EPA obtained information on steam electric power generating 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), EPA's Office of Resource Conservation and Recovery (ORCR) within the Office of Land and Emergency Management, literature and internet searches, and environmental groups. Sections 2.5.1 through 2.5.5 summarize the data collected from these additional sources during reconsideration of the 2015 rule.

2.5.1 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. EPA met with UWAG to discuss approaches for managing discharges of FGD wastewater and BA 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. EPA reviewed 45 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, BA transport water characterization, bottom ash handling practices, and the effect of halogen additives on FGD wastewater.

[4] Throughout this report, 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 and compact submerged conveyor) still use water in a quench bath and, therefore, are not completely dry systems.

Table 2-2. EPRI Reports and Studies Reviewed by 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
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 SE08178A3
Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges	September 201	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

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

Title of Report/Study	Date Published	Document Control Number
Landfill Leachate Characterization, Management and Treatment Options	November 2017	DCN SE06959
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
Biological Treatment of Wastewater from a Once-Through Wet Flue Gas Desulfurization Process	January 2020	DCN SE08566
Evaluation of the Effectiveness of Enhanced Chemical Precipitation Treatment for Removal of Contaminants from Bottom Ash Purge from a Remote Mechanical Drag System	March 2020	DCN SE08671
Considerations for Treating Flue Gas Desulfurization Wastewater Using Membrane and Paste Encapsulation Technologies	November 2019	DCN SE08609
Field Evaluation of Prototype Selenium and Mercury Water Quality Monitors for Flue Gas Desulfurization Wastewater	November 2018	DCN SE08920
Field Evaluation of Commercially Available and Prototype Mercury and Selenium Monitors for Flue Gas Desulfurization Wastewater	March 2019	DCN SE08921
Water Quality Monitoring for FGD Wastewater and Ash Pond Water Treatment Process Control	October 2019	DCN SE08922

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

Title of Report/Study	Date Published	Document Control Number
Survey of Water Quality Monitors for Coal-Fired Power Plant Wastewater	December 2019	DCN SE08923
2014 Update on EPRI's Balance-of-Plant Effects Study of Bromine-Based Mercury Controls	December 2014	DCN SE08924
Halogen Addition of Hg Control and Related BOP Issues: 2016	November 2016	DCN SE08925
Mercury and Air Toxics Control	December 2017	DCN SE08926
Impacts of Bromide from Power Plants on Downstream Disinfection Byproduct Formation	November 2019	DCN SE08930

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. EPA met with ICAC to learn more about mercury air pollution control technologies for coal-fired EGUs, with a specific focus on the use of halogens and the impacts halogens may have on drinking water plants located downstream of power plants.

2.5.2 Department of Energy

EPA used information on steam electric power 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 2017, 2017a, 2018 and 2018a). 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. EPA also used data reported to DOE to estimate bromide loadings from FGD discharges, including fuel consumption by coal type and coal purchases by county and coal type.

2.5.3 Literature and Internet Searches

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. 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 high recycle rate ash handling systems. 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.

EPA also identified additional FGD wastewater treatment technologies that are being tested and installed. 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. EPA's evaluation of FGD treatment technologies is further discussed in the preamble.

2.5.4 Environmental Groups

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 limitations.

2.5.5 EPA Office of Resource Conservation and Recovery

The 2015 CCR rule established requirements for the safe disposal of CCRs from coal-fired steam electric power plants. The CCR rule requires owners or operators of CCR surface impoundments and landfills to record compliance with the rule's requirements and maintain a publicly available website of compliance information.

EPA used plant-specific information on CCR surface impoundments from EPA's ORCR to estimate potential impacts from the CCR Part A rule. In January 2020, EPA's ORCR provided the Office of Water with publicly available CCR compliance information for 533 surface impoundments, corresponding to 231 facilities, subject to the CCR Part A rule requirements (U.S. EPA, 2020b). EPA's assessment of the January 2020 data set and methodology for estimating impacts from the CCR Part A rule are described in Section 3.3.

2.6 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, 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, 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, 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.

SECTION 3
CURRENT STATE OF THE STEAM ELECTRIC POWER GENERATING INDUSTRY

As part of the final rule, EPA updated the industry profile, evaluated changes in wastewater management practices, and assessed impacts from other regulations affecting steam electric power plants since the completion of the 2015 rule analysis. Section 3.1 describes changes to the steam electric power plant population. Section 3.2 summarizes current information on discharges of flue gas desulfurization (FGD) wastewater and bottom ash (BA) 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 final 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.[5] Therefore, 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 electric generating units (EGUs) and updates to wet FGD systems, FGD wastewater treatment, and bottom ash handling systems at steam electric power plants.

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 EGUs.
- Retirement of coal-fired EGUs.[6]
- Fuel conversions of coal-fired EGUs 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.

[5] EPA accounted for all industry profile changes announced and verified as of August 2014 in the 2015 rule analyses.

[6] For the purposes of this analysis, EPA accounted for EGUs that will be indefinitely removed from service (i.e., idled or mothballed) as retirements. See the preamble for discussion of EPA's evaluation of coal-fired EGUs nearing end of life.

- Installation of, or conversion to, dry, closed-loop recycle, or high recycle rate wet-sluicing bottom ash handling system.[7]

EPA has identified 477 coal-fired EGUs at 231 plants with at least one significant change in operation taking place between August 2014 and December 31, 2028 (the date by which the final rule would be fully implemented). Table 3-1 presents the count of steam electric generating units and plants, broken out by type of operation change.

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

Change in Operation	Count [a]	
	Electric Generating Units [b]	Plants [c]
Commissioning of New Coal-Fired Electric Generating Unit (EGU) [d]	18	16
Retirement of Coal-Fired EGU	269	141
Fuel Conversion to Non-Coal Fuel Type [e]	58	34
Installation of Wet FGD System	10	5
Modification or Upgrade of FGD Wastewater Treatment System	56	20
Installation or Conversion to Dry, Closed-Loop Recycle, or High Recycle Rate Bottom Ash Handling System	96	48

Source: ERG, 2020a.

Note: EPA's analysis accounted for all changes in operation announced and verified by February 2020. Any changes in operation or planned modifications identified after February 2020 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 Final Rule" for additional information on plants identified with industry profile changes and EPA's sensitivity analysis (ERG, 2020d).

a – Counts are not additive because there may be multiple changes in operation at a single steam electric EGU 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 an EGU 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 using 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 EGUs at seven power plants, plus 11 coal-fired EGUs commissioned at nine new plants (i.e., plants not accounted for in the 2015 rule analyses).

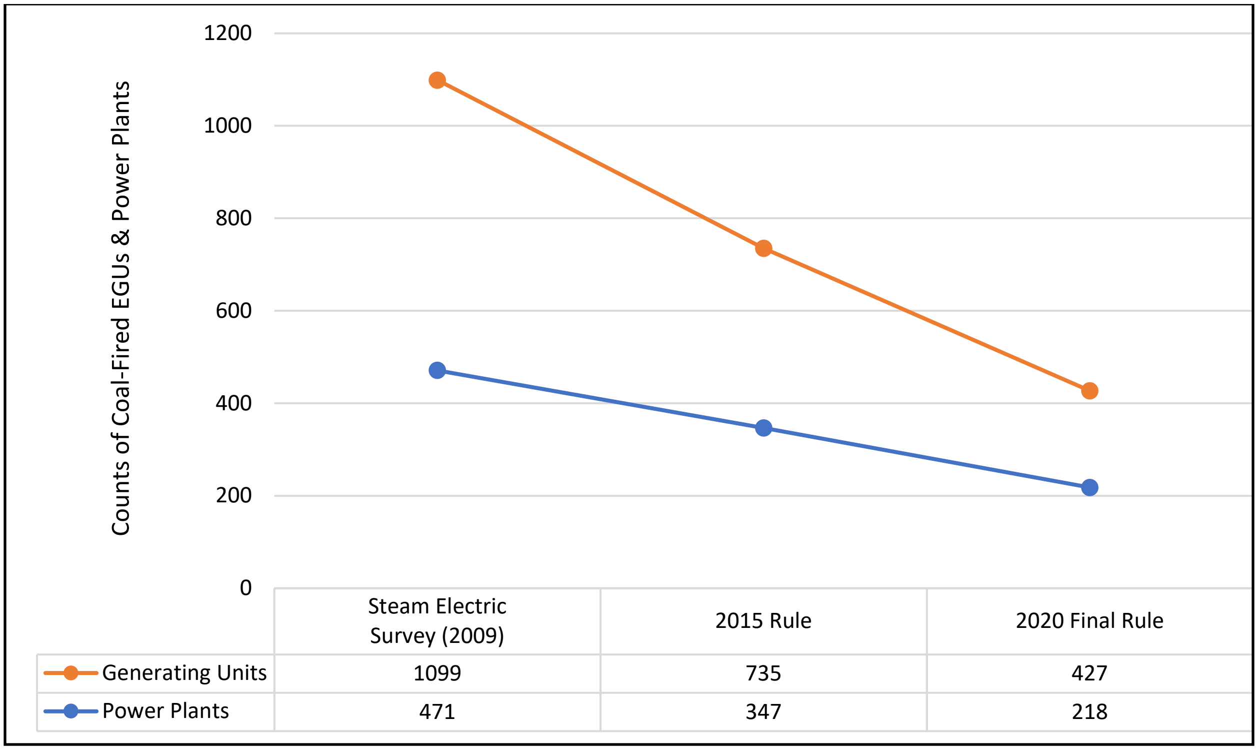
e – Includes 50 coal-fired EGUs at 28 plants converting to natural gas, one coal-fired EGU at a plant converting to hydrogen fuel, two coal-fired EGUs at two plants converting to biomass, and five coal-fired EGUs at three plants ceasing to burn coal (and whose announcement does not specify type of fuel conversion).

[7] 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, 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 most or all of the bottom ash transport water back to the bottom ash handling system, respectively.

EPA updated the industry profile to account for coal-fired EGUs subject to the steam electric power generating ELGs that began operation after the 2010 *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey). The Agency used information from two Energy Information Agency (EIA) data collection forms, Form EIA-860 (Annual Electric Generator Report) and Form EIA-923 (Power Plant Operations Report), for the calendar year 2018 to identify EGUs commissioned since 2009 (U.S. DOE, 2018a, 2018b). Those active coal-fired EGUs 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 had already been captured in the 2015 rule analyses). EPA added new EGUs 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 final rule. EPA collected information on unit operations and wastewater management practices for these EGUs 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, 2019c).

As shown in Table 3-1, the number of coal-fired EGUs 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. The population of coal-fired EGUs and plants decreased to 427 EGUs at 218 plants, 42 percent fewer generating units than the 2015 rule population.[8] Figure 3-1 illustrates the change in the number of operating coal-fired EGUs and plants since the Steam Electric Survey and 2015 rule. EPA identified 46 coal-fired EGUs at 27 power plants that are expected to retire or convert fuel types between December 31, 2023 (the date by which the 2015 rule would be fully implemented), and December 31, 2028 (the date by which the final rule will be fully implemented).

[8] The 2015 rule analyses accounted for industry profile changes to be completed before December 31, 2023 (the latest date that power plants were subject to the established BAT effluent limitations).



Source: ERG, 2020d.

Figure 3-1. Population of Coal-Fired Electric Generating Units (EGUs) and Plants

To meet air quality requirements, power plants use a variety of FGD systems to control sulfur dioxide (SO_2) emissions from flue gas generated in the plant's EGUs. For this final rule, EPA updated the profile to account for wet FGD systems on coal-fired EGUs 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. EPA collected information on FGD wastewater 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, EPA identified plants upgrading or planning to upgrade their bottom ash handling practices or FGD wastewater treatment systems. EPA collected information on bottom ash handling conversions and FGD wastewater treatment upgrades made at each plant and corresponding EGUs, and incorporated changes that would be completed by December 31, 2028, into the industry profile and corresponding technical analyses.

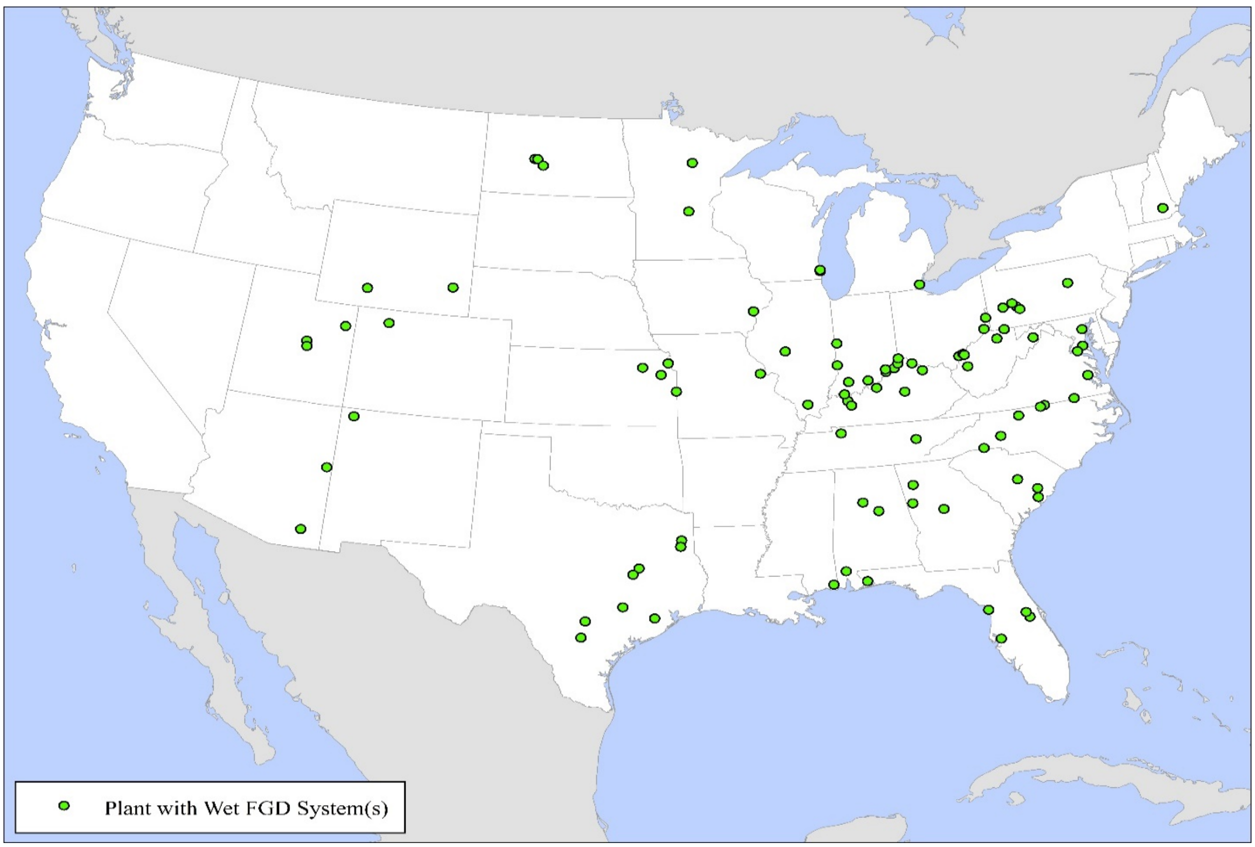
Section 5 and Section 6 describe how EPA accounted for the changes in operation identified in Table 3-1 in estimating compliance costs, pollutant loadings, and pollutant removals for this final rule. Additional information regarding specific coal-fired EGUs and plants identified as implementing each 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 Final Rule" (ERG, 2020d).

3.2 CURRENT INFORMATION ON EVALUATED WASTESTREAMS

This section summarizes current information on the generation, characteristics, and discharge of FGD wastewater and BA transport water that EPA collected for the final rule.

3.2.1 FGD Wastewater

As discussed in Section 3.1, EPA updated the industry profile and corresponding analyses to reflect coal-fired EGUs that will retire, convert fuels, or upgrade FGD wastewater treatment prior to December 31, 2028. EPA also updated the industry profile to reflect wet FGD systems that began operating after the Steam Electric Survey. Of the 427 coal-fired generating units at 218 coal-fired power plants in the updated profile, 210 generating units at 91 plants are serviced by a wet FGD system. EPA estimates EGUs with wet FGD systems have a total wet-scrubbed capacity of 120,000 MW, representing 62 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 EGU.



Sources: ERG, 2015 and 2020a.

Note: Steam electric power plants shown operate a wet FGD system on at least one EGU as of February 2020, excluding EGUs 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 EGUs burning bituminous coal. Often, plants also operate selective catalytic reduction (SCR) systems on these EGUs to control nitrogen oxide (NO_x) emissions.

Following promulgation of the 2015 rule, EPA collected new information on air pollution control practices at steam electric power plants that may impact characteristics of FGD wastewater. Specifically, EPA found that steam electric power plants may add halogens (e.g., bromine, chlorine, or iodine) to reduce mercury air emissions. While all coal contains at least some naturally-occurring halogens, steam electric power plant operators can augment coal halogen concentrations at various points in the plant operations to enhance mercury oxidation for mercury capture (e.g., directly injecting halogen during combustion; mixing bromide with coal to produce refined coal; and using brominated activated carbon to control air emissions). Halogens in flue gas at steam electric power plants are captured by wet FGD systems and discharged in FGD wastewater. See Section 6 for a more detailed discussion on halogens.

Steam electric power plants have conducted on-site testing and/or installed a variety of technologies to treat FGD wastewater, including chemical precipitation, constructed wetlands, zero-valent iron cementation, adsorption, ion exchange, and electrocoagulation. low residence time reduction (LRTR) biological treatment, high residence time reduction (HRTR) biological treatment, advanced membrane filtration, and thermal evaporative systems. EPA has identified that approximately 14 percent of steam electric power plants with wet scrubbers have technologies in place able to meet the final BAT effluent limitations for FGD wastewater, including LRTR, HRTR, and thermal evaporation systems. As described in Section VII of the preamble, a further 35 percent of all steam electric power plants with wet scrubbers use FGD wastewater management approaches that eliminate the discharge of FGD wastewater altogether; however none of these technologies are available nationwide and thus do not form the basis for the final BAT limitations. See Section 4 for more details on these treatment technologies employed by some 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 Electric 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)
56	135	31.9	0.570	11,600	208

Source: ERG, 2020h.

MGY = million gallons per year.

Note: Counts and flow rates do not include EGUs that will retire or convert fuels by December 31, 2028 and wet FGD systems that began operating after the Steam Electric Survey are excluded from the table.

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 BA transport water from impoundments, dewatering bins, or other handling systems back to the wet-sluicing system; however, most BA transport water was discharged to surface water. At the time of the Steam Electric Survey, less than 40 percent of EGUs 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 EGUs operated or planned to convert to dry, closed-loop recycle, or high recycle rate bottom ash handling systems.

As discussed in Section 3.1, EPA updated the industry profile and corresponding analyses to estimate the number of coal-fired EGUs 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 BA transport water. In addition, based on data from the Steam Electric Survey, EGUs commissioned after 2009 are likely to operate dry or closed-loop recycle bottom ash handling systems.[9] Further, the number of coal-fired EGUs 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 EGUs operating wet sluicing, closed-loop recycle, high recycle rate, and/or dry bottom ash handling systems. EPA estimates that today more than 75 percent of EGUs operate either dry, closed-loop recycle, or high recycle rate bottom ash handling systems.[10] Figure 3-3 illustrates the geographic distribution of plants operating the systems noted in Table 3-3.

[9] 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 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.

[10] Counts presented in this paragraph and Table 3-3 do not reflect bottom ash handling conversions expected as a result of the CCR Part A rule.

Table 3-3. Bottom Ash Handling Systems for Coal-Fired Electric Generating Units (EGUs)

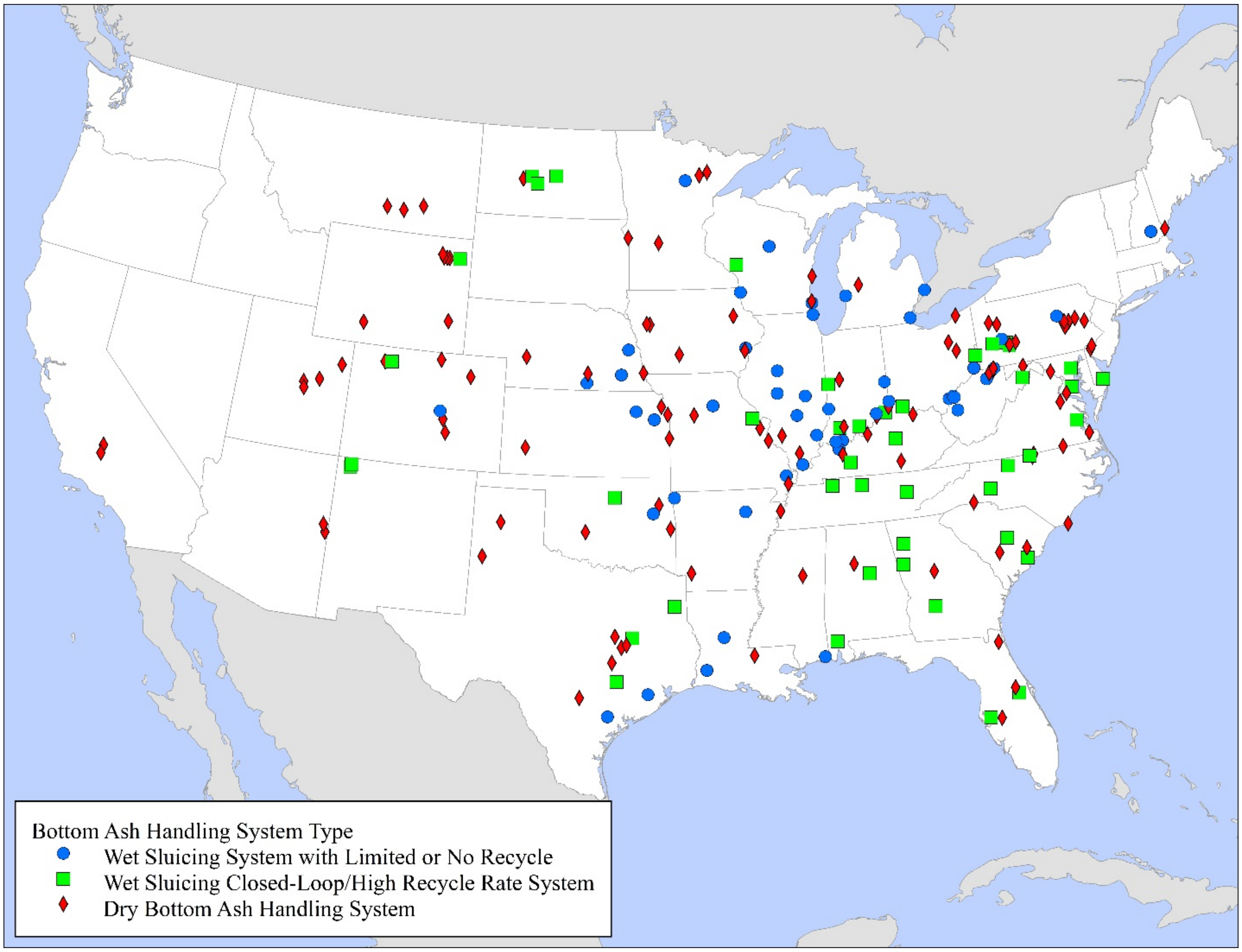
Bottom Ash Handling System	Number of Plants	Number of EGUs	Nameplate Capacity (MW)
Wet Sluicing System with Limited or No Recycle	49	106	51,700
Wet Sluicing Closed-Loop/High Recycle Rate System	45	108	56,800
Dry Bottom Ash Handling System [b]	132	213	85,400
Total	**218** [a]	**427**	**194,000**

Source: ERG, 2020d.

Note: Counts and capacities for coal-fired EGU retirements, fuel conversions, and bottom ash handling conversions that will have been completed by December 31, 2028 are excluded from the table. Values do not reflect additional bottom ash handling system conversions that plants will implement to comply with the CCR Part A 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 EPA in the Steam Electric Survey and publicly available information since 2009. Where data were available, EPA tracked the specific types of bottom ash handling conversions, such as mechanical drag systems (MDS) and remote mechanical drag systems (rMDS). However, EPA identified 31 EGUs, corresponding to 13,100 MW at 17 plants, where the data confirmed that the plant was not discharging BA transport water, but did not confirm the specific type of non-discharging system.



Sources: ERG, 2015 and 2020a.

Note: Excludes power plants that will retire or convert fuels for all coal-fired EGUs 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 EGUs	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)
49	106	114	2.33	41,600	849

Source: ERG, 2020a.

Note: Counts and capacities for retirements, fuel conversions, or bottom ash handling conversions at coal-fired EGUs that will be complete by December 31, 2028 are excluded from the table. Values do not reflect bottom ash handling system conversions EPA expects plants to implement to comply with the CCR Part A 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, EPA assessed and incorporated impacts from the Clean Power Plan (CPP) and CCR rule into the supporting analyses. Specifically, in the 2015 TDD, 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, EPA proposed to repeal the CPP and the regulation was indefinitely stayed by the U.S. Supreme Court. Due to this development, EPA's analyses for baseline and the regulatory options do not consider expected profile changes associated with the CPP. EPA finalized the Affordable Clean Energy (ACE) rule on June 19, 2019. The ACE rule replaces the 2015 CPP rule and establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. Any retirements expected from the ACE rule are already factored into the industry profile and reflected in EPA's costs and pollutant loadings for the ELG final rule.

EPA has continued to account for industry profile changes associated with the CCR rule. 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, 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.

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

For the 2015 rule, 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. 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 EPA used the classifications to adjust compliance costs, pollutant loadings/removals, and other analyses for each wastestream for the 2015 rule.

As discussed in Section 1.3, EPA finalized the CCR Part A rule on July 29, 2020, setting a deadline of April 11, 2021 for all unlined surface impoundments and those surface impoundments that failed the location restriction for placement above the uppermost aquifer to stop receiving waste and begin closure. The CCR Part B rule was proposed in March and has yet to be finalized. For this final rule, EPA developed a methodology to use CCR surface impoundment liner data to estimate operational changes at each coal-fired power plant under the CCR Part A rule.

Using the publicly available data described in Section 2.5.5, EPA evaluated available liner designation information for all plants that may be affected by the CCR Part A rule and the final rule. Based on the CCR Part A rule, plants with unlined or clay-lined CCR surface impoundments will be required to change operation or install a new CCR compliant impoundment. Where all active CCR surface impoundments are unlined or clay-lined, EPA predicts that a plant will install tank-based FGD wastewater treatment or tank-based bottom ash handling under the CCR Part A rule.[11] For plants with at least one CCR surface impoundment not impacted by the CCR Part A rule (i.e., not identified as unlined or clay-lined,[12] or where no data were available in the ORCR data set), EPA conservatively assumed the CCR Part A rule would have little to no impact to a plant's existing FGD wastewater treatment or bottom ash handling systems; thus, for these plants, the estimated compliance cost and pollutant loads remain unchanged for the ELG final rule.

Using this methodology, EPA estimates that 32 plants would convert to mechanical drag or remote mechanical drag bottom ash handling systems because of the CCR Part A rule, and as a result would not incur BA transport water compliance costs attributable to the final rule.[13] In

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[11] For plants with at least one surface impoundment in the ORCR data set, EPA's Office of Water assumed the listed CCR surface impoundment(s) represent all impoundments receiving FGD wastewater and/or bottom ash transport water at the plant.

[12] The ORCR data set includes 34 active CCR surface impoundments without liner designations. For these CCR surface impoundments, EPA's Office of Water did not assume they were unlined or clay-lined; therefore, EPA may be underestimating the number of plants that will install tank-based FGD wastewater treatment or bottom ash handling in response to the CCR Part A rule.

[13] Plants that install rMDS to comply with the CCR Part A 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

addition, EPA estimates seven plants would modify their FGD wastewater treatment because of the CCR Part A rule and, as a result, their costs to comply with the final rule would be reduced. Section 5 and Section 6 describe how EPA accounted for CCR Part A rule impacts in estimating compliance costs, pollutant loadings, and pollutant removals for the final rule. EPA also conducted a sensitivity analysis to estimate the combined impact of CCR Part B rule and the final rule. For those plants projected to be allowed to continue operating CCR impoundments under the CCR Part B rule, EPA assessed how continuing to operate these could change the ELG final rule costs, see the memorandum titled "Sensitivity Analysis for Estimating the Impacts of the CCR Part B Rule" for these estimates (ICF, 2020).

ash, which is wet as it is removed from the rMDS. As appropriate, EPA will update the compliance cost estimates for these plants in future analyses.

SECTION 4
TREATMENT TECHNOLOGIES AND WASTEWATER MANAGEMENT PRACTICES

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 (BA) transport water. 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 BA transport water since the 2015 rule.

4.1 FGD WASTEWATER TREATMENT TECHNOLOGIES

In promulgating the 2015 rule, 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 (best available technology economically achievable) 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, an adiabatic evaporator, or the falling-film evaporator design, which was used as the basis for the NSPS limitations and the BAT Voluntary Incentive Program (VIP) in the 2015 rule. See the 2015 TDD for a description of thermal treatment technologies and other zero discharge technologies.

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 domestic power plants or had been tested or installed at foreign power plants. This section provides a summary of the treatment technologies evaluated as part of the final rule, including:

- Biological treatment.
- Zero-valent iron (ZVI).
- Membrane filtration.
- Thermal treatment.
- Encapsulation.
- 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 biological oxygen demand (BOD).

These biological treatment processes are typically operated downstream of a chemical precipitation system or a solids removal system (e.g., clarifier or 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, as it has been applied at 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. Plants usually employ multiple bioreactors to provide the necessary residence time to achieve the specified removals. The HRTR biological technology was the basis for effluent limitations established by the 2015 rule.

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 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. 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. Several 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 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 similar 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 allows for use of 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 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, it 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. EPA identified 12 pilot studies of the FBR technology for selenium removal in mining, refining/petrochemical, and steam electric industries. Three of these pilot studies 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.[14] 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.

EPA identified two full-scale installations of the ZVI technology for selenium removal in mining wastewater and seven completed pilot-scale studies of ZVI used for FGD wastewater treatment.[15, 16] At least four additional pilot-scale studies for FGD wastewater treatment were in the planning stage at plants in the eastern United States, as of 2016. The data in the record from a subset of these pilot tests indicate 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 low residence time reduction (CP+LRTR), and chemical precipitation followed by high residence time reduction (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

[14] FGD purge with nitrate/nitrite concentrations at or above 100 mg/L typically require additional denitrification before ZVI treatment.

[15] EPA has limited data on the performance and configuration of the two full-scale ZVI systems treating mining wastewater (Butler, 2010). At least one of the systems includes ZVI in combination with a reverse osmosis membrane system to target selenium removal.

[16] In addition to the seven FGD pilots of ZVI, EPA has also observed ZVI technology in treating ash transport water during impoundment dewatering at a plant. 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 train has been suggested for FGD wastewater: chemical precipitation followed by reverse osmosis membrane filtration, with the membrane reject stream 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).

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 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, microfiltration). 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 encapsulation (See Section 4.1.5), in a commercial injection well, or another process, such as thermal system treatment (see Section 4.1.4).

EPA identified two full-scale domestic installations of reverse osmosis and one in South Africa for selenium or nitrate removal in the mining industry, and five domestic pilot studies in the petroleum refining and agriculture industries. EPA further identified four full-scale installations of membrane filtration in the coal-to-chemical industry in China and the textile industry in

India.[17] In the steam electric industry, EPA identified 17 pilot-scale studies of nanofiltration and reverse osmosis used for FGD wastewater treatment world-wide (ERG, 2020af) and 12 full-scale installations in China, South Korea, and Finland (ERG, 2020aa; Beijing Jingneng Power, 2017; Nanostone, 2019; Lenntech, 2020; and Broglio, 2019).[18] Some of the full-scale systems employ pretreatment and a combination of RO and forward osmosis. Others operate pretreatment followed by nanofiltration and RO. At least one plant uses thermal treatment to produce a crystallized salt from the brine which is sold for industrial use. EPA is also aware of one U.S. facility that is conducting a long-term pilot to test a membrane filtration system for the treatment of FGD wastewater (ERG, 2020x). Data from this pilot are not available.

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 byproduct that can be disposed of in a landfill. As described in the 2015 TDD, three U.S. plants have installed brine concentrator systems for FGD treatment and at least four coal-fired power plants in Italy also operate this type of system for FGD wastewater. Since proposal, EPA has identified one additional full-scale installation of thermal treatment for FGD wastewater at a U.S. plant (ERG, 2020d). As described in Section 4.1.3, in addition to full-scale thermal treatment alone, EPA identified coal-fired steam electric power plants in China that have installed brine concentrators followed by crystallizers following membrane filtration to treat FGD wastewater. 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 final rule development, 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 by 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

[17] EPA has limited data on the performance and configuration of the two full-scale membrane systems treating mining wastewater and the pilot-scale systems in other industries (Wolkersdorfer, 2015; U.S. EPA, 2014; CH2M Hill, 2010; ERG, 2020aa; ERG, 2019c). These systems may include a variety of membrane systems including nanofiltration, microfiltration, and RO systems.

[18] EPA has limited details on these full-scale membrane systems. Some references include only plant name or location. For this reason, some references may be describing the same installation, and EPA does not have enough information to determine where this may be the case.

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 encapsulated, 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 steam electric 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 <u>Encapsulation</u>

Encapsulation is another technology option that may prevent FGD wastewater discharge. Encapsulation is the process by which temperature and chemical reactions are used to bond materials together. This process can also be referred to as fixation or solidification. 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

EPA also identified several emerging technologies for FGD wastewater treatment. 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 ($CaSO_4$), solidified, or treated using a crystallizer. This system has been bench-scale tested using FGD wastewater in 2017 and pilot-scale tested for 60 days in the spring of 2018 (ERG, 2020ab).

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 crystalize 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, EPA reviewed bottom ash handling systems designed to minimize or eliminate the discharge of BA transport water that are operated by coal-fired steam electric power plants or marketed by bottom ash handling vendors. As part of the 2015 rule, EPA determined that almost 60 percent of the coal-fired power plants in the industry operate wet-sluicing systems on one or more of their coal-fired EGUs. As described in Section 3, many plants have installed, or are installing, bottom ash handling systems that minimize or eliminate the discharge of BA transport water. Specifically, EPA now estimates that just 22 percent of coal-fired steam electric power plants in the industry (projected to be operating beyond 2028) operate wet sluicing systems (see the 2015 TDD for more details on wet sluicing systems). The bottom ash handling technologies evaluated by EPA are listed below:

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

4.2.1 Mechanical Drag System

A mechanical drag system collects bottom ash from the bottom of the EGU 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 EGU and seals the EGU gases. The drag system uses a parallel pair of chains attached by 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. The chains then move 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 EGU 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 EGU 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 BA transport water because the transport mechanism is the drag chain, not the water (see 40 CFR 423.11(p)).[19]

[19] 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,

This system may not be suitable for all EGU configurations and may be difficult to install in situations where there is limited space below the EGU.[20] These systems are not able to combine and collect bottom ash from multiple EGUs and most installations require a straight exit from the EGU 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-sluicing systems at the bottom of the EGU. However, instead of sluicing the bottom ash directly to an impoundment, the plant pumps the BA 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 EGU, 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 EGU. 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 BA 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 BA transport 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 EGU. 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 mechanical drag systems, 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 EGU, making the EGU 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

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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.

[20] In comments on the 2013 proposed ELG, three plants reported space constraints below the boiler such that a mechanical drag system could not be installed.

headroom limitations and a wide range of steam electric EGU 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 EGU 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 EGU. 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 EGU efficiency. These systems are also less complicated to retrofit because there are fewer structural limitations (e.g., headspace requirements below the EGU) and the systems can be installed to collect bottom ash from multiple EGUs and send it to one intermediate storage location.

4.2.5 Compact Submerged Conveyor

Compact submerged conveyors (CSCs), also referred to as submerged grind conveyors, collect bottom ash from the bottom of the EGU. 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 EGU, 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 fully-enclosed bottom carry chain and flight conveyor system. Similar to a mechanical drag system, except for the fully-enclosed bottom carry design, a drag chain continuously carries and dewaters bottom ash up an incline, away from the EGU. Because the transport mechanism is a conveyor instead of water, CSCs do not generate BA transport water.[21] The dewatered bottom ash is transferred to one or more additional conveyors, which transports it to a bottom ash silo or bunker where the bottom ash is collected in a truck and transported to its final destination. CSCs use additional conveyors to avoid existing structures such as pillars and coal pulverizers while conveying bottom ash out of the EGU house. This makes it possible to install CSCs in some plants where physical constraints prevent installation of mechanical drag systems; however, physical constraints would similarly prevent CSC installation at other plants. CSCs can also use smaller chains and are narrower and shorter than mechanical drag systems, features that potentially allow them to fit in locations where there is insufficient space to install the larger mechanical drag system conveyors.

The systems can be isolated from the hopper using the existing transfer enclosures to perform maintenance while the EGU remains on line (made possible by the bottom ash storage capacity of the hopper). It is also possible for some plants to install parallel conveyors for redundancy (ERG, 2020t, 2020v, 2020ac, and 2020ad).

[21] Similar to the mechanical drag system, the CSC system is considered a dry handling technology because it does not use water as the transport mechanism.

For plants that are able to repurpose their wet sluicing equipment (hoppers, slag tanks, and/or clinker grinders, etc.), the capital costs of converting to CSC systems are typically lower, and installation and outage times are shorter compared to other under-the-EGU bottom ash handling systems. However, because a CSC serves just one EGU, the more EGUs a plant has, the less economical this technology becomes.

EPA is aware of two plants that have installed and are operating this type of bottom ash handling system in the United States. EPA is also aware of at least three more plants in the U.S. that are in the process of installing CSC systems and expected to begin operating in early 2021. EPA understands that these facilities do not have vertical space constraints under the EGUs.

SECTION 5
ENGINEERING COSTS

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 considered for discharges of flue gas desulfurization (FGD) wastewater and BA 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. Because the 2015 rule was codified in 40 CFR 423, the costs associated with the regulatory options for this final rule 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, 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 BA 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, EPA estimated baseline costs of installing the technologies selected as the BAT/PSES basis of the 2015 rule (i.e., chemical precipitation followed by high residence time reduction (CP+HRTR) for FGD wastewater; dry or high recycle rate 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 final rule for FGD wastewater and BA transport water, relative to the conditions currently present or planned at each plant. For those plants where upgrades would be needed, 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 BA 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 was 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 EPA used to estimate costs to achieve the final 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 BA transport water, 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 final effluent limitations guidelines and standards

(ELGs), and estimated the incremental cost or savings to meet each of the regulatory options considered for the final 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 final rule, EPA based its calculations on plants implementing these technologies to estimate incremental compliance costs incurred by the industry. EPA summed plant-specific costs to represent industry-wide compliance costs for each regulatory option considered for the final rule.

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), public comments on the proposed rule, site visits prior to the 2019 proposal, 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).

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. EPA based its estimate of service life of equipment that may be installed for FGD wastewater or BA transport water on a review of reported performance characteristics of compliance technology components. From this review, 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 Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more information on EPA's economic impact analyses (U.S. EPA, 2020a).

5.2 FGD WASTEWATER

EPA developed methodologies to estimate costs to install and operate the following technologies: chemical precipitation, CP+LRTR, CP+HRTR, membrane filtration, and thermal treatment.[22] Chemical precipitation is included as pretreatment for more advanced treatment technologies including LRTR, HRTR, membrane filtration, and thermal treatment, and as stand-alone treatment for some subcategories. 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), EPA included costs 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), 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.

For CP+HRTR (Section 5.2.4), the same technology basis as the 2015 rule BAT, 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.

[22] EPA estimated compliance costs for thermal treatment; however, EPA did not use that estimate as a basis for an FGD technology option for the final rule. See the "Flue Gas Desulfurization Thermal Evaporation Cost Methodology" for more information (ERG, 2020ae).

- 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), EPA included all the costs described above for the chemical precipitation system (as pretreatment) and included costs for the following:

- Treatment equipment (membrane filtration, reverse osmosis, and storage tanks).
- Concentrate management.
- Transportation and disposal of solids or concentrate.[23]

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, 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, 2020g). To establish the input values, 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, 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 the final rule, EPA updated the input values using additional information gathered from industry, public comments on the proposed rule, and information available from the Department of Energy (see Section 2). EPA developed a list of EGUs 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 EGUs that, since the 2015 rule, have retired or converted to a fuel other than coal. EPA also identified EGUs that have announced plans to retire or convert their fuel source between December 31, 2023 and December 31, 2028. This section describes the updates to cost inputs from the 2015 rule.

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

[23] EPA evaluated costs for three different methods of concentrate management. EPA evaluated costs associated with (1) encapsulation of the brine (or membrane reject) and transporting the solidified material to a landfill; (2) disposing of the brine via a commercial deepwell injection site; and (3) using a crystallizer to treat the brine and transport the resulting solid material to a landfill.

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. 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 EGUs, EPA calculated the non-optimized FGD purge flow rates using the same methodology that was used for the 2015 rule (ERG, 2020g). For those plants where one or more wet-scrubbed EGUs have been retired or converted to a non-coal fuel source (or have plans to do so by 2023), EPA updated FGD purge flow rates, taking into account that FGD wastewater would no longer be produced by the retired/converted EGUs.

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, 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. 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 EGUs serviced by a wet FGD system (in tons per year). Data from 2018 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 EGU: 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, 2020g).

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.

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, 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

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, EPA recognized that flow optimization was a viable approach for plants of all sizes; however, at that time, 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 final rule incorporate flow optimization for all wet-scrubbed plants where FGD system metallurgy can accommodate it.

In the cost analyses, 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, 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). 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, 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, EPA assumed that further flow optimization was not practical and the resulting optimized FGD flow rate is equal to the FGD purge flow. 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.

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.[24]

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.[25] 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.

[24] 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.

[25] 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, EPA set the optimized FGD flow equal to the FGD purge flow.

To estimate O&M costs, EPA used optimized FGD flow rates, recognizing that well-operated plants would take steps to optimize the volume of water to be treated and normalize the flow where possible, which will allow for more realistic annual cost estimates. 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

EPA identified data on each plant's current level of treatment for its FGD wastewater (ERG, 2020n). For plants that are already treating the FGD wastewater using some form of chemical precipitation, biological treatment, or evaporation treatment, EPA identified which specific treatment system components would still be needed to comply with the final 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 final rule.

Landfill Data

Like the 2015 rule, 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. 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 Part A Decision Data

As discussed in Section 3.3, EPA updated the FGD population for changes in plant operations as a result of the CCR Part A rule. The CCR Part A rule sets requirements for managing impoundments and landfills containing CCRs. Based on the CCR Part A rule requirements, EPA expects that all plants with unlined or clay-lined impoundments will alter how they operate their current CCR impoundments by either rerouting CCR waste, installing new CCR-compliant impoundments, or installing tank-based treatment. EPA developed a methodology to use EPA's impoundment liner data , described in Section 3.3, to predict operational changes at each coal-fired power plant under the CCR Part A rule. EPA identified plants with unlined or clay-lined CCR surface impoundments. Where all CCR surface impoundments are impacted by the CCR Part A rule, EPA assumed that the plant would install tank-based treatment. For FGD wastewater, this tank-based treatment is assumed to be equivalent to the chemical precipitation system described in Section 5.2.2. See Table 5-1 for details on how plants installing tank-based treatment under the CCR Part A rule were reflected in FGD wastewater cost and loadings estimates.

Table 5-1. ELG FGD Changes Accounting for CCR Part A Rule

CCR Part A Rule Decision	ELG Technology Basis Assumptions	Effect on ELG Compliance Costs	Effect on ELG Pollutant Loadings
All CCR surface impoundments expected to close or retrofit.	Plant installs BAT chemical precipitation system, getting full treatment-in-place credit.	Chemical precipitation treatment-in-place. For baseline, plants incur the following capital and O&M costs: Mercury analyzer Compliance monitoring All biological treatment system costs (including transportation/disposal)	Chemical precipitation treatment-in-place.
At least one CCR surface impoundment is not expected to close or retrofit.	No change.	No change.	No change.
No data.	No change.	No change.	No change.

EPA identified 30 plants discharging FGD wastewater operating all unlined or clay-lined CCR surface impoundments. Of these, 23 plants already operate chemical precipitation or more advanced FGD wastewater treatment (e.g., biological treatment or thermal systems). EPA expects the remaining seven plants will install a chemical precipitation system under the CCR Part A rule.

5.2.2 Cost Methodology for Chemical Precipitation

As described in the preamble, costs for chemical precipitation as a stand-alone treatment technology were estimated for a specific subcategory. Costs for chemical precipitation were also estimated as a pretreatment component for the VIP option. 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.
- Polymer addition and clarification to remove precipitants and other suspended solids.
- Acid addition for pH neutralization.
- Sand filtration for additional removal of suspended solids.

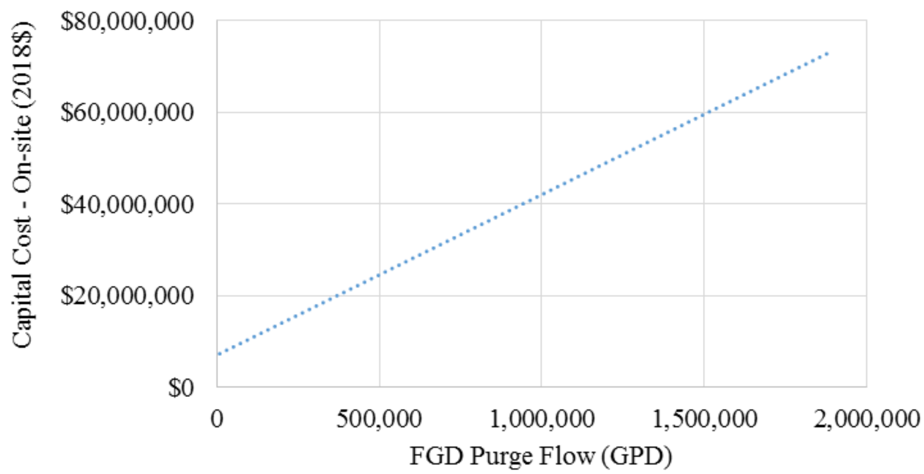
EPA used data from the 2015 rule to develop cost curves representing the capital and O&M costs for the chemical precipitation treatment system. The cost curves presented below include the following components:

- 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. 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

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.[26] Because costs are affected by the solids disposal location (i.e., on-site landfill or off-site transportation and disposal), 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, 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.



Chemical Precipitation Capital Cost with On-site Transport/Disposal (2018$) = 34.96 × FGD Purge Flow + 7,042,075

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

[26] EPA adjusted the 2015 rule original cost data basis from 2010 to 2018 dollars using RS Means Historical Cost Indexes.

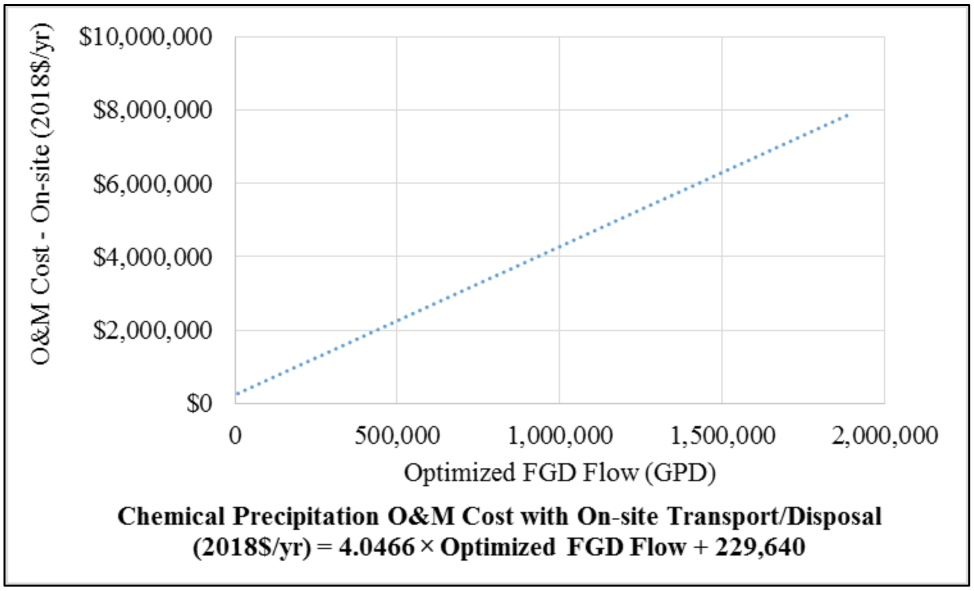


Figure 5-2. Chemical Precipitation O&M Cost Curve – On-site Transport/Disposal

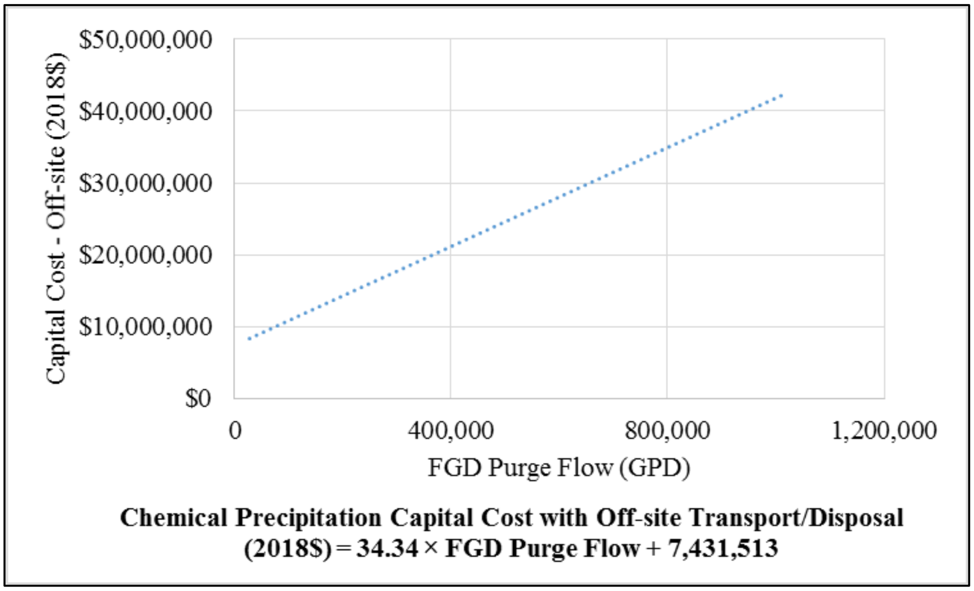


Figure 5-3. Chemical Precipitation Capital Cost Curve – Off-site Transport/Disposal

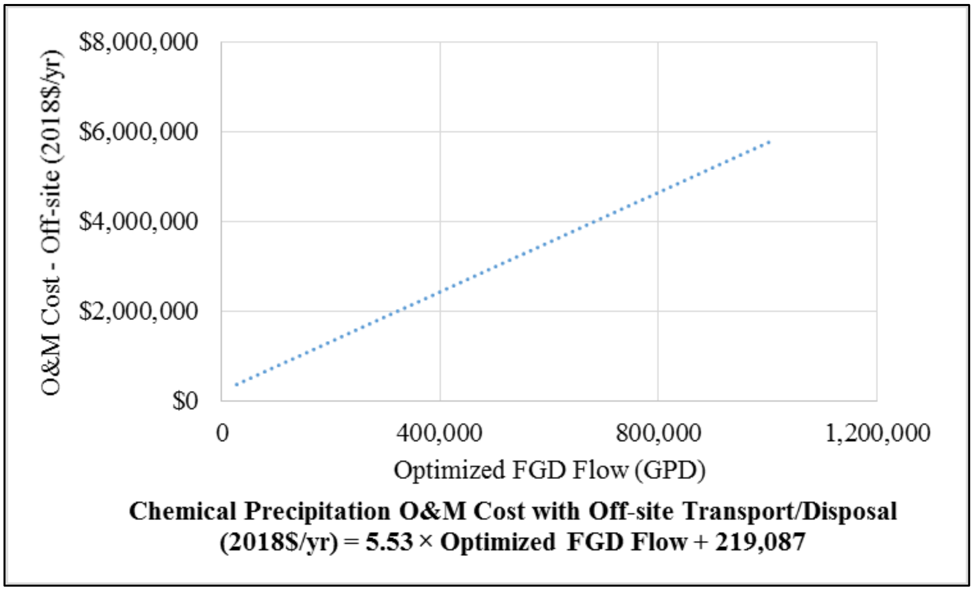


Figure 5-4. Chemical Precipitation O&M Cost Curve – Off-site Transport/Disposal

Recurring Costs

EPA's cost analyses include additional costs for the chemical precipitation system that would be incurred periodically after installation but less frequently than annually. 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. 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, 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 the final rule. Depending on the capital upgrades needed or additional O&M costs that would be incurred, 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, 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, 2020f). 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), 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. 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 Existing Treatment in Place

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

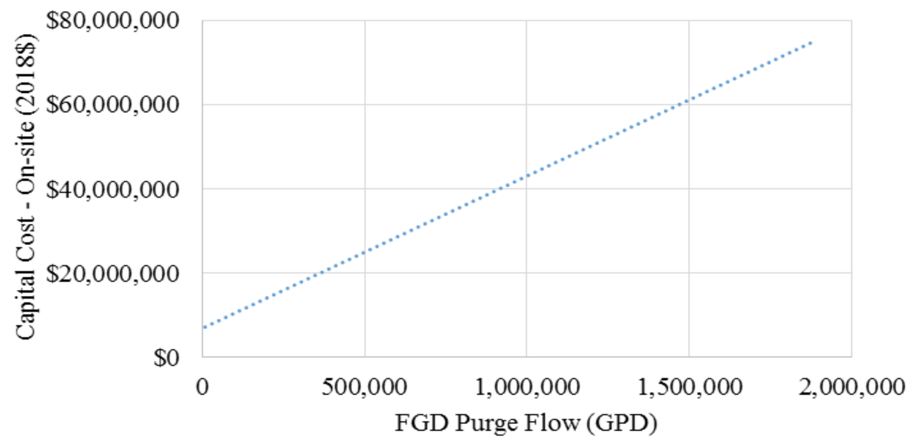
5.2.3 <u>Cost Methodology for Chemical Precipitation followed by LRTR (CP+LRTR)</u>

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

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.[27] 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, 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.



CP Pretreatment Capital Cost with On-site Transport/Disposal (2018$) = 36.17 × FGD Purge Flow + 6,909,668

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

[27] These costs differ slightly from those presented in Section 5.2.2 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.

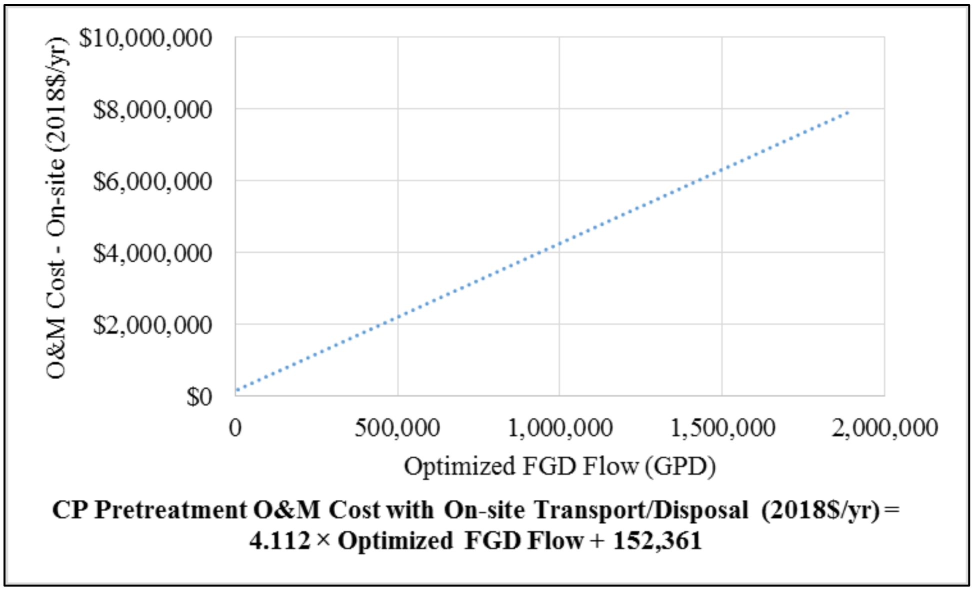


Figure 5-6. CP Pretreatment O&M Cost Curve – On-site Transport/Disposal

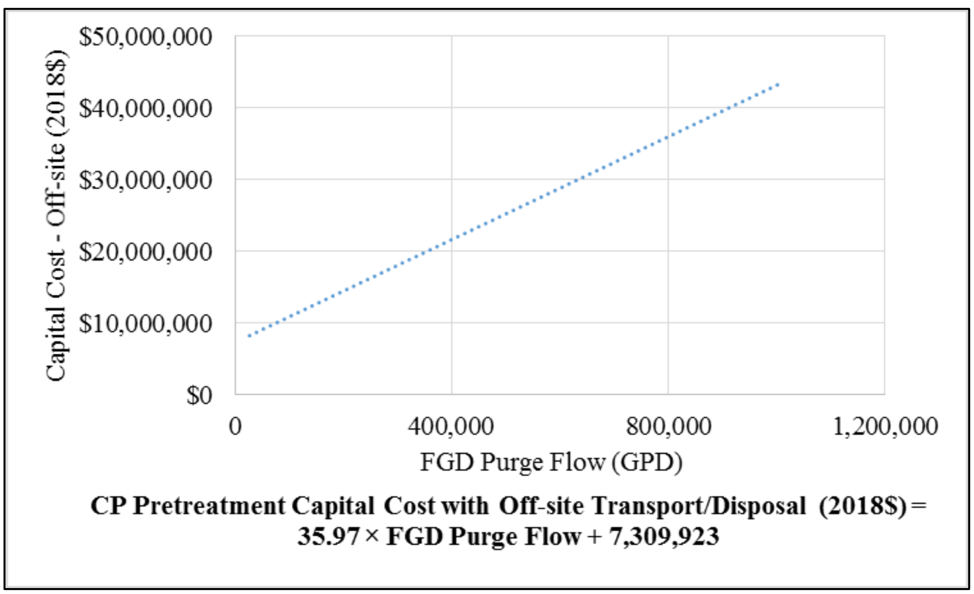


Figure 5-7. CP Pretreatment Capital Cost Curve – Off-site Transport/Disposal

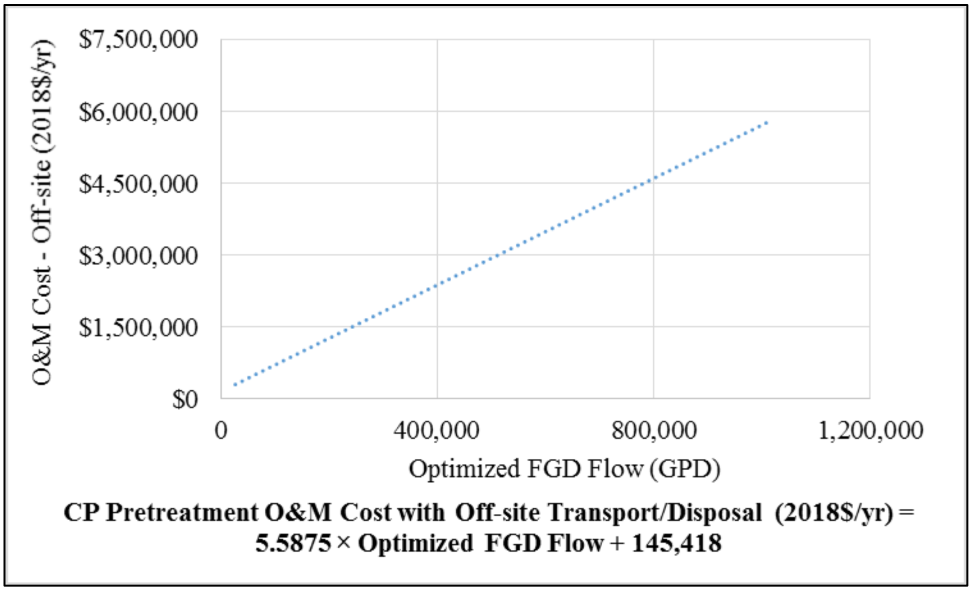


Figure 5-8. CP Pretreatment O&M Cost Curve – Off-site Transport/Disposal

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, 2020i). 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). 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, 2020i) demonstrated nitrate/nitrite concentrations at or above 50 mg/L in FGD purge.

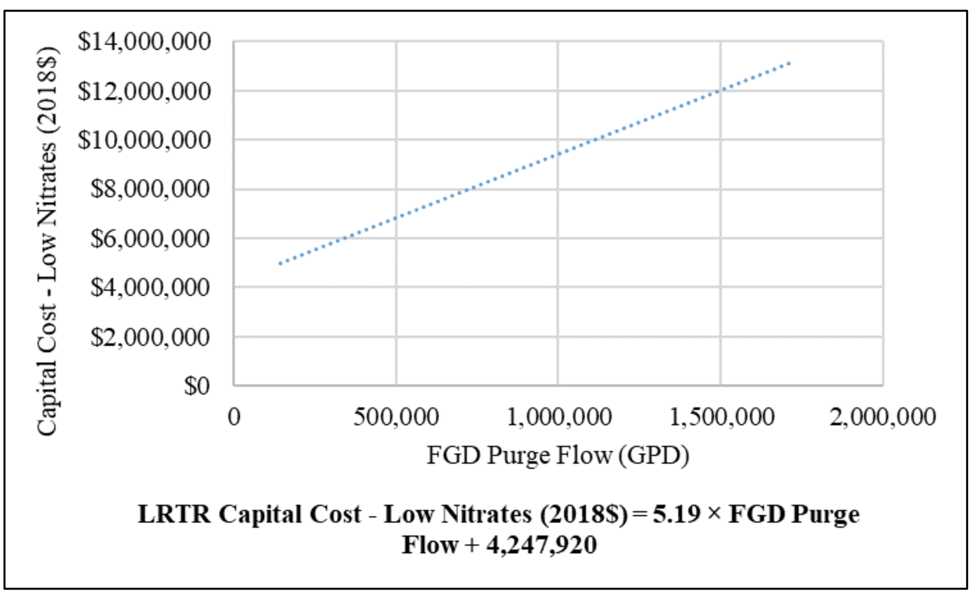
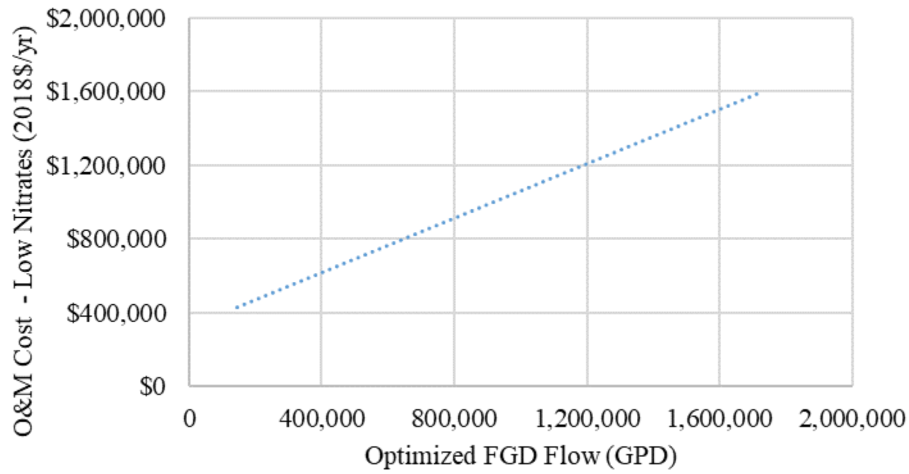
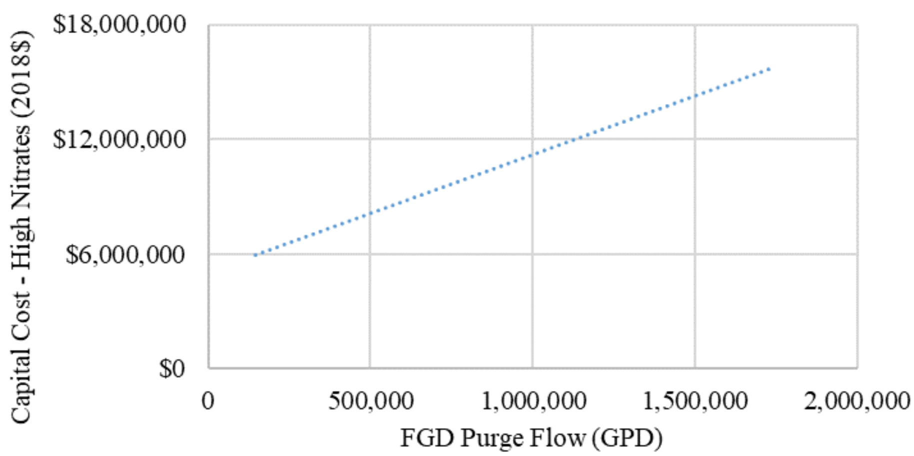


Figure 5-9. LRTR Capital Cost Curve – Low Nitrates



LRTR O&M Cost - Low Nitrates (2018$/yr) = 0.735 × Optimized FGD Flow + 326,662

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



LRTR Capital Cost - High Nitrates (2018$) = 6.15 × FGD Purge Flow + 5,052,675

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

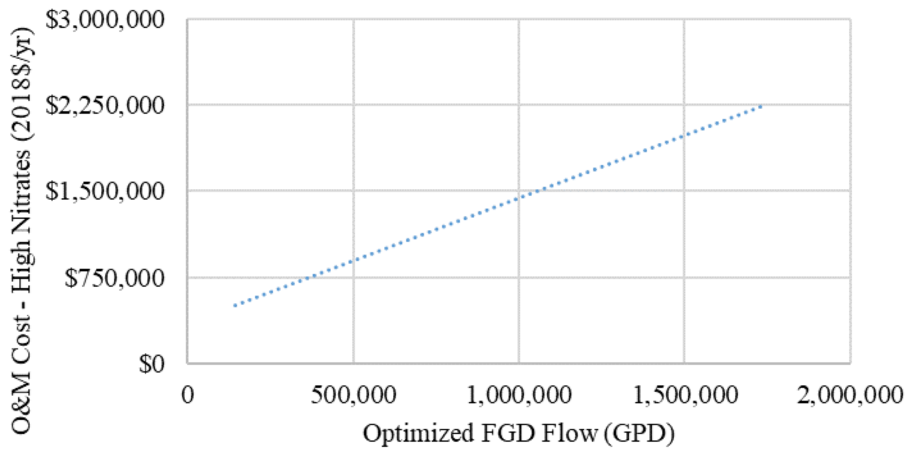


Figure 5-12. LRTR O&M Cost Curve – High Nitrates

Recurring Costs

For all plants that are expected to incur costs beyond compliance monitoring, 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), 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 [a]	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.

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

Treatment in Place	Cost Incurred
Chemical Precipitation followed by LRTR or HRTR	Compliance monitoring costs.
Evaporation [b]	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.

5.2.4 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:

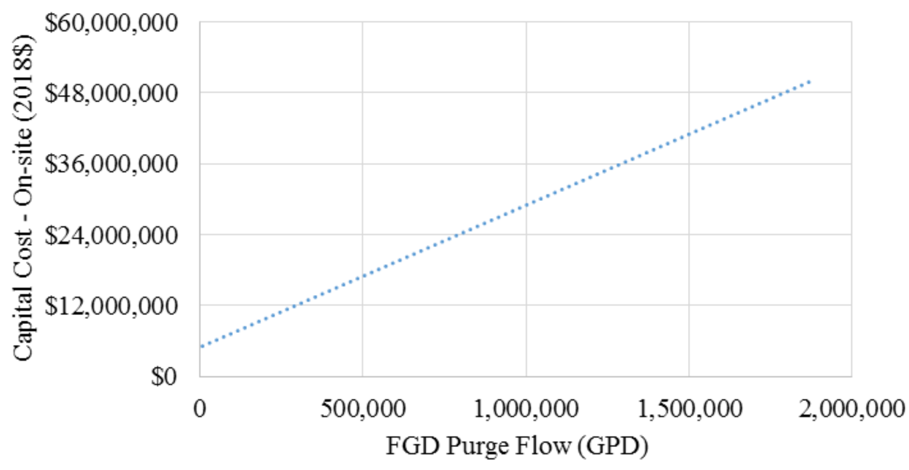
- Purchased Equipment Costs.
  - Anoxic/anaerobic biological system.
  - Tanks.
  - Pumps.
  - Heat exchanger (for applicable plants).
  - Backwash system.
  - Chemical feed systems.
  - Pretreatment system (for denitrification at applicable plants).
  - Pollutant monitoring and analysis (including a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

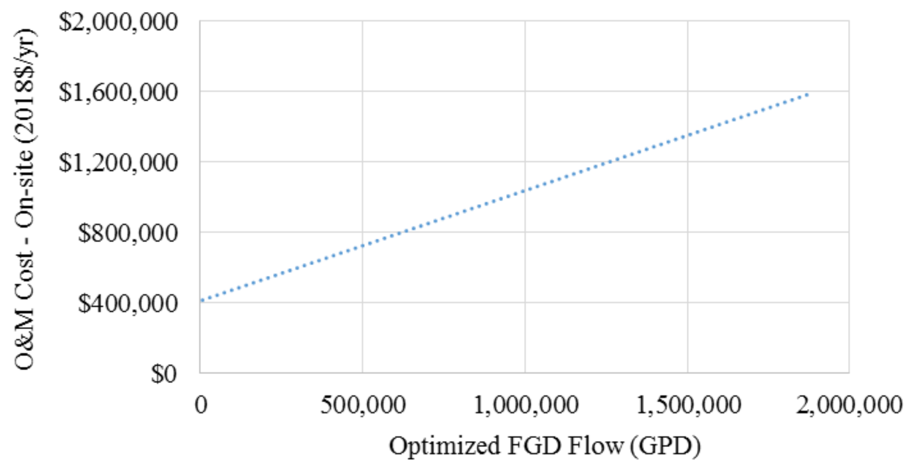
Plant-Level Capital and O&M Cost

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, 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, 2020j). Based on data received following promulgation of the 2015 rule, EPA adjusted HRTR costs to account for increased installation costs. EPA also converted the 2015 rule costs from a cost basis of 2010 dollars to 2018 dollars. 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, 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.



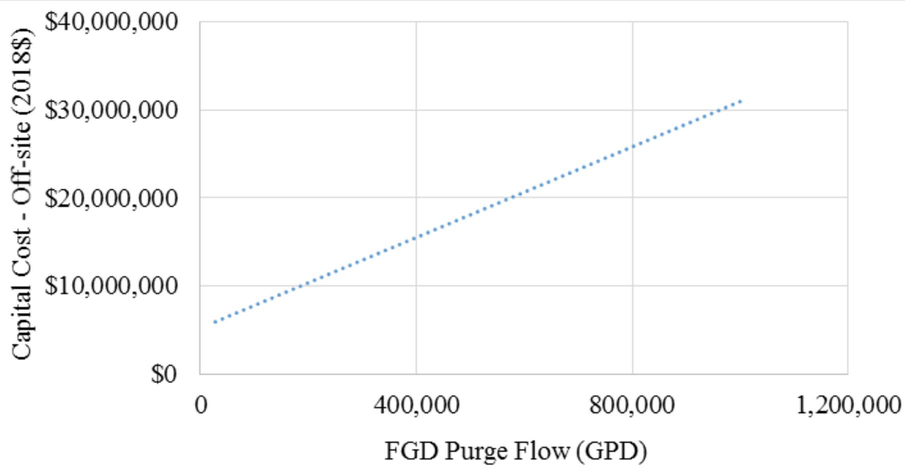
HRTR Capital Cost with On-site Transport/Disposal (2018$) = 24.03 × FGD Purge Flow + 4,897,052

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



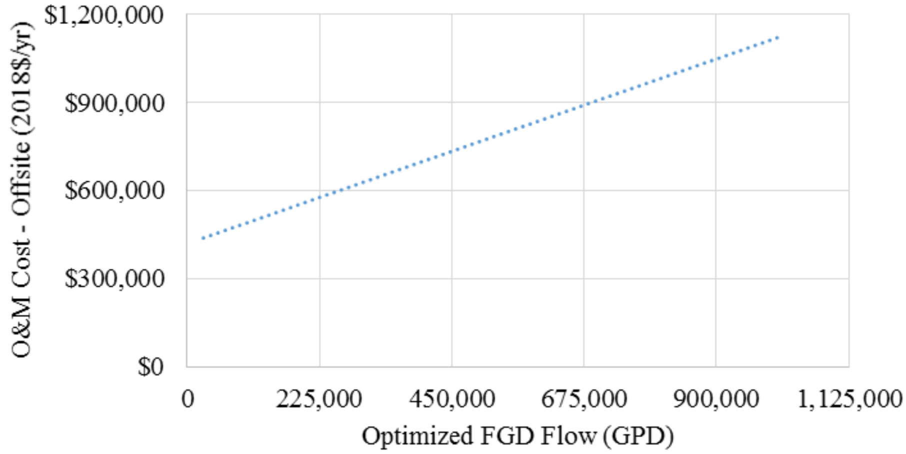
HRTR O&M Cost with On-site Transport/Disposal (2018$/yr) = 0.6265 × Optimized FGD Flow + 412,355

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



HRTR Capital Cost with Off-site Transport/Disposal (2018$) = 25.72 × FGD Purge Flow + 5,230,612

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



HRTR O&M Cost with Off-site Transport/Disposal (2018$/yr) = 0.6977 × FGD Purge Flow + 421,444

Figure 5-16. HRTR O&M Cost Curve – Off-site Transport/Disposal

For plants with a nitrate/nitrite concentration in the FGD purge at or above 100 mg/L, 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). EPA used low nitrates curves to estimate costs for all plants except for the subset of plants where sampling data from the Analytical Database and the Steam Electric Survey demonstrated nitrate/nitrite concentrations at or above 100 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, 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, 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 [a]	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 [b]	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 <u>Cost Methodology for Membrane Filtration</u>

The design basis for the membrane technology option includes pretreatment with chemical precipitation, membrane filtration, and concentrate (i.e., brine) management. EPA updated costs for encapsulation of the membrane reject using encapsulation and supplemented these costs with two additional concentrate management alternatives:

- Thermal treatment of the brine using crystallization.
- Disposal of the brine using commercial injection wells (i.e., deepwell injection).

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.

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 with chemical precipitation, membrane filtration, concentrate management, and disposal of solids. The design basis to estimate costs for membrane filtration includes both chemical precipitation cost components (see Section 5.2.2) and membrane cost components. The membrane treatment technology basis includes the following cost components:

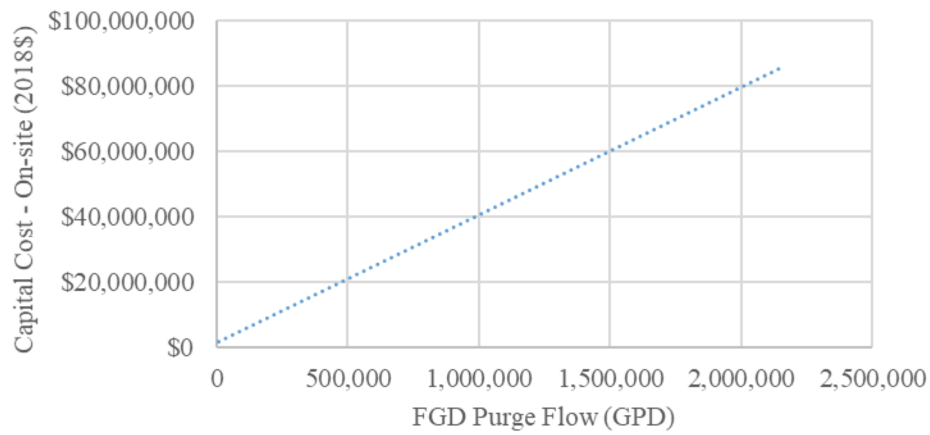
- Purchased Equipment Costs.
  - Membrane filtration skids.
  - Tanks.
  - Pumps.
  - Concentrate management equipment: For encapsulation, brine mixing skid. For crystallization, crystallizer body, heat exchanger, vapor condenser, compressors, and ducting. Deepwell injection does not have any associated purchased equipment costs.
- 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. [28]

The following sections describe the cost methodology for each concentrate management alternative evaluated as part of the membrane filtration option and present the cost curves EPA used to estimate plant-level compliance costs. Throughout the remaining sections of this development document, the term "membrane filtration" refers to the membrane filtration technology option using encapsulation as the concentrate management alternative as it was estimated to be the least costly brine management alternative at all plants.

[28] Where necessary, these transportation and disposal costs include a capital and O&M component. For disposal of encapsulated or crystallized material in on-site landfills, costs to maintain and expand an existing landfill and to transport material to the landfill are included. For disposal of encapsulated or crystallized material in off-site landfills, costs to use commercial landfills and to transport material to the landfill are included. For disposal of brine via deepwell injection, costs to use commercial wells and transport material are included.

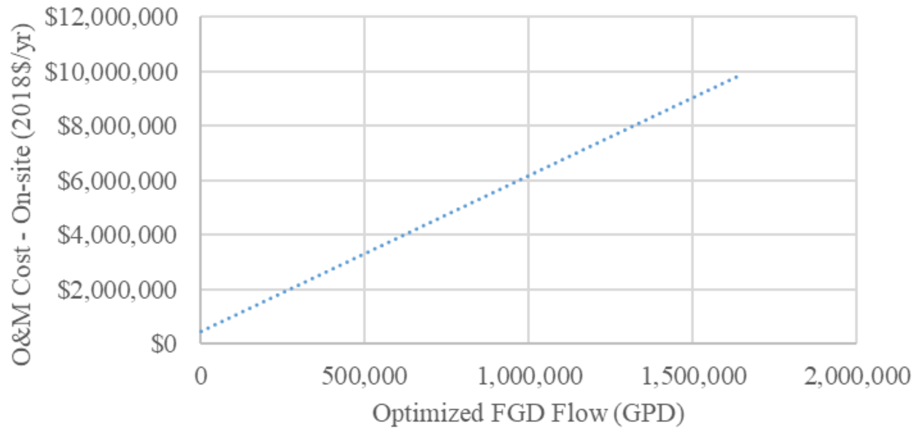
Plant-Level Capital and O&M Cost: Membrane Filtration with Encapsulation

EPA estimated pretreatment costs for a chemical precipitation system using the equations found in Section 5.2.3. Plants with existing treatment more advanced than surface impoundments were considered to have sufficient pretreatment for effective treatment through the membrane. For these plants, membrane filtration and encapsulation cost data (not including pretreatment) 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, 2020k). Similar to methodologies for other treatment technologies, EPA constructed curves to differentiate between on-site and off-site transportation and disposal. Costs for all plants were estimated using the Membrane Filtration with Encapsulation curves (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,



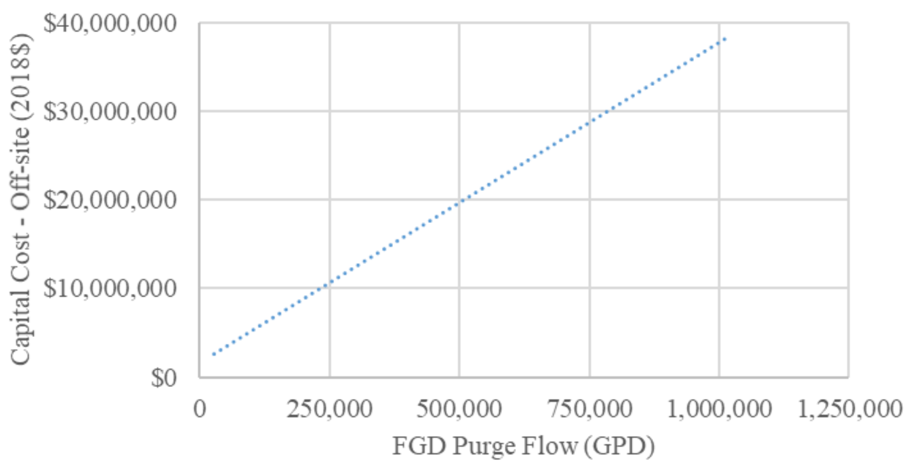
Membrane Filtration with Encapsulation Capital Cost with On-site Transport/Disposal (2018$) = 39.0 × FGD Purge Flow + 1,627,211

Figure 5-17. Membrane Filtration with Encapsulation Capital Cost Curve – On-site Transport/Disposal



Membrane Filtration with Encapsulation O&M Cost with On-site Transport/Disposal (2018$/yr) = 5.73 × Optimized FGD Flow + 464,318

Figure 5-18. Membrane Filtration with Encapsulation O&M Cost Curve – On-site Transport/Disposal



Membrane Filtration with Encapsulation Capital Cost with Off-site Transport/Disposal (2018$) = 36.0 × FGD Purge Flow + 1,661,715

Figure 5-19. Membrane Filtration with Encapsulation Capital Cost Curve – Off-site Transport/Disposal

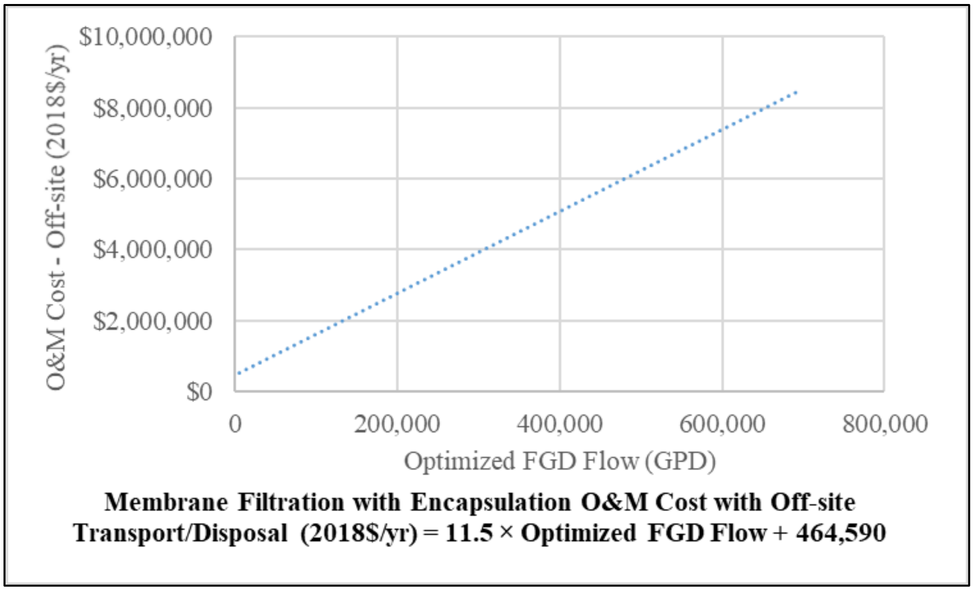


Figure 5-20. Membrane Filtration with Encapsulation O&M Cost Curve – Off-site Transport/Disposal

Plant-Level Capital and O&M Cost: Membrane Filtration with Crystallization

EPA estimated pretreatment costs for a chemical precipitation system using the equations found in Section 5.2.3. Plants with existing treatment more advanced than surface impoundments were considered to have sufficient pretreatment for effective treatment through the membrane. Membrane filtration and crystallization cost data (not including pretreatment) 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, 2020l). Similar to methodologies for other treatment technologies, EPA constructed curves to differentiate between on-site and off-site transportation and disposal. Costs for all plants were estimated using the Membrane Filtration with Crystallization curves (see Figure 5-21 and Figure 5-23 for capital cost curves and Figure 5-22 and Figure 5-24 for O&M cost curves). To estimate plant-specific capital and O&M costs, 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.

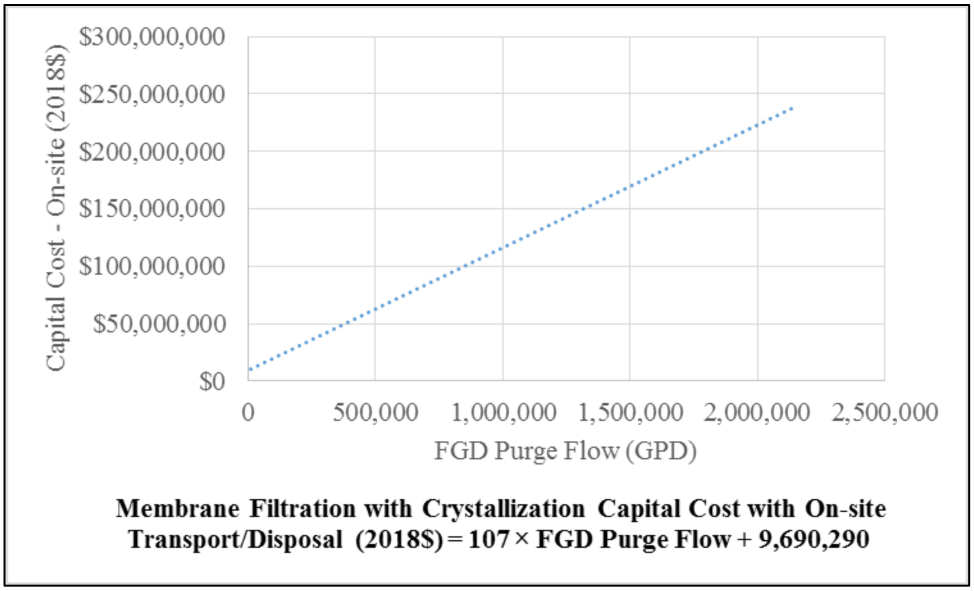


Figure 5-21. Membrane Filtration with Crystallization Capital Cost Curve – On-site Transport/Disposal

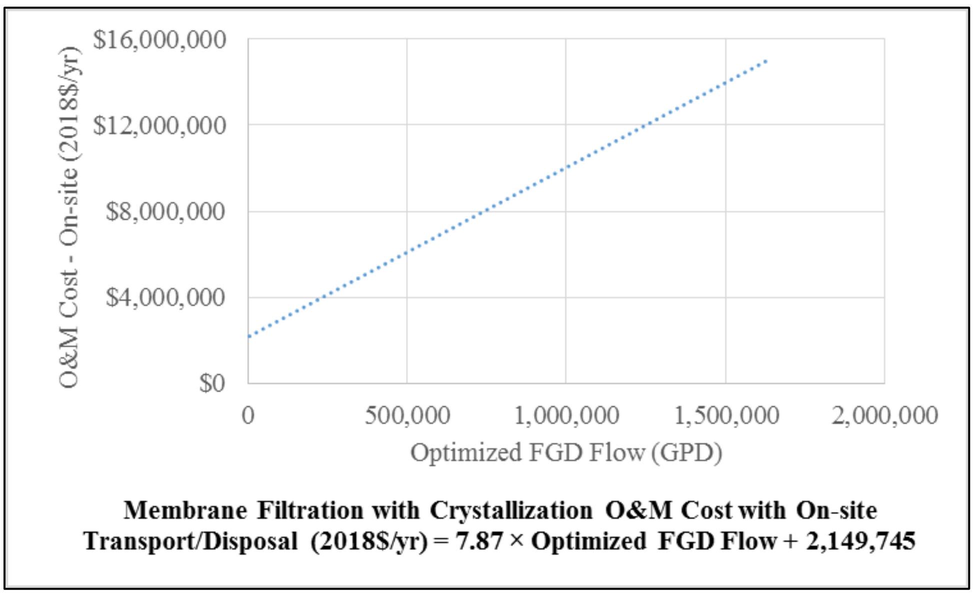


Figure 5-22. Membrane Filtration with Crystallization O&M Cost Curve – On-site Transport/Disposal

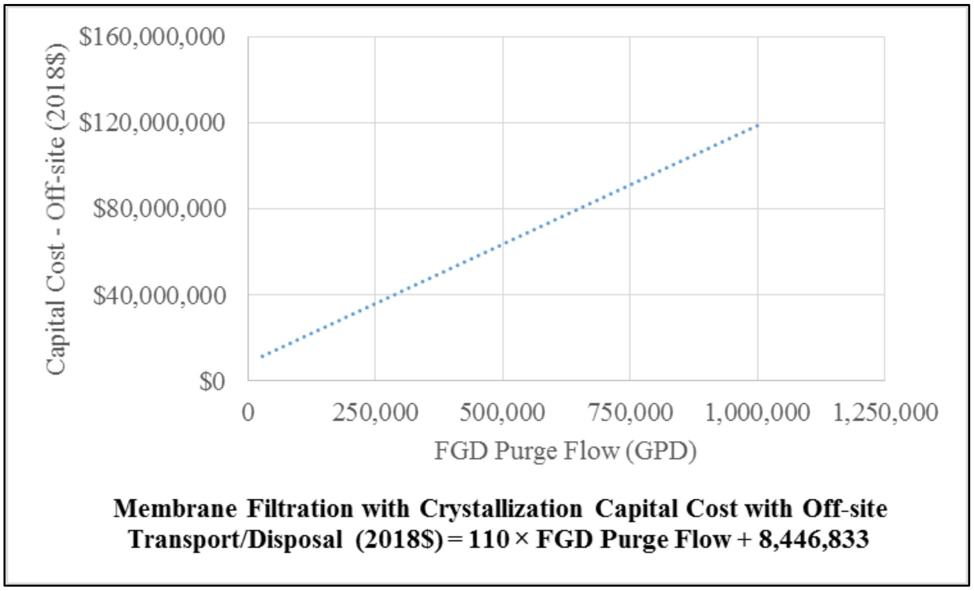


Figure 5-23. Membrane Filtration with Crystallization Capital Cost Curve – Off-site Transport/Disposal

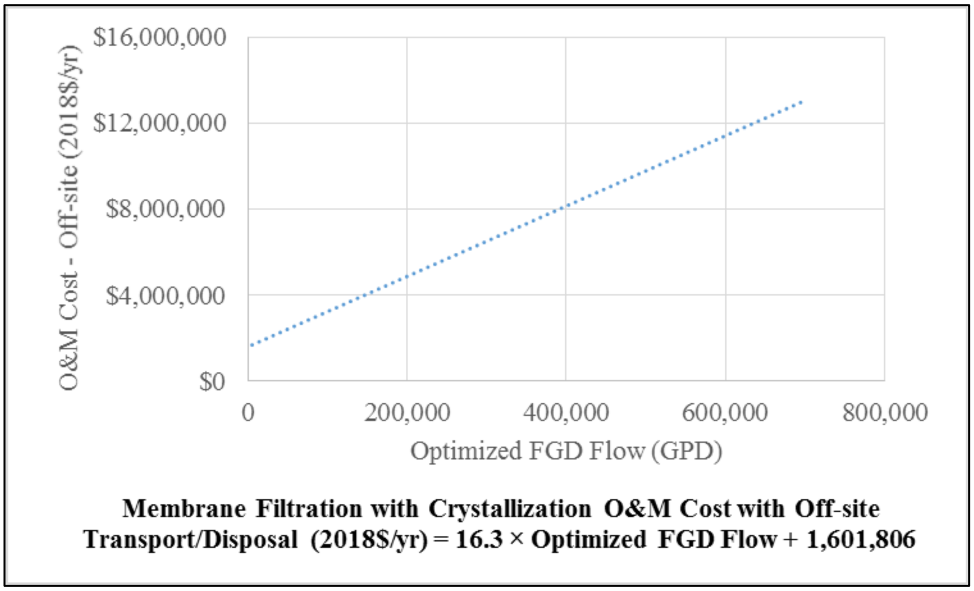
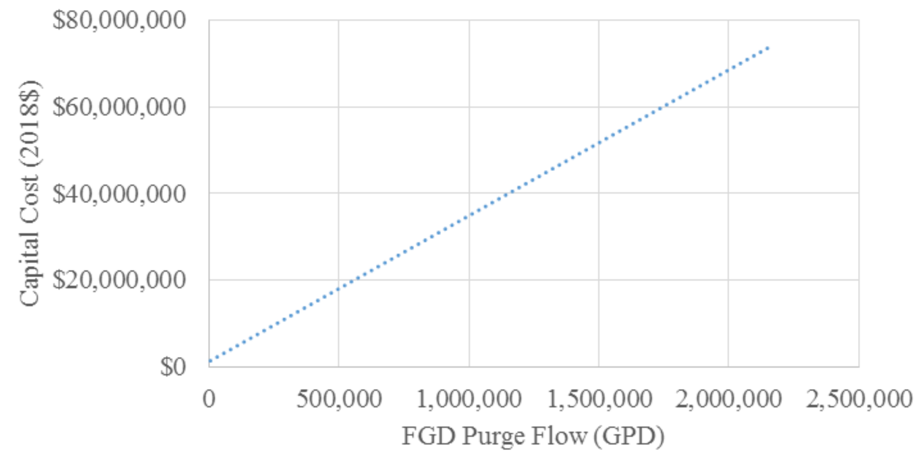


Figure 5-24. Membrane Filtration with Crystallization O&M Cost Curve – Off-site Transport/Disposal

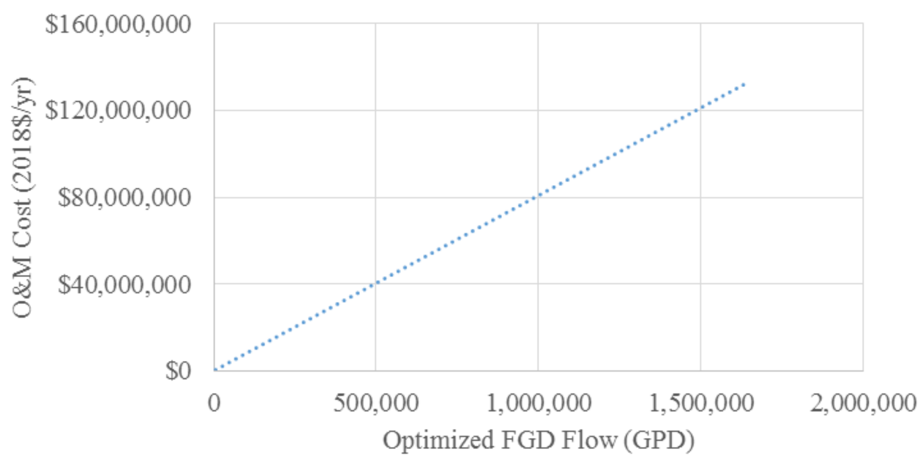
Plant-Level Capital and O&M Cost: Membrane Filtration with Deepwell Injection

EPA estimated pretreatment costs for a chemical precipitation system using the equations found in Section 5.2.3. Plants with existing treatment more advanced than surface impoundments were considered to have sufficient pretreatment for effective treatment through the membrane. Because there are no capital costs associated with deepwell injection, only membrane filtration cost data (not including pretreatment) were used to establish a relationship between capital costs and FGD purge flow rates (ERG, 2020m). Membrane filtration and deepwell injection cost data were used to establish a relationship between O&M costs and optimized FGD flow rates (ERG, 2020i). Costs for all plants were estimated using the Membrane Filtration, and Membrane Filtration with Deepwell Injection curves (see Figure 5-25 for the capital cost curve and Figure 5-26 for the O&M cost curve).



Membrane Filtration Capital Cost (2018$) = 33.7 × FGD Purge Flow + 1,086,065

Figure 5-25. Membrane Filtration Capital Cost Curve



Membrane Filtration with Deepwell Injection O&M Cost (2018$/yr) = 80.6 × Optimized FGD Flow + 431,818

Figure 5-26. Membrane Filtration with Deepwell Injection O&M Cost Curve

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, EPA calculated the plant cost for membrane filtration using any of the concentrate management alternatives based on the costs listed in Table 5-6. See Section 5.2.2 and Table 5-2 for additional details on how partial chemical precipitation costs are estimated.

Table 5-6. Membrane Filtration 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 [a]	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 filtration technology option. EPA identified one plant from the Steam Electric Survey data that discharges FGD wastewater to a POTW. Using the POTW-specific rate structures, EPA estimated the annual costs incurred by this plant for discharging to a POTW and deducted these annual costs (ERG, 2020k).

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. 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 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).

EPA used Steam Electric Survey data to identify plants that have at least one impoundment containing FGD wastewater and at least one EGU not designated as retired or planned. For those plants that have upgraded the FGD wastewater treatment system since the 2015 rule, EPA assumed that their impoundments would cease operation.[29] EPA estimated plant-level costs for operating impoundments based on the total amount of FGD solids currently handled wet at the plant. 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.

FGD Impoundment Operating Annual Cost Savings

EPA estimated the FGD impoundment operating cost savings by first calculating the plant megawatt (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 EGUs 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

[29] 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).

Where:

Impoundment Operating Unitized Cost	=	The unitized annual cost to operate a combustion residual impoundment. 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, 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. 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 (16,760 mg/L) (ERG, 2015).

FGD Earthmoving Annual Cost Savings

To calculate FGD earthmoving cost savings, 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, 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. 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 EPA Steam Electric Rulemaking effort (16,760 mg/L) (ERG, 2015).

FGD Earthmoving Recurring Costs

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. 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. 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

EPA estimated costs associated with high recycle rate for this final rule. EPA also estimated costs for zero discharge, which reflects requirements for BA transport water from the 2015 rule. These zero discharge costs are referred to here after as baseline costs. As described in the preamble, EPA established a low utilization subcategory. Low utilization is defined as a two-year average capacity utilization of less than 10 percent. For the EGUs defined as low utilization, EPA estimated costs associated with a best management practices (BMP) plan instead of the high recycle rate technology. EPA estimated the costs associated with installing additional handling or treatment technologies that eliminate or reduce the discharge of BA transport water. EPA then compared these costs to the cost to meet 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 EPA used as the basis for the three bottom ash technology options considered. EPA also estimated the cost savings associated with plants ceasing operation of impoundments currently used for the treatment of BA transport water (see Section 5.3.7).

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

Technologies	Technology Options		
	Baseline	**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 [a] (Section 5.3.6)			✓

a – Applied only to plants with EGUs with a two-year average capacity utilization of less than 10 percent, excluding plants with a generation capacity less than or equal to 50 MW.

EPA used MDS and rMDS as the two main bases for estimating compliance costs. For all EGUs discharging BA transport water from impoundment-based wet sluicing systems, EPA first estimated costs to convert to an MDS and to an rMDS. 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 EGU house configuration.[30]) 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.[31]

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

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

- rMDS (away from the EGU).
- Sump.
- Recycle pumps

[30] There are alternative ash handling technologies to the MDS and rMDS that can alleviate these issues (e.g., pneumatic bottom ash handling, compact submerged conveyors) 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.

[31] Consistent with the approach used for the 2015 rule, for plants where EPA is aware that physical constraints preclude installation of the MDS technology, EPA based costs on rMDS.

- Chemical feed system.[32]
- Semi-dry silo.

For baseline costs, 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. EPA applied these costs to plants currently operating an rMDS, as well as any other plants estimated to install the technology.

EPA estimated a cost to prepare and implement a BMP plan for EGUs with low utilization.[33] These costs include the initial development and annual review of a BMP plan to recycle as much BA transport water as determined practicable, and the capital and O&M costs for pumps and piping associated with the recycle system.

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

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 of implementing BA transport water technologies, 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 EGU capacity or bottom ash generation (ERG, 2020b). To establish the set of inputs, EPA compiled EGU-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 BA transport water.

As part of the 2015 rule, EPA developed a similar set of inputs from the Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data to calculate compliance costs. For the final rule, EPA updated the input values using additional information gathered from industry, public comments on the proposed rule, and information available from the Department of Energy and NPDES permits (see Section 2). EPA developed a list of EGUs expected to incur bottom ash compliance costs by identifying plants that discharge BA transport water, taking into account changes made to EGU handling systems, EGU retirements, and EGU conversions (to a fuel other than coal)since the 2015 rule. EPA also identified EGUs that have

[32] 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 such systems. However, because 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.

[33] Applied only to plants with EGUs with a two-year average capacity utilization of less than 10 percent, excluding plants with a generation capacity less than or equal to 50 MW.

announced plans to retire or convert their fuel source between December 31, 2023 and December 31, 2028. This section describes the updates to cost inputs from the 2015 rule.

Bottom Ash Production Data

For each applicable EGU, EPA estimated the amount of wet bottom ash produced in tons per year (TPY), generating capacity in MW, and net generation in MWh. EPA used bottom ash production and capacity values reported in the Steam Electric Survey as input values for estimating implementation costs for the final rule. EPA used EGU-level net generation values reported in the 2017 and 2018 EIA data to identify low utilization EGUs.

Bottom Ash Cost Type Flags

EPA used data from the Steam Electric Survey, site visits prior to the 2019 proposal, public comments, and other industry-provided data, discussed in Section 2, to identify the type of bottom ash handling systems currently operating at each plant. EPA used this information to determine what equipment or services the plants would have to acquire to apply each technology option. EPA flagged plants for one or more of the following:

- Steam electric EGUs equipped with only wet bottom ash handling systems that discharge BA transport water.
- Steam electric EGUs equipped with only wet bottom ash handling systems that discharge BA transport water and have space constraints preventing the installation of an MDS.
- Steam electric EGUs already operating an rMDS system.
- Steam electric EGUs equipped with only wet bottom ash handling systems that recycle all of their bottom ash sluice, but have the ability to discharge BA transport water from emergency outfalls.
- Steam electric EGUs operating a dry bottom ash handling system.

Landfill Data

Like the 2015 rule, 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. EPA anticipates plants with inactive on-site landfills will resume disposal of bottom ash to the landfill if necessitated by implementation of a BA transport water technology option.

Final CCR Part A Rule Decision Input Data

As discussed in Section 3.3, EPA updated the bottom ash population for changes in plant operations as a result of the CCR Part A rule. The CCR Part A rule sets requirements for managing impoundments containing CCRs. Based on the CCR Part A rule requirements, EPA expects that all plants with unlined or clay-lined impoundments will alter how they operate their current CCR impoundments by either rerouting CCR waste, installing new CCR-compliant impoundments, or installing tank-based treatment. EPA developed a methodology to use the

EPA impoundment liner data , described in Section 3.3, to predict operational changes at each coal-fired power plant under the CCR Part A rule. EPA identified plants with unlined or clay-lined CCR surface impoundments. Where all surface impoundments at the plant are impacted by the CCR Part A Rule, EPA assumed that the plant would install tank-based treatment or handling. For bottom ash, this tank-based handling is assumed to be one of two systems: either a dry bottom ash handling system, consistent with the MDS system, or a high recycle rate bottom ash handling system, consistent with the rMDS system. EPA selected the technology with the lowest annualized costs for each plant to determine the technology likely to be installed. See Table 5-8 for details on how plants installing tank-based handling under the CCR Part A rule were reflected in bottom ash cost and loadings estimates.

Table 5-8. ELG Bottom Ash Changes Accounting for CCR Part A Rule

CCR Part A Rule Decision	ELG Technology Basis Assumptions	Effect on ELG Costs	Effect on ELG Loadings
All CCR surface impoundments expected to close or retrofit.	Plant installs a dry or high recycle rate bottom ash handling system on all EGUs (i.e., MDS or rMDS).	Bottom ash handling treatment-in-place (MDS or rMDS based on lowest annualized cost). For baseline, plants with rMDS installations incur costs associated with a reverse osmosis system.[a]	Bottom ash handling treatment-in-place (MDS or rMDS based on lowest annualized cost). For all regulatory options, plants with rMDS installations have pollutant loadings associated with the purge stream.
At least one CCR surface impoundment is not expected to close or retrofit.	No change.	No change.	No change.
No data.	No change.	No change.	No change.

a – Plants that install rMDS to comply with the CCR Part A rule also incur costs to install a reverse osmosis system to treat a slipstream of the recirculating BA transport water to comply with the 2015 rule standards (i.e., baseline).

EPA identified 46 plants discharging BA transport water operating all unlined or clay-lined CCR surface impoundments. Of these, 14 plants operate bottom ash wet handling systems as closed-loop systems or already operate high recycle rate systems. EPA expects the remaining 32 plants to install a dry or high recycle rate bottom ash handling system under the CCR Part A rule.

5.3.2 Cost Methodology for Mechanical Drag System

EPA estimated capital, O&M, and 3-year recurring costs associated with installing an MDS for all steam electric EGUs equipped with wet bottom ash handling systems that discharge BA transport water. EPA used cost data from the 2015 rule to develop capital cost curves for on-site and off-site disposal as a function of EGU capacity. EPA developed O&M cost curves for on-site and off-site disposal as a function of the amount of wet bottom ash produced. 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, 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), EPA generated a set of cost curves for each transportation and disposal method (see Figure 5-27 and Figure 5-29 for capital costs and Figure 5-28 and Figure 5-30 for O&M costs).

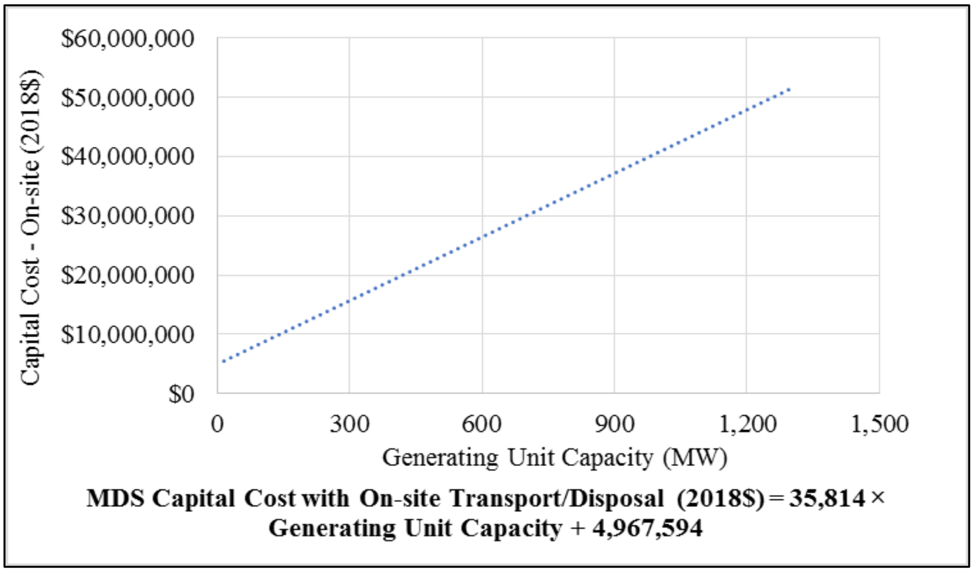


Figure 5-27. MDS Capital Cost Curve – On-site Transport/Disposal

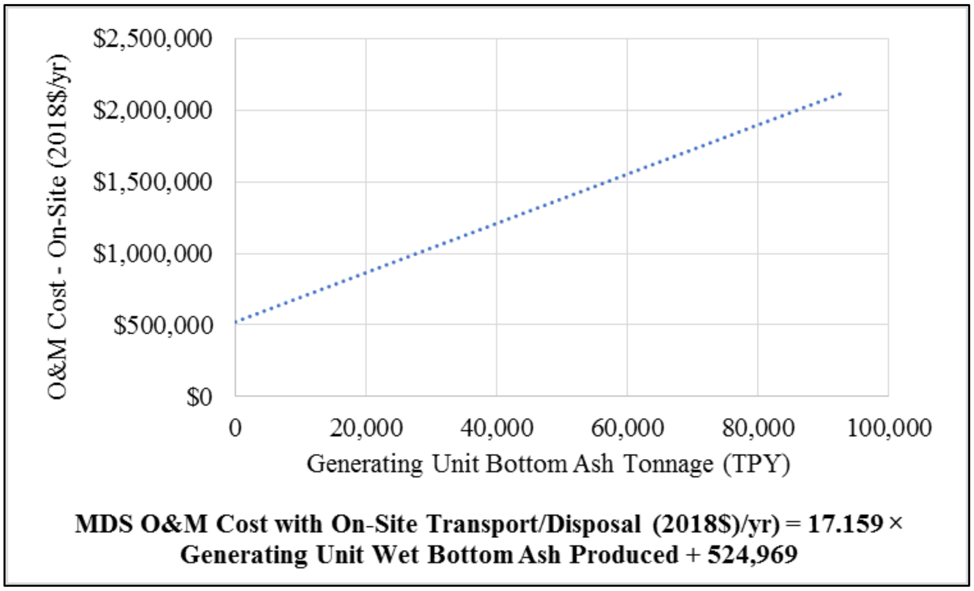
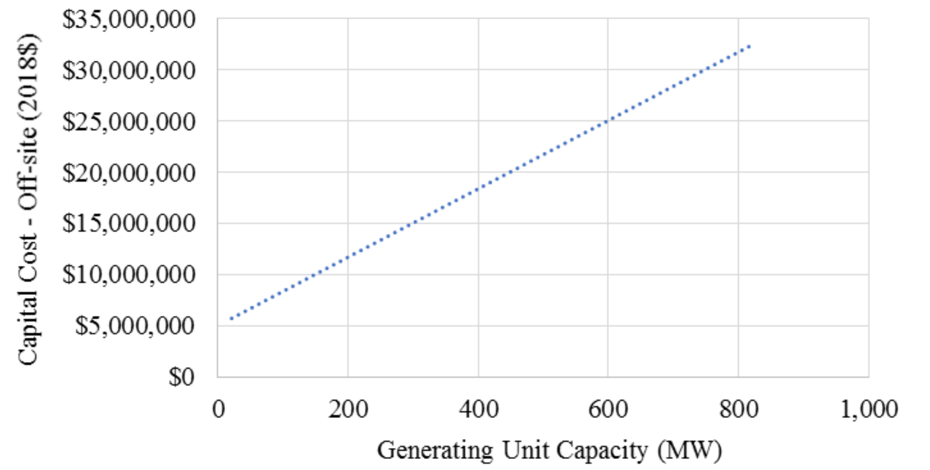
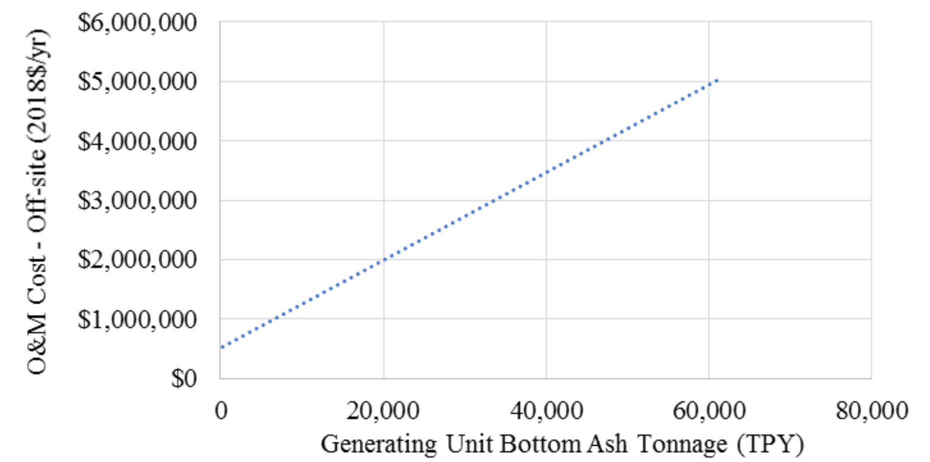


Figure 5-28. MDS O&M Cost Curve – On-site Transport/Disposal



MDS Capital Cost with Off-site Transport/Disposal (2018$) = 33,500 × Generating Unit Capacity + 5,004,227

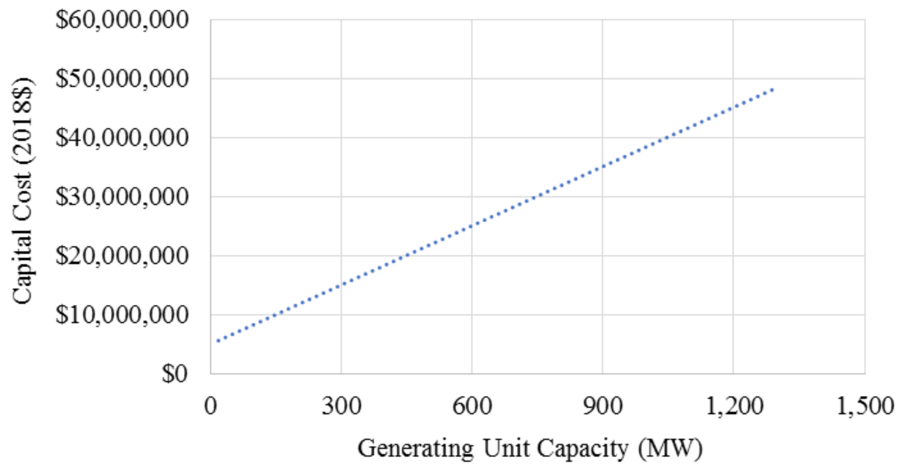
Figure 5-29. MDS Capital Cost Curve – Off-site Transport/Disposal



MDS O&M Cost with Off-site Transport/Disposal (2018$/yr) = 73.713 × Generating Unit Wet Bottom Ash Produced + 528,126

Figure 5-30. 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 final rule. EPA calculated the unit-level MDS capital costs for plants operating CCR storage impoundments using the cost curve in Figure 5-31 below.



MDS Capital Cost Excluding Transport/Disposal (2018$) = 33,500 × Generating Unit Capacity + 5,004,227

Figure 5-31. MDS Capital Cost Curve – Excluding Transport/Disposal

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 BA transport water to a POTW receive a cost savings for eliminating BA transport water discharges and ceasing discharges to the POTW. EPA identified one plant 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, EPA estimated the annual costs incurred by this plant for discharging to a POTW and deducted these annual costs (ERG, 2020c).

For each EGU, 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. EPA calculated the MDS capital and O&M compliance costs using the EGU-specific data and corresponding equations.

Recurring Costs

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.[34]

[34] The EGU can continue to operate during replacement of the drag chain components.

MDS 3-Year Costs (2018$) = $206,000

Equation 5-13

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 Baseline

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. EPA used cost data from the 2015 rule to develop capital cost curves for on-site and off-site disposal as a function of EGU capacity. 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. 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.

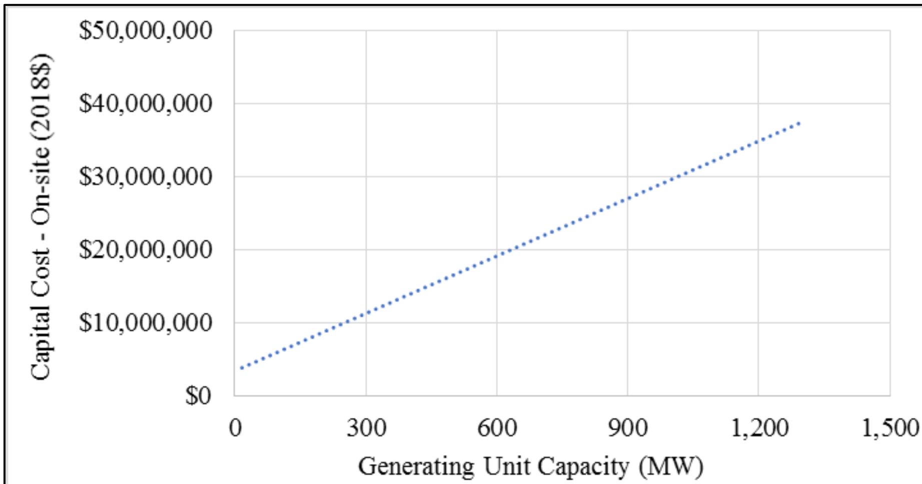
   – Contingency.

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, 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), EPA generated a set of cost curves for each transportation and disposal method (see Figure 5-32 and Figure 5-34 for capital costs and Figure 5-33 and Figure 5-35 for O&M costs).



rMDS Capital Cost with On-site Transport/Disposal (2018$) = 26,242 × Generating Unit Capacity + 3,449,512

Figure 5-32. rMDS Capital Cost Curve – On-site Transport/Disposal

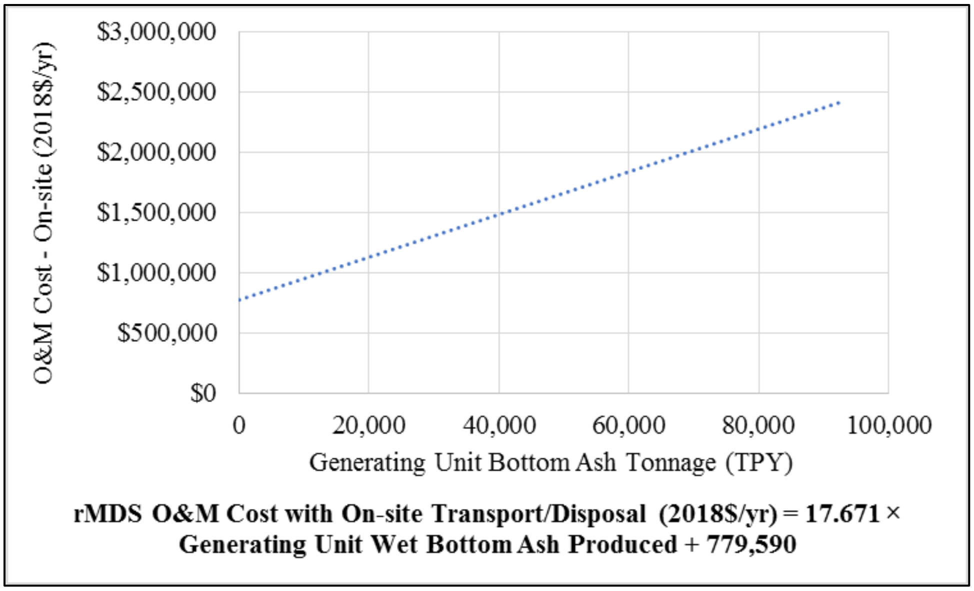


Figure 5-33. rMDS O&M Cost Curve – On-site Transport/Disposal

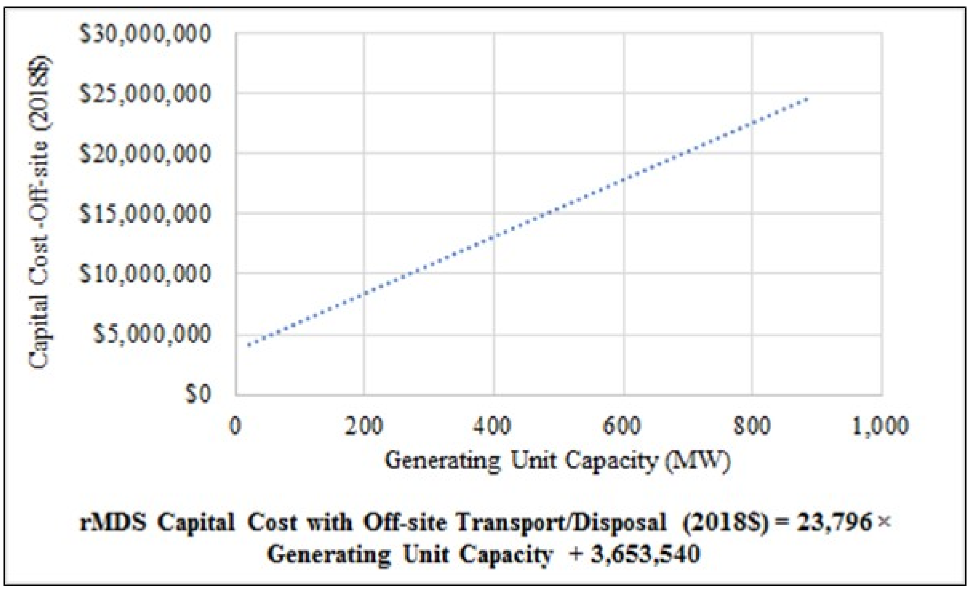
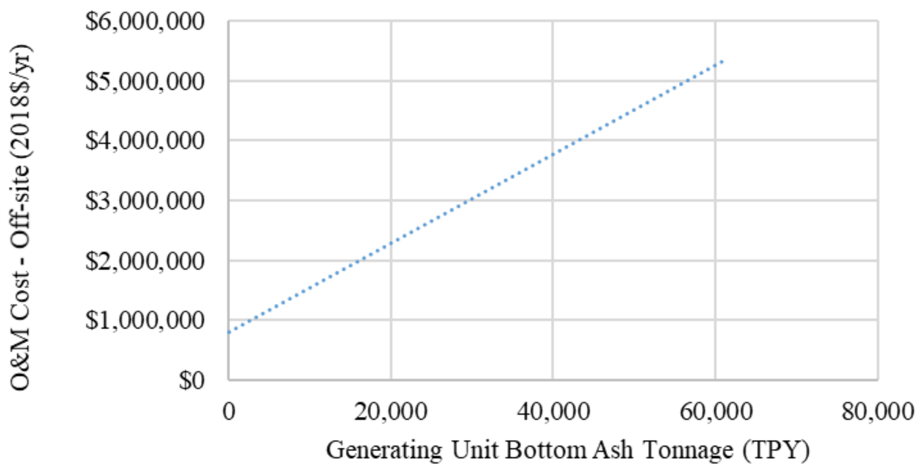


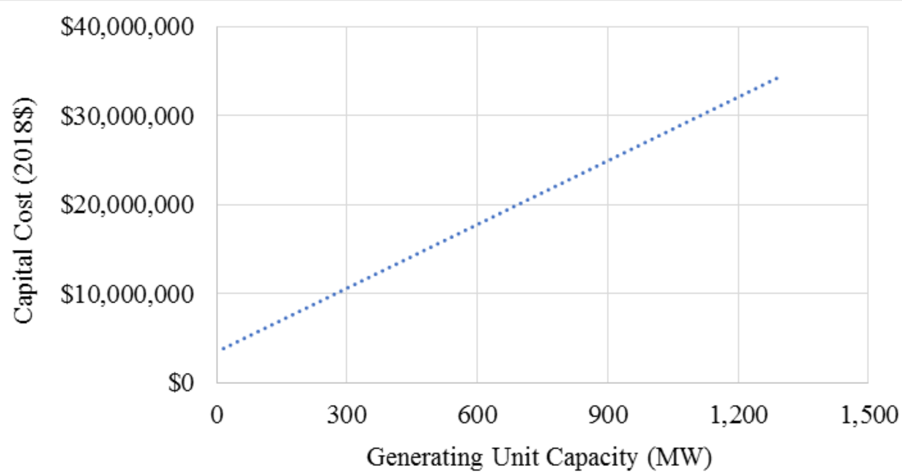
Figure 5-34. rMDS Capital Cost Curve – Off-site Transport/Disposal



rMDS O&M Cost with Off-site Transport/Disposal (2018$/yr) = 74.326 × Generating Unit Wet Bottom Ash Produced + 794,285

Figure 5-35. 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 final rule. EPA calculated the unit-level MDS capital costs for plants operating CCR storage impoundments using the cost curve in Figure 5-36 below.



rMDS Capital Cost Excluding Transport/Disposal (2018$) = 23,874 × Generating Unit Capacity + 3,548,689

Figure 5-36. rMDS Capital Cost Curve – Excluding Transport/Disposal

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 EGU in the costed population, 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. EPA calculated the rMDS capital and O&M compliance costs using the EGU-specific data and corresponding equations.

Additional Baseline Costs

The cost methodology for all rMDS systems includes chemical addition equipment to manage the 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 baseline costs, 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 indicate 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 EPA does not have sufficient plant-specific data to determine which plants may need RO treatment, 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 BA 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, 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 RO reject, or brine, requires disposal and EPA included O&M costs associated with hauling the brine offsite to a centralized waste treatment (CWT) facility for disposal.

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 EGU or other EGU house impediment; or (3) the cost to install rMDS is lower than the cost for MDS. 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. EPA calculated these additional costs at the plant level because plants with multiple rMDS units will treat all BA transport water slipstreams generated at the plant with one treatment system (ERG, 2020c).

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

Equation 5-15

$$\text{Additional Baseline rMDS O\&M Costs} = \text{Total RO O\&M Costs} + \text{Total Tank/Pipe/Pump O\&M Costs} + \text{Transportation/Disposal Costs}$$

Equation 5-16

RO Capital and O&M Costs

To calculate the plant-level RO capital and O&M costs, 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, 2020c). For plants with a total capacity less than or equal to 200 MW, EPA estimated a total rMDS volume of 175,000 gallons. For plants with a total generating capacity greater than 200 MW, 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:

Plant-Level Capacity	=	The sum of all plant EGU capacities flagged for bottom ash compliance costs (in MW).

Based on information provided by industry, 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).

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

Equation 5-18

Where:

Total rMDS Volume	=	Total volume of all rMDS expected to be operating the plant (in gallons).

EPA estimated plant-level RO capital and O&M costs as a function of the slipstream flow rate using 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

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

Equation 5-20

Where:

Slipstream Flow	=	Daily flow rate of rMDS slipstream (in GPM) (see Equation 5-18).

To calculate transportation and disposal costs, EPA included O&M costs associated with hauling the brine off site for disposal at a CWT.

EPA calculated brine flow rate based on the average recovery for FGD wastewater provided by membrane treatment vendors. EPA estimated the weight of the brine based on the weight of the solids in the brine and the weight of the water using Equations 5-21, 5-22, and 5-23. Solids in the brine were estimated based on the average TSS concentration in BA transport water for the entire purge flow (this assumes that all solids from the bottom ash purge will be retained in the brine, which is likely an over estimate).

$$\text{Annual Brine Solids (tons/year)} = \text{Bottom Ash Purge (GPD)} \times \text{Average TSS Concentration} \times 3.78 \text{ L per gal} \times 0.001 \text{ g per mg} \times (1.102 \times 10^{-6} \text{ tons/g}) \times 365 \text{ dpy}$$

Equation 5-21

Where:

Bottom Ash Purge	=	10 percent of the total bottom ash system volume.
Average TSS Concentration	=	Average TSS concentration in BA transport water (see Table 6-2), 13.4 mg/L.

$$\text{Annual Brine Water Weight (tons/year)} = \text{Brine Flow (GPD)} \times 0.00417 \text{ tons per gal} \times 365 \text{ dpy}$$

Equation 5-22

$$\text{Annual Brine Weight (tons/year)} = \text{Annual Brine Solids} + \text{Annual Brine Water Weight}$$

Equation 5-23

EPA estimated the annual cost of transporting brine solids to a CWT facility using the 2015 methodology for off-site transportation, which is based on transportation of solids to an off-site landfill located 25 miles from the plant (Equation 5-24).

$$\text{Transportation Cost (2018\$)} = \text{Annual Brine Weight} \times \$9.23 \text{ per ton} \times (\text{2018 Index} / \text{2011 Index})$$

Where:

2011 Index	=	191.2
2018 Index	=	215.8

Equation 5-24

EPA estimated disposal costs using the brine flow and a disposal cost of $0.167/gallon (2005$) using Equation 5-25.

$$\text{Disposal Cost (2018\$)} = \text{Brine Flow (GPD)} \times \$0.167 \text{ per gallon} \times (\text{2018 Index} / \text{2005 Index})$$

Equation 5-25

Where:

2005 Index	=	151.6
2018 Index	=	215.8

To estimate the annual cost for brine transportation and disposal, EPA summed the transportation and disposal costs using Equation 5-26.

$$\text{Brine T\&D Annual Cost} = \text{Transportation Cost} + \text{Disposal Cost}$$

Equation 5-26

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

Surge Tank, Pipe, and Pump Costs

EPA estimated the total capital costs associated with operating the surge tank, pumps, and piping needed to hold and recirculate RO distillate, or any BA 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 5-27 and Equation 5-28.

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

Equation 5-27

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

Equation 5-28

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 RSMeans Historical Cost Indices (Gordian, 2018).

To estimate tank cost, EPA first estimated the size of the required surge tank using Equation 5-29. Tank size is based on the largest EGU at the plant (defined by capacity in MW) and the expectation that only one EGU will need to empty the bottom ash hopper at any one time. 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.

$$\text{Tank Size (gallons)} = 63 \times \text{Unit Capacity} \times \text{Tank Sizing Factor}$$

Equation 5-29

Where:

Unit Capacity	=	Capacity of the EGU (in MW).
Tank Sizing Factor	=	1.5.

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 5-30.

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

Equation 5-30

Where:

Tank Size	=	Size of the surge tank (in gallons)
2011 Cost Index	=	185
2018 Cost Index	=	215.8

For tanks greater than 50,000 gallons in size, see Equation 5-31:

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

Equation 5-31

Where:

Tank Size	=	Size of surge tank (in gallons)
2011 Cost Index	=	185

2018 Cost Index = 215.8

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.

EPA first estimated the flow from the surge tank using Equation 5-32.

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

Equation 5-32

Where:

Tank Size = Size of the surge tank (in gallons).

EPA then calculated the pump as a function of this flow, using Equation 5-33.

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

Equation 5-33

Where:

2011 Cost Index = 185.

2018 Cost Index = 215.8.

Flow = Tank size (in gallons).

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: $37,000 (2018$).

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 5-34.

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

Equation 5-34

EPA estimated the indirect capital costs by multiplying the sum of the total purchased equipment and direct capital costs by 0.43, using Equation 5-35.

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

Equation 5-35

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 5-36

To calculate the energy cost, EPA first estimated the annual energy requirement to operate the pumps, based on the 2015 rule cost methodology, using Equation 5-37.

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

Equation 5-37

Where

Flow = Daily flow rate from the surge tank (in GPM) (see Equation 5-38).

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 5-38.

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

Equation 5-38

Where:

Annual Energy Requirement = Annual energy requirement to operate pumps (in kWh/yr) (see Equation 5-37).

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

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 5-39

Where:

Flow = Daily flow rate from the surge tank (in GPM) (see Equation 5-40).

Recurring Costs

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 5-40).

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

Equation 5-40

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, 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. 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, EPA included all baseline rMDS costs except costs classified as additional zero discharge costs (see Additional Baseline Costs). 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.

In addition, to mitigate stormwater contributions to the bottom ash system, EPA added capital costs associated with constructing a roof over the conveyor system. EPA used the building cost methodology from the 2015 rule to estimate an average capital cost for all plants to install a building to house the rMDS system. EPA applied this average capital cost, $1,045,241.67 (2018$) to all plants installing a rMDS with a purge to construct a roof over the conveyor system[35] (ERG, 2020l).

5.3.5 Bottom Ash Management Cost Methodology

EPA identified several plants that operate bottom ash wet-sluicing systems as closed-loop systems. These plants did not report any discharge of BA transport water in the Steam Electric Survey. However, based on other information in the survey responses, EPA determined that these plants have retained the capability to discharge BA transport water from emergency outfalls. Therefore, EPA estimated additional costs associated with eliminating the potential future discharge of BA transport water, which survey data confirm is not typical practice. EPA estimated a one-time cost associated with consulting an engineer to eliminate the need and the

[35] EPA's methodology uses building costs, which represent a walled structure with insulation and HVAC equipment. These costs may be an overestimate for those locations, not subject to cold climates, that may only need a roof or carport type structure.

capacity to discharge BA 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, EPA estimated a one-time cost of $26,400, in 2018 dollars.

In addition to one-time costs, 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 BA transport water. Using the 2015 rule cost data and EPA's methodology for estimating rMDS chemical feed system costs, 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 two-year average capacity utilization of less than 10 percent (based on 2017 and 2018 EIA net generation data), EPA estimated costs associated with the development and implementation of a BMP plan to recycle as much BA transport water determined to be achievable. These costs include (1) the initial development of the BMP plan, (2) capital and O&M costs for pumps and piping associated with recirculation, and (3) the annual review of and revision to the BMP plan.

One-time Costs

EPA calculated the one-time cost for developing the BMP plan using Equation 5-41. The one-time cost includes an outside contractor[36] reviewing current operations and developing a BMP plan, which includes four weeks on site at the plant, and plant review and acceptance of plan.

$$\text{BMP Plan One-Time Cost (2018\$)} = \text{Contractor Labor Cost} + \text{Contractor Travel Cost} + \text{Plant Review Cost}$$

Equation 5-41

$$\text{Contractor Labor Cost (2018\$)} = \text{Number of Hours} \times \text{Contractor Rate} = \$33{,}600$$

Equation 5-42

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, $120/hr (in 2018$).

[36] 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, EPA assumed that plants would incur costs associated with an outside contractor.

Contractor Travel Cost (2018\$) = (Number of Travel Days × Hotel Cost × Escalation Rate) + (Number of Travel Days × Food Cost) + (Number of Travel Weeks x Car Rental Cost) + (Number of Trips × Airfare Costs) = \$6,549

Equation 5-43

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).
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\$).

Plant Review Cost (2018\$) = Number of Hours × Environmental Coordinator Labor Rate = \$2,091

Equation 5-44

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

EPA calculated the capital and O&M costs associated with piping and pumps to accommodate recycling BA 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, EPA calculated average capital and O&M costs using Equation 5-45.

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

Equation 5-45

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

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, EPA calculated a pump capital cost of $146,500 (2018$).

EPA estimated the total annual O&M costs associated with pumping the BA 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

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 plan and incorporating revisions, which includes a one-day site visit to the plant, and plant review and acceptance using Equation 5-46.

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

Equation 5-46

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

Equation 5-47

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, $120/hr (in 2018$).

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

Equation 5-48

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\$).

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

Equation 5-49

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. 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 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).

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 EPA had data indicating plants had installed a dry or high recycle rate bottom handling systems since the 2015 rule, EPA anticipated these plants no longer operate an impoundment for bottom ash handling. EPA also anticipates that plants whose impoundments are expected to close due to CCR Part A rule requirements will not use impoundments for bottom ash handling. EPA estimated plant-level costs for operating impoundments based on the total amount of bottom ash solids currently handled wet at the plant. EPA estimated the total bottom ash impoundment O&M cost savings using Equation 5-50.

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

Equation 5-50

Where:

Bottom Ash Impoundment Operating Cost Savings	=	Total impoundment operating cost savings (in 2010$), see Equation 5-53.
Bottom Ash Earthmoving Cost Savings	=	O&M cost associated with the earthmoving equipment required (in 2010$), see Equation 5-55.
2010 Cost Index	=	183.5.

2018 Cost Index	=	215.8.

Bottom Ash Impoundment Operating Annual Cost Savings

EPA estimated the bottom ash impoundment operating cost savings by first calculating the plant MW factor using Equation 5-51 and the plant-specific unitized cost using Equation 5-52.

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

Equation 5-51

Where:

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

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

Equation 5-52

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. 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, EPA calculated the bottom ash impoundment operating cost savings by multiplying the plant-specific unitized cost using Equation 5-53 by the amount of bottom ash produced by the plant, in tons per year (TPY), as discussed in Section 5.3.1.

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

Equation 5-53

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 EGU, and then summing the EGU-level values to the plant level.

Bottom Ash Earthmoving Annual Cost Savings

To calculate bottom ash earthmoving cost savings, 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 5-54.

Plant-Specific Front-End Loader Unitized Cost (2010$/ton) =
(Front-End Loader 2010 Unitized O&M Cost) × (Plant MW Factor)

Equation 5-54

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, EPA calculated the bottom ash earthmoving cost savings by multiplying the plant-specific unitized cost using Equation 5-55 by the amount of bottom ash tonnage produced by the plant in TPY discussed in Section 5.3.1.

Bottom Ash Impoundment Earthmoving Cost Savings = (Plant-Specific Front-End Loader Unitized Cost) × (Plant Bottom Ash Tonnage)

Equation 5-55

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 EGU, and then summing the generating-unit-level values to the plant level.

Bottom Ash Earthmoving Recurring Costs

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. 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, EPA evaluated regulatory options comprising various combinations of the treatment technologies considered for control of each wastestream. EPA estimated different compliance costs for steam electric EGUs with a specific steam electric power generating capacity, EGUs with a specific capacity utilization, and “high-flow” FGD wastewater plants. In calculating the compliance cost estimates for each regulatory option, 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, EPA first estimated plant-level FGD and bottom ash technology option compliance costs. EPA then estimated unit-level costs (including capital, O&M, 3-, 5-, 6-, and 10-year recurring costs) using Equation 5-56.

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

Equation 5-56

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 2018 Form EIA-860 data for new EGUs).
Plant-Level Capacity	=	Plant-level generating nameplate capacity in MW (from Form EIA-860 data for 2018).

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 BA transport water technologies selected as basis for each plant’s regulatory option compliance cost estimates (ERG, 2020j).

Table 5-9 and Table 5-10 present the total industry compliance cost estimates for FGD wastewater and BA transport water, respectively, by regulatory option.

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

presents the aggregated, industry-level compliance costs by regulatory option. All cost estimates are expressed in terms of pre-tax 2018 dollars and represent costs incurred once all plants and EGUs achieve compliance with the regulatory option presented. Values presented in this document do not account for the timing or exact date of implementation (e.g., when costs are incurred by the industry).

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 [a]
Baseline	61	$1,510	$70.4	NA	NA	NA	$3.51	($8.05)
A	61	$821	$62.0	NA	NA	NA	$2.61	($6.63)
B	61	$873	$67.1	NA	NA	NA	$2.61	($7.10)
C	61	$1,760	$186	NA	NA	NA	$0	($8.05)
D[b]	70	$675	$42.4	NA	NA	NA	$4.41	($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.

b – Regulatory Option D reflects the population, methodology, and costs considered for the 2019 proposed rule (see Section 5.4 of the Proposed TDD (U.S. EPA, 2019)). These values should not be used for direct comparisons to this final rule.

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 [a]
Baseline	91	$1,070	$115	$0.185	$0.617	$8.03	NA	($10.8)
A	91	$505	$53.6	$0.200	$0.617	$5.56	NA	($7.63)
B	91	$640	$67.6	$0.185	$0.617	$7.41	NA	($9.83)
C	91	$640	$67.6	$0.185	$0.617	$7.41	NA	($9.83)
D[b]	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.

b – Regulatory Option D reflects the population, methodology, and costs considered for the 2019 proposed rule (see Section 5.4 of the Proposed TDD (U.S. EPA, 2019)). These values should not be used for direct comparisons to this final rule.

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 [a]
Baseline	112[b]	$2,570	$186	$0. 185	$0.617	$8.03	$3.51	($18.8)
A	112 [b]	$1,330	$116	$0.200	$0.617	$5.56	$2.61	($14.3)
B	112 [b]	$1,510	$134	$0. 185	$0.617	$7.41	$2.61	($16.9)
C	112 [b]	$2, 400	$253	$0. 185	$0.617	$7.41	$0.00	($17.9)
D[c]	116	$2,009	$123	$0.132	$1.03	$18.3	$4.41	($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.

b – Four of these plants incur zero cost, resulting in 108 plants with non-zero estimated costs for implementation of baseline and Regulatory Options A, B, and C.

c – Regulatory Option D reflects the population, methodology, and costs considered for the 2019 proposed rule (see Section 5.4 of the Proposed TDD (U.S. EPA, 2019)). These values should not be used for direct comparisons to this final rule.

SECTION 6
POLLUTANT LOADINGS AND REMOVALS

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 (BA) transport water discharges from steam electric power plants. The best available technologies economically achievable (BAT)/ pretreatment standards for existing sources (PSES) regulatory options described in the preamble comprise various combinations of treatment technologies for controlling pollutants in each of these wastestreams. Because the 2015 rule is codified in 40 CFR 423, the pollutant removals associated with the regulatory options for the final rule 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. Therefore, 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 BA transport water discharged to surface water or through publicly owned treatment works (POTWs) to surface water under 2015 rule conditions. For the final rule, 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).[37]
- *Post-Compliance Loadings*. Pollutant loadings, in pounds per year, in FGD wastewater and/or BA transport water discharged to surface water or through POTWs to surface water after full implementation of the final rule technology options. EPA estimates post-compliance pollutant loadings with the expectation that all steam electric power plants subject to the requirements of the final 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 EPA used to estimate pollutant loadings and removals for each of the technology options evaluated for the final rule. Sections 6.2 and 6.3 discuss wastewater discharge flow rates and pollutant characteristics for effluent from FGD wastewater treatment systems and for BA transport water, respectively. Section 6.4 presents a summary of the industry-level pollutant loadings and removals estimates for the regulatory options evaluated by EPA.

[37] Sections 5.2.1 and 5.3.1 describe EPA's methodology to account for CCR Part A 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 BA transport water, EPA estimated plant-level pollutant loadings for baseline and each technology option discussed in the preamble. For example, for any plant discharging FGD wastewater, 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 the final 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 BA transport water, 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).

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 BA transport water. EPA evaluated these data sources to identify analytical data that meet EPA's acceptance criteria for inclusion in analyses for characterizing discharges of FGD wastewater and BA transport water. EPA's acceptance criteria for both FGD wastewater and BA 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 BA 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 EPA's analyses.
- Analytical data must represent individual sample results rather than average results representing multiple plants or plant-specific long-term averages. [38]
- Analytical data must not be duplicative of other accepted data.
- Sample analyses must be completed using accepted analytical methods.[39]
- 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, EPA reviewed all FGD wastewater data sets to confirm that the samples were representative of a BAT treatment system collected during typical plant operations.

[38] Where individual sample results and plant-level average sample concentrations were both available for a data set, EPA preferentially used the individual sample results.

[39] EPA's bottom ash transport water analytical data criteria remain unchanged from proposal. 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, 2019b) for a list of EPA's accepted analytical methods.

See “Development Memo for FGD Wastewater Data in the Analytical Database” for more specific details on the acceptance criteria used to generate EPA’s FGD analytical data set (ERG, 2015a).

Data for BA 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, EPA’s additional acceptance criteria specific to BA transport water samples include:

- Sample must be at least 75 percent by volume BA 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.[40]

To ensure analytical data are representative of FGD wastewater or BA transport water, 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 BA transport water, respectively.

For each plant discharging FGD wastewater or BA transport water, 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 BA transport water, and the corresponding contribution from each individual steam electric generating unit. Since EPA now evaluates units in the subcategory permanently ceasing coal combustion by 2028, the Agency adjusted the discharge flow rates used in the pollutant loadings estimates to account for retirements, fuel conversions, and other changes in operations scheduled to occur by December 31, 2023, described in Section 3, that will eliminate or alter the discharge of an applicable wastestream.[41] EPA also updated flows based on public comments on the proposed rule. Finally, the Agency adjusted the discharge flow rates to account for changes in plant operations impacted by the CCR Part A rule. For FGD wastewater, loadings were estimated using the optimized FGD flow rate described in Section 5.2.1; that section also describes how EPA accounted for the CCR Part A rule. Section 5.3.1 describes the development of BA transport water discharge flow rates and how EPA accounted for the CCR Part A rule.

[40] EPA did not accept simulated surface impoundment effluent (i.e., settled ash sluice) 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).

[41] See the memorandum titled “Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule” (ERG, 2020d) 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.

EPA calculated baseline and post-compliance pollutant loadings for each plant discharging FGD wastewater or BA 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.
$\text{Conc}_{\text{pollutant}}$	=	The concentration of a specific pollutant present in the wastestream, in micrograms per liter (µg/L).

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:[42]

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

Equation 6-2

Where:

$\text{Loading}_{\text{baseline}}$	=	The estimated pollutant loadings discharged for a specific pollutant for the baseline technology option, in pounds per year.
$\text{Loading}_{\text{post-compliance}}$	=	The estimated pollutant loadings discharged for a specific pollutant for the post-compliance technology option, in pounds per year.

EPA identified several plants that reported transferring wastewater to a POTW rather than discharging directly to surface water. For these plants, 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. EPA used the following equation to adjust baseline and post-compliance loadings estimates for each pollutant to account for removals achieved by the POTW:

[42] 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

EPA has identified 61 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, 2023. For these plants, 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 final rule, EPA used the analytical data set that was used to characterize pollutant concentrations in FGD wastewater for the 2015 rule. 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. 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 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, EPA found that the effluent quality from membrane filtration is comparable to the effluent quality attained by the thermal evaporation treatment technology. Therefore, 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, EPA also used information for bromine and iodine collected since the 2015 rule to supplement the data sets described above. For baseline and post-compliance technology options, EPA estimated plant-specific bromide and iodine loadings for each plant using a mass balance approach. The mass balance approach estimates the plant-specific bromide and iodine loadings that result from both the naturally-occurring bromine and iodine in the coal being burned and any bromide or iodide additives that are being used for mercury emission control at the plant. EPA used the mass balance approach for bromine and iodine because the use of refined coals and additives can substantially increase the mass of halogens discharged, and the data in the record enabled EPA to evaluate whether specific plants were relying on native coals or using approaches that increase the halogens 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 bromide and iodine discharged by power plants. Additional information on the Agency's methodology for estimating bromide and iodine loadings associated with FGD wastewater discharges is discussed in the memoranda titled "Mass Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants" (ERG, 2020r) and "Mass Balance Approach to Estimating Iodine Loadings from Steam Electric Power Plants" (ERG, 2020s).

Significantly less data are available for estimating iodine loadings than for bromide loadings. In its analysis, EPA relied on 95 data points for estimating native iodine levels in coal compared to more than 4,000 data points for native bromide levels. In addition, less information is available to the public on the rates at which iodine additives are added to coal than for bromide additives. The majority of coal-fired plants use bromide additives at this time, and their use has been the focus of multiple studies of industry practice over the past decade. For iodine, EPA relied on a small number of addition rates reported in publicly available data sources to estimate an average addition rate. Furthermore, EPA was unable to compare iodine loadings estimates to measured concentrations, as the Agency did for bromide loadings, because of the absence of data on iodine levels in coal-fired power plant wastewaters or receiving waters in public data sources. For these reasons, the uncertainty associated with the Agency's iodine loadings estimates is greater than that associated with its bromide loadings estimates.

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
Conventional Pollutants				
Total Suspended Solids (TSS)	27,900	8,590	8,590	2,000
Priority Pollutants				
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
Nonconventional Pollutants				
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 [a]	-	-	-	-
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 – EPA estimated bromide concentrations in FGD wastewater using analytical data provided in response to EPA's January 2018 data request, as discussed in the memorandum titled "Characterization of Bromide Concentrations in FGD Wastewater" (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). EPA received no data on iodine concentration in FGD wastewater.

6.2.2 FGD Wastewater Flows

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, EPA calculated plant-specific FGD purge flow rates and optimized FGD flow rates to estimate compliance costs for each of the 61 coal-fired power plants discharging FGD wastewater. To be consistent with EPA's methodology for estimated plant-level O&M compliance costs, EPA used plant-specific optimized FGD flow rates to estimate baseline and post-compliance loadings.

6.2.3 Baseline and Technology Option Loadings

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, 2020h). As discussed in Section 6.1, 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.[43] 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, EPA assumed the following:

Baseline Loadings (CP+HRTR):

- 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. EPA assumes that these plants would install a CP+HRTR system to comply with effluent standards and limitations established under the 2015 rule.
- 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,[44] 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 avoids potential for noncompliance), EPA determined that it is reasonable to assume plants will choose to reuse the treated effluent within the FGD scrubber system.

[43] EPA adjusted loadings for plants discharging to a POTW to account for additional removals that will take place at the POTW.

[44] For example, mist eliminator wash water or limestone slurry preparation.

<u>Chemical Precipitation:</u>

- 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.
- 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.

<u>CP+LRTR:</u>

- 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.

<u>Membrane Filtration:</u>

- 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 management 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.[45] Plants currently treating their FGD wastewater with an evaporation system will continue doing so; thus, their loadings remain unchanged from baseline.

EPA identified one plant transferring FGD wastewater to a POTW. EPA expects that this plant will continue to transfer the wastewater to a POTW for all technology options other than

[45] 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, EPA determined that it is reasonable to assume plants will choose to reuse the treated effluent within the FGD scrubber system.

membrane filtration. Therefore, 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 EPA's method for estimating annual pollutant loadings and removals for steam electric power plants that discharge BA transport water and are not expected to retire or convert fuel sources by December 31, 2023. EPA identified 81 coal-fired power plants that operate wet bottom ash handling systems and discharge the BA 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, 2023. For these plants, EPA estimated pollutant loadings for baseline conditions (based on closed-loop bottom ash system that complies with a baseline standard) and for the two technology options evaluated as the basis for BA 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 BA 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 BA 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 final rule, the analytical data set EPA used to characterize pollutant concentrations in BA transport water remained unchanged from the 2019 proposed rule. EPA's data sources, acceptance criteria, and development of the analytical data set used to characterize BA transport water are described 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, 2019b).

EPA used the BA transport water analytical data set to calculate an industry average concentration for each pollutant present in the BA transport water using the same methodology as the 2015 rule, described in Section 10 of the 2015 TDD.[46] Table 6-2 presents the average effluent concentrations for pollutants present in BA transport water.

[46] 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, 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
Conventional Pollutants		
Chemical Oxygen Demand (COD)	µg/L	20,800
Total Suspended Solids (TSS)	µg/L	13,400
Priority Pollutants		
Antimony	µg/L	17.3
Arsenic	µg/L	9.32
Cadmium	µg/L	0.721
Chromium	µg/L	5.08
Copper	µg/L	3.95
Lead	µg/L	10.4
Mercury	µg/L	0.102
Nickel	µg/L	17.5
Selenium	µg/L	12.3
Thallium	µg/L	1.13
Zinc	µg/L	33.8
Nonconventional Pollutants [a]		
Aluminum	µg/L	854
Barium	µg/L	106
Boron	µg/L	5,310
Bromide	µg/L	5,100
Calcium	µg/L	154,000
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

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

Pollutant	Unit	Average Concentration
Total Kjeldahl Nitrogen (TKN)	µg/L	968
Vanadium	µg/L	10.1

Source: U.S. EPA, 2015; ERG, 2020a.

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

a – EPA identified ammonia (as N) as a pollutant present in BA transport water; however, EPA excluded this parameter from the calculation of pollutant loadings to avoid double-counting of nitrogen compounds. EPA received no data on iodine in BA transport water.

6.3.2 Bottom Ash Transport Water Flows

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

For baseline conditions, EPA estimated BA transport water flow rates as zero for EGUs subject to the BAT/PSES effluent limitations requiring zero discharge of BA transport water. For EGUs for which the zero discharge standard does not apply (i.e., EGUs with nameplate capacity equal to 50 megawatts (MW) or less), EPA used information from the Steam Electric Survey to calculate a normalized BA 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 BA transport water, EPA estimated the post-compliance BA 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), EPA estimated a purge volume for each plant. EPA calculated BA 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 BA transport water flow rate used to estimate post-compliance pollutant removals is based on the lowest cost control technology selected for each plant.[47]

For the high recycle rate/BMP plan technology option, EPA estimated BA 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, EPA assumed that the plant will continue to discharge BA transport water consistent with current operations. EPA used information from the Steam Electric Survey to calculate a normalized BA transport water discharge flow rate consistent with the methodology described in Section 10.3.2 of the 2015 TDD.

6.3.3 <u>Baseline and Technology Option Loadings</u>

EPA estimated EGU-specific loadings for baseline discharges and each post-compliance technology option considered for control of see the Bottom Ash Transport Water Pollutant Loadings Database (ERG, 2020a). To calculate the mass of pollutants discharged from each plant, EPA multiplied the average concentration of each pollutant in Table 6-2 with the EGU-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, EPA then calculated the baseline and post-compliance loadings for each plant as the sum of pollutant loadings for all EGUs and at the industry level for each evaluated technology option.

Based on Steam Electric Survey data, seven plants in the current population operate their wet-sluicing 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 BA transport water; however, the plants did not use these outfalls for emergency discharges from the closed-loop recycle process. As described in Section 5.3.5, 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 BA transport water. As a result, EPA's analysis assumes that there are no baseline pollutant loadings or post compliance pollutant removals for these plants.

EPA identified one plant transferring BA transport water to a POTW. For this plant, 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, EPA evaluated regulatory options comprising various combinations of technology options to control FGD wastewater and BA transport water. EPA estimated the pollutant loadings for baseline and each regulatory option, as well as removals

[47] As described in Section 5.3, EPA estimated costs associated with converting to both an MDS and remote MDS with a purge, and then selected the most affordable technologically available system for each plant. However, for instances where the MDS is the lowest cost approach for an EGU but 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 EGU will install the remote MDS.

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 EPA. This section also presents the aggregated industry-level loadings and removals for each wastestream and regulatory option.

EPA applied different effluent limitations to steam electric EGUs with a specific steam electric power generating capacity, EGUs with a specific net power generation, and “high-flow” FGD wastewater plants. In calculating the pollutant loadings estimates for each regulatory option, 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.[48] For example, for all regulatory options EPA applied different effluent limitations for EGUs with a capacity of 50 MW or less. In this case, the plant will not face more stringent standards and limitations 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 regulatory options evaluated by EPA.

In order to estimate the total industry pollutant loadings and removals for each regulatory option (accounting for subcategories), EPA first estimated plant-level FGD wastewater and BA transport water pollutant loadings based on the technology bases selected for each plant. EPA then estimated pollutant loadings for each EGU by applying an EGU flow fraction to the flow rates calculated for each plant. See the “FGD 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, 2020a and 2020g).

Table 6-3 and Table 6-4 present the total industry pollutant loadings and removals for FGD wastewater and BA 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 regulatory option. Pollutant loadings and removals are presented in pounds per year and account for the CCR Part A rule. Pollutant loadings and removals presented in these tables are calculated as the sum of TDS and TSS. 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, 2020p). Pollutant loadings represent loadings once all plants and EGUs achieve compliance with the regulatory option presented. Values presented in this document do not account for the timing or exact date of implementation (e.g., when treatment systems are installed by the industry).

[48] For Regulatory Option A and Regulatory Option B, EPA considered whether each plant’s annualized cost for the VIP technology basis (membrane filtration) is less than the annualized cost for CP + LRTR. Where the annualized cost for membrane filtration is less than the other regulatory options, EPA assumed the plant will install membrane treatment and estimated zero post-compliance loadings.

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

Regulatory Option [a]	Estimated Total Industry Loadings (lb/year)	Estimated Change in Total Industry Loadings (lb/year) [a]
Baseline	1,530,000,000	-
A	1,500,000,000	-26,700,000
B	1,500,000,000	-30,300,000
C	0	-1,530,000,000
D[b]	1,660,000,000	-

Sources: ERG, 2020; U.S. EPA, 2019.

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.

b – Regulatory Option D reflects the population, methodology, and pollutant loadings considered for the 2019 proposed rule (see Section 6.4 of the Proposed TDD (U.S. EPA, 2019)). The removals presented are compared to the 2019 proposed baseline. These values should not be used for direct comparisons to this final rule.

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 Loadings (lb/year)	Estimated Change in Total Industry Loadings (lb/year) [a]
Baseline	31,200	-
A	25,700,000	25,700,000
B	15,600,000	15,600,000
C	15,600,000	15,600,000
D[b]	14,300,000	13,400,000

Sources: ERG, 2020; U.S. EPA, 2019.

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.

b – Regulatory Option D reflects the population, methodology, and pollutant loadings considered for the 2019 proposed rule (see Section 6.4 of the Proposed TDD (U.S. EPA, 2019)). The removals presented are compared to the 2019 proposed baseline. These values should not be used for direct comparisons to this final rule.

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) [a]
Baseline	1,530,000,000	--
A	1,530,000,000	-972,000
B	1,510,000,000	-14,700,000
C	15,600,000	-1,510,000,000
D[b]	1,680,000,000	13,400,000

Source: ERG, 2020; U.S. EPA, 2019.

Note: Pollutant loadings and removals are rounded to three significant figures, so figures do not sum due to independent rounding. For example, the estimated changes in pollutant loadings from baseline for Option A are calculated as 1,528,154,581 lb/year – 1,529,126,625 lb/year, which when rounded to three significant figures becomes 1,530,000,000 – 1,530,000,000 in Table 6-5, but still results in -972,000 lb/year. See the Analyte Level Pollutant Loadings by Regulatory Option memorandum (ERG, 2020) for additional details.

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.

b – Regulatory Option D reflects the population, methodology, and pollutant loadings considered for the 2019 proposed rule (see Section 6.4 of the Proposed TDD (U.S. EPA, 2019)). The removals presented are compared to the 2019 proposed baseline. These values should not be used for direct comparisons to this final rule.

SECTION 7
NON-WATER QUALITY ENVIRONMENTAL IMPACTS

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 EPA to consider non-water-quality environmental impacts (NWQEIs), including energy impacts, associated with effluent limitations guidelines and standards (ELGs). Accordingly, EPA has considered the potential impacts of the regulatory options considered for flue gas desulfurization (FGD) wastewater and BA transport water discharged from steam electric power plants on energy consumption (including fuel usage), air emissions, solid waste generation, and water use. As with the costs discussed in Section 5, the NWQEIs associated with the regulatory options for this rulemaking are the incremental changes in NWQEIs (an increase or decrease) relative to the NWQEIs 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, 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, 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, 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, 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, EPA developed relationships between EGU 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. 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 Revisions to the Steam Electric Effluent Limitations Guidelines and Standards" for additional details (ERG, 2020y).

Similarly, as applicable, EPA also estimated the change in energy use that would result from ceasing wet-sluicing of bottom ash and reduced use of earthmoving equipment in order to comply with the 2015 rule standards and all regulatory options evaluated. EPA estimated electrical energy use from horsepower ratings of wet-sluicing system pumps and the earthmoving equipment engine. EPA estimated energy savings associated with only earthmoving equipment for plants sending FGD solids or bottom ash to surface impoundments.

EPA summed plant-specific energy usage estimates to calculate the net change in energy requirements for the regulatory options considered for the final rule; this information is presented in Table 7-1.

Energy usage also includes the fuel consumption associated with the changes in transportation. These changes include transportation needed to landfill solid waste and combustion residuals (*e.g.*, ash) at steam electric power plants to on-site or off-site landfills using open dump trucks and disposal of concentrated brine from the treatment of an rMDS bottom ash slipstream with an RO system to a centralized waste treatment (CWT) facility using a tanker truck. In general, EPA calculated fuel usage based on the estimated amount of time spent loading and unloading solid waste, combustion residuals, or concentrated brine into 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, combustion residuals, or concentrated brine, and fuel consumption. The frequency and distance of transport to a landfill 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 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, combustion residuals, and concentrated brine (ERG, 2020y). Table 7-1 shows the net change in national annual fuel consumption associated with the regulatory options considered for the final rule and the 2015 baseline.

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

Non-Water-Quality Impact	Net Change in Energy Use Associated with ELG			
	Option A	Option B	Option C	Option D [a]
Electrical Energy Usage (Megawatt Hours)	-37,200	-29,400	167,000	-82,300
Fuel (Gallons Per Year)	-1,062,000	-1,024,000	-786,000	0

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

a – Regulatory Option D reflects the population and methodology considered for the 2019 proposed rule (see Section 7.1 of the Proposed TDD (U.S. EPA, 2019)). These values should not be used for direct comparisons to this final rule.

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 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 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 Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Categor*y for additional discussion of the third mechanism (U.S. EPA, 2020).

Air pollution is generated when fossil fuels burn. Steam electric power plants also generate air emissions from operating vehicles such as dump trucks, tanker 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_2) and nitrogen oxides (NOx). Greenhouse gases are gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) that absorb radiation, thereby trapping heat in the atmosphere, and contributing to a wide range of domestic effects.[49] Conversely, decreasing energy use or less vehicle operation will result in decreased air pollution.

EPA calculated air emissions resulting from the change in power requirements[50] using year-explicit emission factors estimated by the Integrated Planning Model (IPM)[51] for CO_2, NO_x, and SO_2. The IPM output provides estimates of electricity generation and resulting emissions by plant and North American Electric Reliability Corporation (NERC) region. EPA used detailed outputs for the 2030 IPM run year to estimated 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.

[49] EPA did not specifically evaluate nitrous oxide emissions as part of the NWQEI analysis. To avoid double counting air emission estimates, EPA calculated only nitrogen oxide emissions, which would include nitrous oxide emissions.

[50] 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.

[51] 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 EPA to analyze the estimated impact of environmental policies on the U.S. power sector.

EPA calculated NO_X, CO_2, and SO_2 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.

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.[52]

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, EPA used NERC-average emission factors instead of plant-specific emissions factors.

Because, for the final rule, EPA ran IPM for Regulatory Option A only, EPA used IPM emission factors calculated for Regulatory Option A to estimate changes in power requirements air emissions for Regulatory Options B and C.

To estimate air emissions associated with operation of transport vehicles, EPA used the MOVES2014b model to generate air emission factors for NOx, SO_2, CO_2, and CH_4. 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, 2018). 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, Long-haul Trucks Operating in 2018

Roadway Type	NO_X (ton/mi)	SO_2 (ton/mi)	CO_2 (ton/mi)	CH_4 (ton/mi)
Highway (restricted access)	1.75E-06	1.59E-08	0.0019	4.22E-08
Local (unrestricted access)	2.00E-06	1.73E-08	0.0021	6.55E-08

Source: U.S. EPA, 2018. MOVES2014 (database version movesdb20181203).

Vehicle types: Single and combination unit long-haul trucks.

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 and concentrated brine to a CWT.

[52] Emission factors are calculated as plant-level emissions divided by plant-level generation.

EPA estimated the annual number of miles that dump trucks moving ash or wastewater treatment solids to on- or off-site landfills or tanker trucks transporting concentrated brine to CWTs would travel to comply with limitations associated with the regulatory options. See EPA's memorandum "Non-Water Quality Environmental Impacts for 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, 2020y). 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 A	Option B	Option C	Option D [a]
NO_X (tons/year)	-21.9	-20.9	71.7	-49.3
SO_X (tons/year)	-16.8	-15.1	62.9	-81.9
CO_2 (metric tons/year)	-30,200	-27,500	156,000	-66,500
CH_4 (tons/year)	-0.217	-0.217	-0.17	0

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

a – Regulatory Option D reflects the population and methodology considered for the 2019 proposed rule (see Section 7.2 of the Proposed TDD (U.S. EPA, 2019)). These values should not be used for direct comparisons to the final rule.

EPA estimated the change in the profile of electricity generation under Regulatory Option A using IPM. IPM predicts changes in electricity generation across all electricity EGUs, including those at plants to which the ELGs apply and which see changes in compliance costs under the regulatory options. 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 final rule, compared to baseline, are shown in Table 7-4.

Table 7-4. Net Change in Industry-Level Air Emissions for Regulatory Option A

Non-Water Quality Impact	Net Change in Air Emissions Associated with the ELG
NO_x (tons/year)	670
SO_x (tons/year)	1,600
CO_2 (metric tons/year)	2,420,000
CH_4 (tons/year)	-0.217

Note: Negative values represent a decrease in air emissions compared to baseline. Positive values represent an increase in air emissions compared to 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). 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 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 regulatory options are comparable to the baseline. See EPA's memorandum "Non-Water Quality Environmental Impacts for Revisions to the Steam Electric Effluent Limitations Guidelines and Standards" for the specific calculations of solids generated (ERG, 2020y). 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 A	Option B	Option C	Option D [a]
Solids (tons/year)	30,800	37,200	2,700,000	-1.66

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.

a – Regulatory Option D reflects the population and methodology considered for the 2019 proposed rule (see Section 7.3 of the Proposed TDD (U.S. EPA, 2019)). These values should not be used for direct comparisons to this final rule.

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 BA transport water will eliminate or reduce water use associated with wet ash sluicing operating systems. Baseline required zero discharge of BA transport water; therefore, EPA estimated an increase in water use associated with all regulatory options compared to baseline, due to the purge BA transport water from rMDS under the options. 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 B and C are expected to experience a decrease in water use compared to baseline because EPA assumes they will reuse the membrane permeate in the FGD scrubber. 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 A	Option B	Option C	Option D [a]
Water Reduction (MGD)	3.94	4.49	-9.93	3.37

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

a – Regulatory Option D reflects the population and methodology considered for the 2019 proposed rule (see Section 7.4 of the Proposed TDD (U.S. EPA, 2019)). These values should not be used for direct comparisons to this final rule.

SECTION 8
EFFLUENT LIMITATIONS

This section describes the pollutants selected for regulation for each wastestream evaluated as part of this reconsideration and the methodology used to calculate the final effluent limitations and standards. This section also describes the method for determining the allowable purge volume for discharges of bottom ash (BA) transport water from steam electric power plants operating recirculating bottom ash handling systems. As used in this section, *regulated pollutants* are pollutants for which EPA established numerical effluent limitations and standards in the final rule.

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 is 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.

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

- 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.
- 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).
- 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.[53]

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 or indirect).

[53] EPA received public comment suggesting it should have considered regulating iodine as part of this rulemaking; however, none of the pilot studies referenced in this TDD collected data on iodine and there is no EPA-approved test method for iodine. Although the data quality and quantity on iodine in FGD and BAT wastestreams is insufficient for EPA to consider it for regulation, iodine and bromine are both halogens. The treatment techniques for removal of bromide (membrane, electrochemical and adsorptive techniques) remove comparable levels of iodides (Watson, 2012). Furthermore, these same treatment techniques are used to remove total dissolved solids (TDS). EPA concludes that bromides and TDS are appropriate indicator pollutants for iodine.

8.1.1 **Direct Dischargers**

As described in the preamble, the final rule establishes the best available control technology economically feasible (BAT)[54] limitations for the discharge of flue gas desulfurization (FGD) wastewater based on three[55] different treatment technologies, which apply differently depending on whether a plant qualifies for a subcategory established by the rule (i.e., low utilization EGUs and high flow plants) or whether a plant opts into the voluntary incentives program (VIP). The pollutants considered for regulation by each treatment technology are discussed below.

Chemical Precipitation

EPA is establishing BAT limitations for two pollutants (arsenic and mercury) based on treatment with chemical precipitation that apply to two subcategories. 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 based on chemical precipitation is described below:

- *Conventional Pollutants.* EPA identified total suspended solids (TSS) as a pollutant present in FGD wastewater. The existing best practicable control technology (BPT) limitations adequately control TSS in discharges of FGD wastewater.
- *Treatment Chemicals.* EPA identified four pollutants present in FGD wastewater but did not establish chemical precipitation-based limits for them because they often are used as treatment chemicals in chemical precipitation systems: aluminum, calcium, iron, and sodium.
- *Pollutants Not Effectively Treated.* EPA identified 10 pollutants which are not reliably removed by chemical precipitation and therefore did not establish chemical precipitation-based limits for them. These pollutants are ammonia, boron, bromide, chloride, cyanide, nitrate/nitrite as N, phosphorus, selenium, and total dissolved solids (TDS).[56]
- *Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants*. The remaining pollutants EPA identified in FGD wastestreams 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 a specific pH to enhance removal of specific metals. Most metals are precipitated to some

[54] For some plants, the final rule establishes BAT limitations equal to the best practicable control technology (BPT) limitations established in the 2015 rule. The 2015 rule BPT limitations are not being revised.

[55] This does not include the treatment technology of surface impoundments, because the 2015 rule BPT limitations are based on the surface impoundments technology.

[56] 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, EPA has determined that the chemical precipitation system is not demonstrated to reliably treat these pollutants.

degree in the chemical precipitation system, thereby resulting in the removal of a wide range of metals. EPA's design basis for the chemical precipitation system includes both hydroxide and sulfide precipitation, as well as iron co-precipitation. Therefore, for the chemical precipitation technology basis, 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			✓
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			✓

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
Total Dissolved Solids		✓	
Vanadium			✓
Zinc			✓

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

EPA is establishing 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 based on CP+LRTR is described below:

- *Conventional Pollutants.* EPA identified TSS as a pollutant present in FGD wastewater. The existing BPT limitations adequately control TSS in discharges of FGD wastewater.
- *Treatment Chemicals.* EPA identified five pollutants present in FGD wastewater, but did not establish CP+LRTR-based limits for them because they are often used as treatment chemicals in CP+LRTR systems: aluminum, calcium, iron, phosphorus, and sodium.
- *Pollutants Not Effectively Treated.* EPA identified seven pollutants which are not reliably removed by CP+LRTR and therefore did not establish CP+LRTR limits for them. These pollutants are: ammonia, boron, bromide, chloride, cyanide, and TDS.
- *Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants.* The remaining pollutants EPA identified in FGD wastestreams 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. Therefore, 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. Therefore, for the CP + LRTR technology basis, EPA selected both of these pollutants, in addition to arsenic and mercury as regulated pollutants.

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			✓
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

EPA is establishing BAT limitations for six pollutants (arsenic, mercury, selenium, nitrate/nitrite as N, bromide, and TDS) based on treatment with membrane filtration that apply to the VIP. 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 based on membrane filtration is described below:

- *Conventional Pollutants.* 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 process knowledge and performance data for membrane filtration systems, all pollutants known to be present in FGD wastewater would be effectively treated by membrane filtration. EPA recognizes that some facilities may choose to employ thermal systems to control pollutants in FGD wastewater, and data for thermal systems demonstrate that such systems would be as effective as membrane filtration systems.
- *Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants.* The remaining pollutants EPA identified in FGD wastestreams are metals, metalloids, other nonmetals, nitrate-nitrite as N, chloride, bromide, and TDS. As described in the preamble, the membrane filtration technology evaluated as the technology basis removes pollutants based on their molecular size and solubility. Therefore, for the membrane filtration technology basis, 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			✓

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
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			✓

8.1.2 Indirect Dischargers

As part of establishing pretreatment standards for existing sources (PSES) for a pollutant, EPA examines whether the pollutant "passes through" a publicly owned treatment works (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, 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 performing secondary treatment 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, EPA used data from the 2015 rule to characterize pollutant concentrations in the effluent from all three treatment technologies described above: CP, CP+LRTR, and membrane filtration. As a result, EPA used the results of the 2015 pass-through analysis to determine which pollutants to regulate for indirect dischargers for the final rule.

The data characterizing CP effluent remains unchanged from the 2015 rule; therefore 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. EPA determined that mercury and arsenic passed through POTW secondary treatment ,therefore, EPA 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 EPA applied the pollutant concentrations used to characterize CP+HRTR as estimates for the effluent pollutant concentrations following CP+LRTR. 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 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% [a]	65.8%	Yes	Yes
Mercury	99.9% [a]	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.

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. As described in Section 6.2.1, the overall average effluent quality for membrane filtration and thermal technologies is comparable. Where effluent data for membrane filtration were not available for specific pollutants, EPA used the pollutant concentrations used to characterize thermal technologies as estimates for the effluent pollutant concentrations following membrane filtration. Accordingly, for bromide and nitrate/nitrate as N, EPA used effluent concentrations for thermal technologies from Section 6.2.1 to estimate the BAT removals for bromide and nitrate/nitrite as N following membrane filtration. Table 8-6 presents the current BAT treatment technology removals and POTW removals for FGD wastewater treated using membrane filtration. All six pollutants were determined to pass through POTW secondary treatment, therefore EPA selected all six as regulated pollutants for PSES based on membrane filtration.

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% [a]	1.89% [b]	Yes	Yes
Mercury	99.9%	90.2%	Yes	Yes
TDS [c]	99.9%	0%	Yes	Yes
Nitrate/Nitrite as N	>98.7%	90.0%	Yes	Yes
Selenium	99.2%	34.3%	Yes	Yes

Source: U.S. EPA, 2015a.

a – 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 (ERG, 2019). Based on these average concentrations, EPA calculated a minimum BAT percent removal of 98.3 percent.

b – EPA expects POTWs may achieve some removal of bromide (e.g., entrainment in treatment residuals); therefore, EPA conservatively set POTW percent removal for bromide equal to the POTW percent removal for bromine. Since the median BAT percent removal is very high, even if POTWs removed a moderate level of bromide, there would still be pass through.

c –POTWs have not been shown to effectively remove TDS. For this analysis EPA set POTW percent removal for TDS to zero and assumed this pollutant passes through POTW secondary treatment. Since the median BAT percent removal is very high, even if POTWs removed a moderate level of TDS, there would still be pass through.

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.

This section describes the data sources, data selection, and statistical methodology 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, 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 EPA collected samples (hereinafter referred to as "EPA sampling"); (2) a sampling program during which 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 EPA applied in selecting plants and data to use as the basis for the numeric limitations for FGD wastewater. EPA has used these or similar criteria in developing limitations for other industries. 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. 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, 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 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 wastestream for which 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, EPA often uses a long-term average test (or LTA test) for plants where EPA possesses both influent and effluent data. 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, 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 (i.e., the data must be analyzed with a sufficiently sensitive method). Also, 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, 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, EPA reviews the process or treatment conditions that may have resulted in extreme values (high and low). Consequently, 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.

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, EPA typically excludes such data in developing the limitations.[57]

Similarly, power plant decommissioning periods represent unique operating conditions associated with the permanent shutdown of the power plant, FGD system, and FGD wastewater

[57] 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.

treatment system,[58] and do not represent best available control technology economically achievable (BAT) level of performance for treatment of FGD wastewater at an operating steam electric power plant. Therefore, 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 final limitations for each FGD wastewater technology option. See the preamble for a description of the technology options. For the final rule, EPA developed FGD limitations beyond BPT based on three technology options: chemical precipitation; CP + LRTR; and membrane filtration. In certain instances, the final rule establishes limitations for FGD wastewater that are equal to the previously established BPT limitations for TSS. EPA used no new effluent concentration data to establish these limitations, BPT is not being revised and, therefore, such limitations are not discussed further in this section. The data sources listed below were used to calculate the final 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.* Six data sets from plants operating a pilot[59] treatment system that includes chemical precipitation followed by LRTR anoxic/anaerobic biological treatment (including ultrafiltration polishing) designed to remove selenium and nitrate-nitrite, as well as further removals of arsenic, mercury, and other metals.
- *Membrane Filtration Technology.* Two data sets from plants operating a pilot[60,61] membrane filtration treatment system that includes chemical precipitation

[58] 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.

[59] See Section 4 for further discussion of four U.S. plants with full scale LRTR, but for which EPA does not have performance data.

[60] EPA has not identified any full-scale membrane plants in the U.S. See Section 4 for further discussion.

[61] EPA has identified at least two full-scale plants in other countries with full-scale membrane filtration systems, but EPA does not have performance data. Further, EPA notes that one vendor in China for the membrane technology is no longer in business.

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 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, 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. EPA has no information to indicate that these time periods represent different operating conditions; therefore, 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.[62] For each 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 EPA either excluded or substituted certain data in calculating the limitations.

Data Exclusions

After selecting the model plant(s), EPA applied the data selection criteria described in Section 8.2.1 by evaluating all available data for each model plant. 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[63] in 40 CFR 136 for National Pollutant Discharge Elimination System (NPDES) purposes, and there was data obtained using such EPA approved methods sufficient to calculate limits; (2) the samples were analyzed using a method that was not a sufficiently sensitive analytical method (e.g., 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

[62] When EPA obtains data from multiple sources (such as EPA sampling, CWA 308 sampling, and plant self-monitoring data in this rulemaking) from a plant for the same time period, 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, EPA may analyze the data from each time period separately. In some past effluent guideline rulemakings, EPA analyzed data as if each time period 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 EPA combined all data for the plant into a single data set.

[63] Samples not using an EPA approved method or samples for which there is no EPA approved method generally require sufficient data to document the quality of the analysis. For the final rule, EPA notes that the regulated pollutants have one or more EPA-approved methods and thus the performance of the method and quality of the data was easily documented. Therefore, only data obtained using an EPA-approved method were included.

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, 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.[64] However, there were some instances in which 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 EPA has calculated limitations in previous ELG rulemakings and is intended to avoid establishing an effluent limitation biased toward a lower concentration than plants can reliably demonstrate compliance.[65] After excluding all the necessary data as described above, EPA compared each reported result to a baseline value. Whenever a detected value or sample-specific detection limit was lower than the baseline value, 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 (µg/L) and the laboratory reported a detected value of 3 µg/L, EPA's calculations would treat the sample result as being non-detected with a sample-specific detection limit of 5 µg/L.

EPA used the following baseline values for each pollutant in the development of the effluent limitations for the steam electric rulemaking:

- Arsenic: 2 micrograms/liter (µg/L).
- Mercury: 0.5 nanograms/liter (ng/L).
- Nitrate-nitrite as N: 0.05 milligrams/liter (mg/L).
- Selenium: 5 micrograms/liter (µg/L).
- TDS: 10 milligrams/liter (mg/L)

[64] 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.

[65] 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. EPA does not suggest that the baseline value should be established at a level that 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.

- Bromide: 0.01 milligrams/liter (mg/L).

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.[66] The baseline values for arsenic and selenium are based on the results of MDL studies conducted by well-operated commercial laboratories using 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), 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 EPA wanted to ensure that plants can achieve the effluent limitations established by the rule, EPA calculated and evaluated both 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

EPA used daily values in developing the limitations. In cases with at least two samples per day, 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 EPA sampling, or overlaps between plant self-monitoring and CWA 308 sampling.

When aggregating the data, 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 EPA sampling data or CWA 308 sampling were aggregated).

[66] The baseline values for mercury and nitrate-nitrite as N are equal to the MLs specified in EPA Methods 1631E and 353.2, respectively. The method EPA used to analyze for TDS (Standard Method 2540C) does not explicitly state an MDL or ML. However, 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, EPA used 10 mg/L as the baseline value for TDS. The baseline value for bromide is based on EPA Method 300.0.

Aggregation of Field Duplicates

During EPA sampling, 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, 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, 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 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 EPA sampling or CWA 308 sampling. When these overlaps occurred, 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), 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, 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). 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, 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 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 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, 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, 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[67] 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 plant 4060 in the membrane data sets.

[67] In section 8.2.3, the plant names associated with EPA sampling episodes are provided. In this section, the pilot plant effluent data are CBI. In order to make the data exclusions available in this document, EPA used plant codes in lieu of plant names.

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 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

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.[68] 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, 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 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.

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

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 99th percentile of the distribution

[68] 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.

of the *daily* measurements. The monthly average limitation is an estimate of the 95th percentile of the distribution of the *monthly* averages of the daily measurements.

EPA uses the 99th and 95th 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 EPA has incorporated an appropriate allowance for variability in the limitations.

EPA's methodology for establishing effluent limitations based on certain percentiles of the statistical distributions may give the impression that EPA expects occasional exceedances of the limitations. This conclusion is incorrect. 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, 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, 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, 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. 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. 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

EPA calculated the limitations by multiplying the long-term average by the appropriate variability factors. In deriving the limitations for a pollutant, 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, 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. 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, 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 final 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

EPA calculated the technology option long-term average for a pollutant in two steps. First, 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 EPA used to estimate the plant-specific long-term average.

Second, 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^{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 $n/2^{th}$ and $[(n/2)+1]^{th}$ 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, 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^{th} 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^{th}

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, 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, 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, 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, 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, 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, EPA transferred the autocorrelation estimates from that treatment technology. Otherwise, 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 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 technology basis for FGD wastewater, 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 CP + LRTR technology basis for FGD wastewater, 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, 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 calculations for arsenic, mercury, nitrate-nitrite as N and selenium for the LRTR treatment option.

For the membrane filtration technology basis for FGD, 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, EPA set the autocorrelation to zero in the calculation of the limitations. EPA did so because there were not sufficient data to reliably evaluate the autocorrelation, nor did 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	Baseline[c]	Correlation Value Used to Calculate Limitation
CP+LRTR	Arsenic [b]	0 or 2 µg/L	0.53
	Mercury	0 or 0.5 ng/L	0.53
	Selenium	0 µg/L	0.65
		5 µg/L	0.64
	Nitrate-nitrite as N [a]	0 mg/L	0.65
		0.05 mg/L	0.64
Chemical Precipitation	Arsenic	0 or 2 µg/L	0.86
	Mercury	0 or 0.5 ng/L	0.89

a – There were not enough detected values for nitrate-nitrite as N, so EPA was not able to directly calculate the autocorrelation. However, 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 EPA was not able to directly calculate the autocorrelation. However, 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.

c – Baseline value of 0 indicates no adjustment for baseline.

8.2.7 Long-Term Averages and Effluent Limitations for FGD Wastewater

Table 8-9 presents the final effluent limitations for discharges of FGD wastewater. As described in Section 8.2.2, 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 final rule use the higher limitation of the two as the result. This same procedure is used for selenium and nitrate-nitrite as N for CP+LRTR treatment technology, except there is a unique correlation value specific to each corresponding baseline (see Table 8-8). 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, 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[a]	Arsenic (µg/L)	4.98	18	8
	Mercury (ng/L)	13.48	103	34
	Nitrate-nitrite as N (mg/L)	2.14	3.7	2.6
	Selenium (µg/L)	15.87	70	29
Membrane Filtration (VIP)	Arsenic (µg/L)	5.0 [b]	5 [c]	--- [d]
	Mercury (ng/L)	5.44	23	10
	Nitrate-nitrite as N (mg/L)	0.89	2.0	1.2
	Selenium (µg/L)	7.35	10[c]	--- [d]
	Bromide (mg/L)	0.200	0.2	--- [d]
	TDS (mg/L)	86.06	306	149
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 plants, low utilization EGUs, or those units ceasing coal combustion by 2028.
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 highest quantitation limit for the evaluated data set(s).
d – 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. The final rule includes an allowance for purges in certain circumstances but imposes a ceiling on the allowable volume of discharge. Therefore, the final rule significantly reduces the discharge of all pollutants in bottom ash transport water. Accordingly, selection of specific pollutants is not necessary.

8.4 EFFLUENT LIMITATIONS FOR BOTTOM ASH TRANSPORT WATER

As described in the preamble, the final rule includes a pollutant discharge allowance in the form of a maximum percentage purge rate for bottom ash transport water. To develop this allowance, 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.

Specifically, EPA reviewed at 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 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 purge rate, EPA reviewed hypothetical maximum discharge volumes and the estimated frequency associated with such infrequent events for wet bottom ash systems (EPRI, 2018).[69]

To estimate the allowance percentage associated with such infrequent events, 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, 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. 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[a]

Infrequent Discharge Needs		**Regular Discharge For Purpose of Adjusting Water Chemistry and/or Water Balance**						
Type of Infrequent Discharge Event	30-Day Average	Plant A	Plant B	Plant C	Plant D	Plant E	Plant F-System1	Plant F-System2
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.

The final rule establishes that BAT effluent limitations and standards on any wastewater purged from a high recycle rate system (capped at a maximum of 10 percent of the total system volume) will be determined on a case-by-case basis by the permitting authority, based on best professional judgement.(BPJ).

[69] EPA did not consider events such as pipe leaks, as these would not be reflective of proper system operation.

SECTION 9
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