United States
Environmental Protection
Agency

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

April 2024

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U.S. Environmental Protection Agency
Office of Water (4303T)
1200 Pennsylvania Avenue, NW
Washington, DC 20460

EPA-821-R-24-004

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List of Abbreviations

ACE	Affordable Clean Energy
BA	bottom ash
BAT	best available technology economically achievable
BCA	Benefit and Cost Analysis
BMP	best management practice
BOD	biochemical oxygen demand
CA	combined ash
CAA	Clean Air Act
CBI	confidential business information
CCR	coal combustion residuals
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CP	chemical precipitation
CPP	Clean Power Plan
CRL	combustion residual leachate
CSAPR	Cross-State Air Pollution Rule
CSC	compact submerged conveyor
CUR	capacity utilization rates
CWA	Clean Water Act
CWT	centralized waste treatment
DOE	Department of Energy
EA	Environmental Assessment

EDR	electrodialysis reversal
EGU	electric generating unit
EIA	Energy Information Administration
EJA	Environmental Justice Analysis
ELGs	effluent limitations guidelines and standards
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FA	fly ash
FBR	fluidized bed reactor
FGD	flue gas desulfurization
FGMC	flue gas mercury control
FO	forward osmosis
gal	gallon
GHG	greenhouse gas
GPD	gallons per day
GPM	gallons per minute
HAP	hazardous air pollutant
HRR	high recycle rate
HRT	hydraulic residence time
HRTR	high residence time reduction
HVAC	heating, ventilation, and air conditioning
ICR	information collection request
IPM	Integrated Planning Model
kWh	kilowatt-hour
L	liter
lb	pound
LRTR	low residence time reduction
LUEGU	low utilization electric generating unit
MATS	Mercury and Air Toxics Standards

MDS	mechanical drag system
mg	milligrams
MGD	million gallons per day
MGY	million gallons per year
mi	mile
µg	micrograms
MW	megawatts
MWh	megawatt-hours
N_2O	nitrous oxide
NA	not applicable
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOPP	notice of planned participation
NO_X	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
NWQEI	non-water quality environmental impacts
O&M	operation and maintenance
OLEM	Office of Land and Emergency Management
ORCR	Office of Resource Conservation and Recovery
PM	particulate matter
POTW	publicly owned treatment works
PSES	pretreatment standards for existing sources
PSNS	pretreatment standards for new sources
QA	quality assurance
QC	quality control
RCRA	Resource Conservation and Recovery Act
RIA	Regulatory Impact Analysis
RO	reverse osmosis

SDE	spray dryer evaporator
SO_2	sulfur dioxide
TCLP	toxicity characteristic leaching procedure
TDD	Technical Development Document
TDS	total dissolved solids
TMT	trimercapto-s-triazine
TPY	tons per year
TSS	total suspended solids
VIP	Voluntary Incentives Program
WOTUS	Waters of the United States
ZVI	zero valent iron

1. Background

This Technical Development Document describes background information for the U.S. Environmental Protection Agency's (EPA's) 2024 final supplemental rulemaking (2024 final rule) for the steam electric power generating point source category. This final rulemaking is based on a review of the effluent limitations guidelines and standards (ELGs) promulgated in 2020 (referred to as the 2020 rule) under Executive Order 13990.

The EPA is finalizing revisions to the 2020 rule based on a review of publicly available data, additional data collected from the steam electric power generating industry, and comments on the 2023 proposed rulemaking. The revisions cover best available technology economically achievable (BAT) and pretreatment standards for existing sources (PSES) requirements for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, combustion residual leachate (CRL), and legacy wastewater from steam electric power plants; and new source performance standards (NSPS) and pretreatment standards for new sources (PSNS) for CRL from steam electric power plants. This document presents information for the revisions including details on EPA's data collection, industry profile updates (*e.g.,* retirements and treatment technology updates), methodologies for estimating costs, pollutant removals, and non-water quality environmental impacts.

In addition to this report, other supporting reports include:

- *Environmental Assessment for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EA), Document No. EPA-821-R-24-005. This report summarizes the potential environmental and human health impacts that are estimated to result from implementation of the revisions to the 2015 and 2020 rules.
- *Benefit and Cost Analysis for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA), Document No. EPA-821-R-24-006. This report summarizes estimated societal benefits and costs that are estimated to result from implementation of the revisions to the 2015 and 2020 rules.
- *Regulatory Impact Analysis for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA), Document No. EPA-821-R-24-007. This report presents a profile of the steam electric power generating industry, a summary of estimated costs and impacts associated with the proposed revisions to the 2015 and 2020 rules, and an assessment of the potential impacts on employment and small businesses.
- *Environmental Justice Analysis for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EJA), Document No. EPA-821-R-24-008. This report presents a profile of the communities and populations potentially impacted by the 2024 final rule, analysis of the distribution of impacts in the baseline and changes, and summary of input from potentially impacted communities that the EPA met with prior to the final rule.

The ELGs for the steam electric power generating category are based on data generated or obtained in accordance with the EPA's Quality Policy and Information Quality Guidelines. The EPA's quality assurance (QA) and quality control (QC) activities for this rulemaking include developing, approving, and implementing quality assurance project plans for the use of environmental data generated or collected from sampling and analyses, existing databases, and literature searches, and for developing any models that use environmental data.

1.1 Legal Authority

The EPA is 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.

Congress passed the Federal Water Pollution Control Act Amendments of 1972, also known as the Clean Water Act (CWA), to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters," per 33 U.S.C. 1251(a). The CWA establishes a comprehensive program for protecting the nation's waters. Among its core provisions, the CWA prohibits the discharge of pollutants from a point source to waters of the United States except as authorized under the CWA. Under section 402 of the CWA, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA also authorizes the EPA to establish national ELGs for discharges from categories of point sources. Refer to the CWA for more information on these limitations, which could affect direct dischargers and indirect dischargers. These final revisions relate primarily to the standards for BAT and to PSES.

1.2 Regulatory History

The EPA first issued a steam electric ELG in 1974, with subsequent revisions in 1977 and 1982. These limitations and standards included requirements on once-through cooling water, cooling tower blowdown, fly ash (FA) transport water, BA transport water, metal cleaning waste, coal pile runoff, and low-volume waste sources. Requirements do not apply to discharges from generating units that primarily use nonfossil or nonnuclear fuel sources (*e.g.,* wood waste, municipal solid waste).

In 2015, the EPA finalized new requirements for multiple wastestreams generated by new and existing steam electric power plants: BA transport water, CRL, FGD wastewater, flue gas mercury control wastewater, FA transport water, and gasification wastewater. Seven petitions for review of the 2015 rule were filed in various circuit courts by industry members, environmental groups, and drinking water utilities. In April 2017, in response to petitions from Utility Water Act Group and the Small Business Administration, the EPA postponed compliance dates for the 2015 rule through administrative action. The EPA later issued a rule, following public notice and an opportunity to comment, postponing the earliest dates for compliance with BAT limitations and PSES on FGD wastewater and BA transport water in the 2015 rule.

On August 11, 2017, the EPA Administrator announced a decision to review and revise BAT requirements for FGD wastewater and BA transport water. The Fifth Circuit Court of Appeals granted the EPA's request to sever and hold in abeyance aspects of litigation related to those two wastestreams. The Fifth Circuit Court of Appeals continued to hear litigation related to legacy wastewater and CRL. In a decision on April 12, 2019, the court vacated limitations on both legacy wastewater and CRL as arbitrary and capricious under the Administrative Procedure Act and unlawful under the CWA. *Southwestern Electric Power Co., et al.* v. *EPA*, 920 F.3d 999 (5th Cir. 2019).

On August 31, 2020, the EPA finalized a rule for the steam electric power generating category that established revised effluent limitations and standards for FGD wastewater and BA transport water. This 2020 rule revised the BAT technology basis for FGD wastewater and BA transport water, established new compliance dates, revised the FGD Voluntary Incentives Program (VIP), and established additional subcategories. See the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001) for details related to the 2020 rule.

On March 29, 2023, the EPA finalized a direct final action to extend the date for existing steam electric power plants to submit a notice of planned participation (NOPP) for the permanent cessation of coal combustion by December 31, 2028 subcategory in the 2020 Steam Electric Reconsideration Rule. The EPA extended the NOPP date in 40 CFR 423.19(f) to June 27, 2023.

1.3 Other Key Regulatory Actions Affecting Steam Electric Power Generating

Multiple EPA offices are taking actions to reduce emissions, discharges, and other environmental impacts associated with steam electric power plants. The EPA made every effort to appropriately account for other rules affecting the industry in its analysis for the 2024 rule. This section provides a brief overview of recent changes to the regulatory requirements for steam electric power plants.

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

  These regulations established requirements for the management and disposal of coal ash, including requirements designed to prevent leaking of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. The 2015 CCR rule also set recordkeeping and reporting requirements, as well as requirements for each plant to establish and post specific information to a publicly accessible website. The rule also established requirements to distinguish the beneficial use of CCR from disposal.

  As a result of the D.C. Circuit Court decisions in *Utility Solid Waste Activities Group v. EPA*, 901 F.3d 414 (D.C. Cir. 2018) ("*USWAG* decision" or "*USWAG*"), and *Waterkeeper Alliance Inc. et al. v. EPA*, No. 18-1289 (D.C. Cir. filed March 13, 2019), the Administrator signed two rules: *A Holistic Approach to Closure Part A: Deadline to Initiate Closure and Enhancing Public Access to Information* (CCR Part A rule) on July 29, 2020, and *A Holistic Approach to Closure Part B: Alternate Liner Demonstration* (CCR Part B rule) on October 15, 2020. The EPA finalized five amendments to the 2015 CCR rule which are relevant to the management of the wastewaters covered by this ELG because these wastewaters have historically been co-managed with CCR in the same surface impoundments. First, the CCR Part A rule established a new deadline of April 11, 2021, for all unlined surface impoundments in which CCR are managed ("CCR surface impoundments"), as well as CCR surface impoundments that failed the location restriction for placement above the uppermost aquifer, to stop receiving waste and begin closure or retrofitting. The EPA established this date after evaluating the steps that owners and operators need to take for CCR surface impoundments to stop receiving waste and begin closure, and the timeframes needed for implementation. (This did not affect the ability of plants to install new, composite-lined CCR surface impoundments.) Second, the Part A rule established procedures for plants to obtain approval from the EPA for additional time to develop alternative disposal capacity to manage their wastestreams (both CCR and non-CCR) before they must stop receiving waste and begin closing their CCR surface impoundments. Third, the Part A rule changed the classification of compacted-soil-lined and clay-lined surface impoundments from lined to unlined. Fourth, the Part B rule finalized procedures potentially allowing a limited number of facilities to demonstrate to the EPA that, based on groundwater data and the design of a particular surface impoundment, the unit ensures there is no reasonable probability of adverse effects to human health and the environment. Should the EPA approve such a submission, these CCR surface impoundments would be allowed to continue to operate.

  As explained in the 2015 and 2020 ELG rules, the ELGs and CCR rules may affect the same EGU or activity at a plant. Therefore, when the EPA finalized the ELG and CCR rules in 2015, and revisions to both rules in 2020, the Agency coordinated the ELG and CCR rules to minimize the complexity of implementing engineering, financial, and permitting activities. Likewise, the EPA considered the interaction of the two rules during the development of this final rule. The EPA's analytic baseline includes the final requirements of these rules using the most recent data provided under the CCR rule reporting and recordkeeping requirements. This is further described in Supplemental TDD, Section 3. For more information on the CCR Part A and Part B rules, including information about their ongoing implementation, visit *www.epa.gov/coalash/coal-ash-rule*.

  Concurrently with the final ELG, in a separate rulemaking, the EPA is also finalizing regulatory requirements for inactive CCR surface impoundments at inactive utilities ("legacy CCR surface impoundment" or "legacy impoundment"). This action is being taken in response to the August 21, 2018, opinion by the U.S. Court of Appeals for the District of Columbia Circuit in the *USWAG* decision that vacated and remanded the provision exempting legacy impoundments from the CCR regulations. This action includes adding a definition for legacy CCR surface impoundments and other terms relevant to this rulemaking. It also requires that legacy CCR surface impoundments comply with certain existing CCR regulations with tailored compliance deadlines.

The EPA is also establishing requirements to address the risks from currently exempt solid waste management that involves the direct placement of CCR on the land. The EPA is extending a subset of the existing requirements in 40 CFR part 257, subpart D to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR rule, inactive CCR landfills, and other areas where CCR is managed directly on the land. In this action, the EPA refers to these as CCR management units, or CCRMU. This rule will apply to all existing CCR facilities and all inactive facilities with legacy CCR surface impoundments subject to this final rule.

Finally, the EPA is making a number of technical corrections to the existing regulations, such as correcting certain citations and harmonizing definitions. For further information on the CCR regulations, including information about the CCR Part A and Part B rules' ongoing implementation, visit *www.epa.gov/coalash/coal-ash-rule*.

- Air Pollution Rules and Implementation. The EPA is taking several actions to regulate a variety of conventional, hazardous, and greenhouse gas (GHG) air pollutants, including actions to regulate the same steam electric power plants subject to part 423. In light of these ongoing actions, the EPA has worked to consider appropriate flexibilities in this ELG rule to provide certainty to the regulated community while ensuring the statutory objectives of each program are achieved. Furthermore, to the extent that these actions have been published before this rule's signature and are already impacting steam electric power plant operations, the EPA has accounted for these changed operations in its Integrated Planning Model (IPM) modeling discussed in the preamble Section VIII.
- The Revised Cross State Air Pollution Rule Update and the Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards. On June 5, 2023, the EPA promulgated its final Good Neighbor Plan, which secures significant reductions in ozone-forming emissions of nitrogen oxides (NO_X) from power plants and industrial facilities. 88 FR 36654. The Good Neighbor Plan ensures that 23 states meet the Clean Air Act's (CAA's) "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining EPA's health-based air quality standard for ground-level ozone (or "smog"), known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS), in downwind states. Further information on this action is available on the EPA's website.[1]

  As of September 21, 2023, the Good Neighbor Plan's "Group 3" ozone-season NO_X control program for power plants is being implemented in: Illinois, Indiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and Wisconsin. Pursuant to court orders staying the Agency's State Implementation Plan disapproval action in the following states, the EPA is not currently implementing the Good Neighbor Plan "Group 3" ozone-season NO_X control program for power plants in: Alabama, Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and West Virginia.[2]

  On January 16, 2024, the EPA signed a proposal to partially approve and partially disapprove State Implementation Plan submittals addressing interstate transport for the 2015 ozone NAAQS from Arizona, Iowa, Kansas, New Mexico, and Tennessee and proposed to include these states in the Good Neighbor Plan beginning in 2025.

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[1] *See https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.*

[2] Further information on EPA's response to the stay orders can be found online at: *https://www.epa.gov/Cross-State-Air-Pollution/epa-response-judicial-stay-orders.*

On April 30, 2021, the EPA published the final Revised Cross-State Air Pollution Rule (CSAPR) Update, 86 FR 23054, which resolved 21 states' good neighbor obligations for the 2008 ozone NAAQS, following the remand of the 2016 CSAPR Update (81 FR 74504) in *Wisconsin v. EPA*, 938 F.3d 308 (D.C. Cir. 2019). Together, these two rules establish the Group 2 and Group 3 market-based emissions trading programs for 22 states in the eastern United States for emissions of NO_X from fossil fuel-fired EGUs during the summer ozone season.

- Clean Air Act Section 111 Rule. Concurrently with the final ELG, the EPA is finalizing the repeal of the Affordable Clean Energy Rule, establishing Best System of Emissions Reduction (BSER) determinations and emission guidelines for existing fossil fuel-fired EGUs, and establishing BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines and modified fossil fuel-fired EGUs. Specifically, for coal-fired EGUs, the EPA is establishing final standards based on carbon capture and storage/sequestration with 90 percent capture with a compliance date of January 1, 2032. For coal-fired EGUs retiring by January 1, 2039, the EPA is establishing final standards based on 40 percent natural gas co-firing with a compliance date of January 1, 2030.

  While four subcategories for coal-fired EGUs were proposed, the EPA is finalizing just the two subcategories for coal-fired EGUs as described in the preceding paragraph. Consistent with 40 CFR 60.24a(e) and the Agency's explanation in the proposal, states have the ability to consider, *inter alia*, a particular source's remaining useful life when applying a standard of performance to that source.[3]

  In addition, the EPA is creating an option for states to provide for a compliance date extension for existing sources of up to one year under certain circumstances for sources that are installing control technologies to comply with their standards of performance. States may also provide, by inclusion in their state plans, a reliability assurance mechanism of up to one year that under limited circumstances would allow existing EGUs that had planned to cease operating by a certain date to temporarily remain available to support reliability. Any extensions exceeding 1-year must be addressed through a state plan revision. Further information about the CAA section 111 rule is available online at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power*.

- Mercury and Air Toxics Standards Rule. On March 6, 2023, the EPA published a final rule which reaffirmed that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost. This action revoked a 2020 finding that it was not appropriate and necessary to regulate coal- and oil-fired power plants under CAA section 112, which covers toxic air pollutants. The EPA reviewed the 2020 finding and considered updated information on both the public health burden associated with HAP emissions from coal- and oil-fired power plants, as well as the costs associated with reducing those emissions under the Mercury and Air Toxics Standards (MATS). After weighing the public risks these emissions pose to all Americans (and particularly exposed and sensitive populations) against the costs of reducing this harmful pollution, the EPA concluded that it remains appropriate and necessary to regulate these emissions. This action ensures that coal- and oil-fired power plants continue to control emissions of hazardous air pollution and that the Agency properly interprets the CAA to protect the public from hazardous air emissions.

  Concurrently with the final ELG, the EPA is finalizing an update to the National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly known as the Mercury and Air Toxics Standards (MATS) for power plants, to reflect recent developments in control technologies and the performance of these plants. This final rule includes an important set of improvements and updates to MATS and also fulfills the EPA's responsibility under the Clean Air Act to periodically re-evaluate its standards in light of advancements in pollution control technologies to determine whether revisions are necessary. The improvements consist of:

[3] See 88 FR 33383 (invoking RULOF based on a particular coal-fired EGU's remaining useful life "is not prohibited under these emission guidelines").

  - Further limiting the emission of non-mercury HAP metals from existing coal-fired power plants by significantly reducing the emission standard for filterable particulate matter (fPM), which is designed to control non-mercury HAP metals. The EPA is finalizing a two-thirds reduction in the fPM standard;[4]
  - Tightening the emission limit for mercury for existing lignite-fired power plants by 70 percent;[5]
  - Strengthening emissions monitoring and compliance by requiring coal-and oil-fired EGUs to comply with the fPM standard using PM continuous emission monitoring systems (CEMS);[6]
  - Revising the startup requirements in MATS to assure better emissions performance during startup.
  - Additional information on the final MATS is available on the EPA's website.[7]
- National Ambient Air Quality Standards Rules for Particulate Matter. On February 7, 2024, the EPA Administrator signed a final rule strengthening the National Ambient Air Quality Standards for Particulate Matter (PM NAAQS) to protect millions of Americans from harmful and costly health impacts, such as heart attacks and premature death. Particle or soot pollution is one of the most dangerous forms of air pollution, and an extensive body of science links it to a range of serious and in some cases deadly illnesses. The EPA set the level of the primary (health-based) annual particulate matter ($PM_{2.5}$) standard at 9.0 micrograms per cubic meter to provide increased public health protection, consistent with the available health science. The EPA did not change the current primary and secondary (welfare-based) 24-hour $PM_{2.5}$ standards, the secondary annual $PM_{2.5}$ standard, and the primary and secondary PM10 standards. The EPA also revised the Air Quality Index to improve public communications about the risks from $PM_{2.5}$ exposures and made changes to the monitoring network to enhance protection of air quality in communities overburdened by air pollution. More information about this action is available on the EPA's website.[8]

[4] Also, the EPA is finalizing the removal of the low-emitting EGU provisions for fPM and non-mercury HAP metals.

[5] This level aligns with the mercury standard that other coal-fired power plants have been achieving under the current MATS.

[6] PM CEMS provide regulators, the public, and facility owners or operators with cost-effective, accurate, and continuous emission measurements. This real-time, quality-assured feedback can lead to improved control device and power plant operation, which will reduce air pollutant emissions and exposure for local communities.

[7] *See https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.*

[8] *See https://www.epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm*.

2. Data Collection Activities

The U.S. Environmental Protection Agency (EPA) collected and evaluated information from various sources while developing the 2015 and 2020 rules, as described in Section 3 of the 2015 rule Technical Development Document (2015 TDD) and Section 2 of the 2020 rule Supplemental Technical Development Document (2020 Supplemental TDD), respectively. The EPA collected additional supplemental data for the 2024 final rule to update the industry profile; identify the steam electric power plants affected by the rule; reevaluate industry subcategorization; update plant-specific operations and wastewater characteristics; determine the technology options; and estimate the compliance costs, pollutant loadings and removals, and non-water quality environmental impacts of the technology options. This section briefly summarizes past data collection activities for the 2015 and 2020 rules (Section 2.1) and describes new data collection activities for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, legacy wastewater, and combustion residual leachate (CRL) for the 2024 final rule (Sections 2.2 through 2.4).

2.1 Summary of Data Collection for the 2015 and 2020 Rulemakings

For the 2015 and 2020 rules, the EPA collected and obtained information on the steam electric power generating industry from multiple sources including a detailed study of the industry, an information collection request (ICR), site visits, field sampling, Clean Water Act (CWA) section 308 industry requests, and voluntary requests as detailed below.

- *Detailed study.* The EPA studied the steam electric power generating industry between 2005 and 2009. Data collection included multiple site visits and six wastewater sampling episodes at steam electric power plants, a screener questionnaire sent to nine companies (operating 30 steam electric power plants), publicly available data sources, and outreach with EPA program offices, other governmental groups and industry stakeholders. The detailed study focused on wastewater from coal ash handling operations and from FGD air pollution control systems.
- *2009 Steam Electric Survey.* The EPA administered a survey to approximately 700 steam electric power plants to collect technical information related to wastewater generation and treatment, as well as economic information such as costs of wastewater treatment technologies and financial characteristics of potentially affected companies. The Agency used the responses to evaluate pollution control options for revising the effluent limitations guidelines and standards (ELGs) for the steam electric category, in addition to costs, loadings, and other rulemaking analyses.
- *Site visits.* The EPA conducted 73 site visits at steam electric power plants in 18 states between December 2006 and November 2014 to gather information about each plant's operation, pollution prevention and wastewater treatment options, and whether the plant was appropriate to include in the field sampling program. After promulgating the 2015 rule, between October and December 2017, the EPA conducted another seven site visits to steam electric power plants in five states to update information on methods for managing FGD wastewater and BA transport water. The EPA used data from site visits to update industry profile data; learn more about pollution control and wastewater treatment options evaluated as part of the rulemakings; and inform costs, loadings, and other rulemaking analyses.
- *Field sampling program.* For the 2015 rule, the EPA conducted 4-day sampling episodes at seven U.S. plants to obtain wastewater characterization data and wastewater treatment technology performance data. The EPA used these data in combination with other industry-supplied data to evaluate wastewater discharges from steam electric power plants and to evaluate technology options for managing these wastewaters. The sampling program primarily focused on wastewaters from wet FGD systems. The EPA also conducted a 3-day sampling episode at Enel's Federico II Power Plant (Brindisi), located in Brindisi, Italy, to characterize an FGD wastewater treatment system consisting of chemical precipitation followed by evaporation.

- *CWA 308 monitoring program.* For the 2015 rule, the EPA required four plants to collect four consecutive days of samples at two to four sampling locations chosen to characterize coal-gasification wastewaters, carbon capture wastewaters, and the treatment of FGD wastewater and coal-gasification wastewater by vapor-compression evaporation. These data were used to supplement the sampling data collected during the field sampling program.
- *Voluntary requests.* Following the 2015 rule, the EPA invited seven steam electric power plants to participate in a voluntary BA transport water sampling program. The EPA requested information from steam electric power plants operating surface impoundments that predominantly contain BA transport water. Plants were asked to provide sampling data for ash surface impoundment effluent and untreated BA transport water (*i.e.,* ash surface impoundment influent). Two plants chose to participate in the voluntary BA sampling program.
- *Other data sources.* The EPA used Electric Power Research Institute (EPRI) reports, data from the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA), information from literature and internet searches, and information from environmental groups to supplement the industry profile; learn more about pollution control and wastewater treatment options evaluated as part of the rulemakings; and inform costs, loadings, and other rulemaking analyses.

2.2 Site Visits and Industry-Submitted Data

In support of the 2024 final rule, the EPA participated in a virtual site visit with representatives from Duke Energy in 2021. The visit focused on Duke Energy's coal-fired generating units and the treatment and management of BA transport water, FGD wastewater, legacy wastewater, and CRL since the 2020 rule. The EPA also gathered information on steam electric power generating processes, wastewater treatment technologies, and wastewater characteristics directly from the industry through a CWA 308 request, two voluntary requests, and other industry data provided during the 2023 proposed rule. The EPA used this information to learn more about the performance of FGD, CRL, and legacy wastewater treatment systems and obtain information useful for estimating the cost of installing candidate treatment technologies. The EPA also used this information to learn more about BA system performance, characterization and quantification of the overflow and purge from remote mechanical drag system (MDS) installations, and treatment technologies and pilot testing associated with CRL and legacy wastewater. The EPA used this information to supplement the data collected in support of the 2015 and 2020 rules.

2.2.1 CWA 308 Request

In January 2022, the EPA requested the following information for coal-fired power plants from three steam electric power companies:

- FGD wastewater pilot testing and installation data, including configuration, pretreatment and post-treatment, byproduct handling, and sampling data for thermal technology, membrane filtration technology, paste, solidification, or encapsulation of FGD wastewater brine; electrodialysis, and electrocoagulation.
- Overflow from an MDS, compact submerged conveyor (CSC), or remote MDS installation including purge rate and management from remote MDS, as well as any pollutant concentration data to characterize the overflow or purge.
- CRL treatment from on-site or off-site testing (full-, pilot-, or laboratory-scale).
- On-site or off-site testing (full-, pilot-, or laboratory-scale) and/or implementation of treatment technologies associated with surface impoundment dewatering treatment.
- Costs associated with these technologies.

After meeting with these three companies, the EPA sent four other power companies a request inviting them to provide the same data described above.

In July 2023, the EPA requested full-, pilot-, or laboratory-scale data associated with on-site or off-site testing or implementation of a recently commissioned spray dryer evaporator for FGD wastewater and legacy wastewater at a coal-fired power plant from one steam electric power company. The EPA also requested information on pretreatment or disposal systems necessary for spray dryer evaporator operations and any corresponding documentation (*e.g.,* wastestreams, process flow diagram).

2.2.2 Voluntary Industry Sampling Requests

In December 2021, the EPA invited eight steam electric power companies to participate in a voluntary request program. The specific voluntary requests are outlined below.

- Existing CRL data consistent with the EPA's request.
- Untreated and treated samples of CRL on the sampling schedule laid out in the EPA's request.
- Grab samples of landfill solids and leachate samples analyzed using EPA Methods 1313 and 1316 (leaching evaluations).

2.3 Technology Vendor Data

The EPA gathered data from technology vendors through presentations, conferences, site visits, meetings, and email and phone contacts regarding the FGD wastewater, BA handling, CRL, and legacy wastewater technologies used in the industry. The EPA used the data to inform the development of the technology costs and pollutant removal estimates for FGD wastewater, BA transport water, CRL, and legacy wastewater. During the development of the 2015 and 2020 rules, the EPA participated in multiple technical conferences and reviewed the papers presented for information relevant to the steam electric rulemakings. The EPA referenced this information to inform the 2024 final rule.

2.3.1 FGD Wastewater, CRL, and Legacy Wastewater Treatment

The EPA contacted companies that manufacture, distribute, or install various components of biological wastewater treatment, membrane filtration, or thermal evaporation treatment systems for FGD wastewater, CRL, and legacy wastewater treatment. The EPA also contacted consulting firms that design and implement treatment technologies associated with these wastestreams. The vendors and consulting firms provided the following types of information for the 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 bid, procure, and install.
- Changes in the industry since 2020 including retirements or fuel conversions, new FGD installations, and planned future installations.

2.3.2 BA Handling

The EPA contacted vendors as well as consulting firms that design and implement BA handling systems. The vendors and consulting firms provided the following types of information for the 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 (HRR) systems.
- Equipment that can be reused as part of the conversion from wet to dry handling or in a HRR system.

- Outage time estimated for installing the different types of ash handling systems.
- Maintenance estimated for each type of system.
- Estimated capital and O&M costs.
- Changes in the industry since 2020 including retirements or fuel conversions, new BA installations, and planned future installations.
- Purge from complete recycle systems, purge from under-boiler mechanical drag systems, and purge wastewater characteristics.

2.4 Public Comments and Public Hearing

During the 60-day public comment period for the 2023 proposed rule (March 29 to May 30, 2023), the EPA received more than 22,000 public comment submissions from private citizens, industry members, technology vendors, environmental groups, and trade associations. The EPA also hosted two online public hearings on April 20 and 25, 2023, where the public could voice comments on the proposed rule. The online hearings had 196 registered attendees, and 46 elected to provide comment. Available documents from the public hearing include the presentation given by the EPA and a transcript of the webinar (U.S. EPA, 2023 and 2023a).

2.5 Other Data Sources

The EPA gathered information on steam electric power generating processes, wastewater treatment, wastewater characteristics, and regulations from sources including EPRI, DOE, literature and internet searches, notices of planned participation (NOPPs), environmental groups, residents of affected communities, state and local governments, Tribes, and reporting by utilities via the "CCR Compliance Data and Information" websites required by the Coal Combustion Residuals (CCR) rule. Sections 2.5.1 through 2.5.6 summarize the data collected from these additional sources.

2.5.1 EPRI

EPRI conducts studies funded by the steam electric power generating industry to evaluate and demonstrate technologies that can potentially remove pollutants of concern from wastestreams or eliminate wastestreams using zero-discharge technologies. The EPA reviewed reports—listed in Table 1—that EPRI voluntarily provided, or that were provided in CWA 308 responses. These reports contained information relevant to characteristics of FGD wastewater, CRL and legacy treatment pilot studies, BA transport water characterization and BA handling practices.

Table 1. EPRI Reports and Studies Reviewed by the EPA for the 2024 Rule

Title of Report/Study	Date Published	Document Control Number
Effects of Alkaline Sorbents and Mercury Controls on Fly Ash and FGD Gypsum Characteristics and Implications for Disposal and Use	2014	SE10395
Review of Solidification/Stabilization Additives for Coal Combustion Fly Ash	2014	SE11719
Coal Combustion Residuals Leachate Management: Characterization of Leachate Quantity and Evolution of Leachate Minimization and Management Methods	2015	SE10386
Coal Combustion Residuals Leachate Management: Characterization of Leachate Quality	2016	SE10387
Evaporation Treatment of Flue Gas Desulfurization Wastewater	2017	SE06970
Landfill Leachate Characterization, Management and Treatment Options	2017	SE06959
Brine Encapsulation Laboratory Study	2018	SE10296

Table 1. EPRI Reports and Studies Reviewed by the EPA for the 2024 Rule

Title of Report/Study	Date Published	Document Control Number
Wastewater Encapsulation Testing References: Encapsulating Co-Management of Liquid Waste with Combustion Byproducts at Bench and Field Scale	2018	SE10295
Mercury, Methylmercury, and Selenium Interactions in Freshwater Fish	2018	SE10388
Performance Evaluation of the Vacom Thermal Vapor Recompression Technology for FGD Wastewater Treatment	2019	SE10389
Membrane Treatment Guidelines	2019	SE10297
Considerations for Treating Flue Gas Desulfurization Wastewater Using Membrane and Paste Encapsulation Technologies	2019	SE10396
Studies on the Encapsulation of Brine Generated from a Process Using Selective Electrodialysis Reversal	2020	SE10397
Landfill Leachate Treatment Study: Evaluations of Membrane, Evaporation, and Encapsulation Technologies	2020	SE10385
The Impacts of High Salinity Wastewater Chemistry and Fly Ash Reactivity on Encapsulation	2020	SE10298
Thermal Water/Wastewater Treatment System Chemistry Guidelines	2020	SE10390
Real-Time Online Membrane Monitor Demonstration	2020	SE10300
Understanding Chemical Reactions and Mineral Additives for Wastewater Encapsulation	2020	SE10299
Conference Proceedings of the 2020 Virtual Selenium Summit	2020	SE10391
FGD Wastewater Treatment Testing Using a Saltworks Flex EDR Selective Electrodialysis Reversal System Technology	2020	SE10398
Quantifying Leachate Volumes at Four Coal Combustion Product Landfills in the Southeastern United States	2021	SE10392
Review of Coal Combustion Product Leaching	2021	SE10393
Review of Established and Emerging Boron Treatment Technologies for Water at Coal Combustion Product Sites	2021	SE10399
Water Flow in Coal Combustion Products and Drainage of Free Water	2021	SE10394
Coal Combustion Product Landfill Terminology and Water Management Fundamentals	2021	SE10400
Leaching, Geotechnical, and Hydrologic Characterization of Coal Combustion Products from an Active Coal Ash Management Unit	2021	SE11718

2.5.2 Department of Energy

The EPA compiled information on steam electric power plants from EIA's Form EIA-860, *Annual Electric Generator Report,* and Form EIA-923, *Power Plant Operations Report.* The data collected in Form EIA-860 concern the design and operation of generators at plants, while data collected in Form EIA-923 concern the design and operation of the entire plant. The EPA used relevant data from EIA-923 and EIA-860 from 2009 to 2022 (U.S. DOE, 2021, 2021a). The EPA used these data to update the industry profile from the 2020 rule, including commissioning dates, energy sources, capacity, net generation, operating statuses, planned retirement dates, ownership, and pollution controls of the generating units. Consistent with the 2020 rule analyses, the 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 Office of Land and Emergency Management

The 2015 CCR rule established requirements for the safe disposal of CCRs from coal-fired steam electric power plants. The CCR regulations require 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.

The EPA used plant-specific information on CCR landfills and surface impoundments from the EPA's Office of Land and Emergency Management (OLEM) as part of its CRL and legacy analyses. In September 2023, the EPA's OLEM provided the Office of Water with publicly available CCR compliance information for 779 CCR waste management units, corresponding to 302 facilities, subject to the CCR Part A rule requirements (U.S. EPA, 2023b).

2.5.4 Power Company CCR Websites

As described in Section 2.5.3, the 2015 CCR rule established requirements for the safe disposal of CCRs from coal-fired steam electric power plants and 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. The EPA searched these websites for CCR unit-specific documents including:

- Closure plans/reports
- Liner certifications
- Run-on/run-off control plans
- Annual inspection reports
- Annual groundwater monitoring plans and corrective action reports
- Groundwater monitoring system design reports

See the EPA's memoranda *Evaluation of Unmanaged CRL* and *Legacy Wastewater at CCR Surface Impoundments* for more details on how this information was used as part of the EPA's unmanaged CRL and legacy analyses (U.S. EPA, 2024, 2024a).

2.5.5 Literature and Internet Searches

The EPA conducted literature and internet searches to gather information on FGD wastewater, CRL, and legacy wastewater treatment technologies, including information on pilot studies, applications in the steam electric power generating industry, and implementation costs and timeline. The EPA also used Internet searches to identify or confirm reports of planned plant/unit retirements or reports of planned unit conversions to dry or HRR ash handling systems. The EPA used industry journals and company press releases obtained from Internet searches to inform the industry profile and process modifications occurring in the industry.

2.5.6 Intergovernmental and Tribal Listening Sessions

As part of the 2024 supplemental rulemaking process, the EPA held consultation and coordination proceedings with intergovernmental agencies and Tribal governments, refer to *Summary of Input from State, Local Government, and Tribal Consultations* memorandum for additional information (U.S. EPA, 2023c). Consultations pursuant to Executive Order 13132, entitled "Federalism," and the Unfunded Mandates Reform Act (UMRA) were held January 27, 2022. The EPA received five sets of unique written comments after the meeting, including two comments from trade associations representing public water systems. These comments generally recommended more advanced treatment to reduce the pollutants making their way downstream to intakes for government-owned public water systems or, alternatively, to empower states to more effectively address these discharges. The remaining three comments came from the American Public Power Association and two of its member utilities. These comments recommended the retention of existing limitations and subcategories, a careful consideration of the CRL definition and BAT, and a compliance pathway for utilities that installed or are in the process of installing technologies to comply with the 2015 and 2020 rules compliant technologies. The EPA also held listening sessions via webinars with Tribal representatives on February 1 and 9, 2022. Following these consultations, the EPA received written comments from three Tribes: the Sault Ste. Marie Tribe of Chippewa Indians, the Mille Lacs Band of Ojibwe, and the Little Traverse Bay Bands of Odawa Indians. These comments conveyed the importance of historical Tribal waters and rights (*e.g.,* fishing, trapping) and recommended more stringent technological controls or encouraged retirement or fuel conversion of old coal-fired units to protect those rights.

2.5.7 Communities

In support of its environmental justice analysis, the EPA conducted a screening-level analysis of pollution exposures to potentially affected communities and identified nine communities with EJ concerns. The EPA planned outreach to community members to discuss ideas and strategies for limiting pollution from steam electric power plants, concerns related to these plants or other sources of pollution including impacts to nearby rivers, lakes, and streams or drinking water; and community health, social, and economic concerns. The EPA conducted initial outreach to local environmental and community development organizations, local government agencies, and individual community members. Between May and September 2022, the EPA held listening sessions with community members in five of the identified communities. Each meeting began with a presentation providing background information about the 2023 proposed supplemental rulemaking before opening the meeting for questions and comments from community members.

- The EPA received a broad range of input from individuals in these communities on regulatory preferences, environmental concerns, human health and safety concerns, economic impacts, cultural/spiritual impacts, ongoing communication/public outreach, and interest in other EPA actions. Three broad themes conveyed consistently across communities included:
- Community members perceive harmful impacts from steam electric power plants and desire more stringent regulations to reduce these harmful impacts.
- Community members desire more transparency to overcome their decreasing trust in the regulated plants and state regulatory agencies.
- Community members would prefer increased communication to understand the compliance of steam electric power plants.

Commenters also raised concerns unique to each community. For example, members of the Navajo Nation discussed with the EPA the spiritual and cultural impacts to the community from pollution related to steam electric power plants. In Jacksonville, Florida, community members raised concerns regarding tidal flows of pollution upstream and storm surges during extreme weather events that cause additional challenges in their community. See the *Environmental Justice Analysis for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on these meetings (U.S. EPA, 2024b).

2.5.8 Notices of Planned Participation (NOPPs)

The 2020 rule required facilities to file a NOPP with their permitting authority no later than October 13, 2021, where the facility wished to participate in the low utilization electric generating unit (LUEGU) subcategory, the permanent cessation of coal combustion subcategory, or in the VIP. The direct final rule promulgated in March 2023 extended this NOPP date to June 27, 2023. While the EPA did not require that NOPPs be submitted to the Agency, the EPA obtained a number of these filings through various means including its standard permit review process, a plant providing the EPA a courtesy copy, the EPA states for their NOPPs, and environmental groups tracking NOPPs and sharing the information they had collected with the EPA. The EPA is currently aware of NOPPs covering 90 EGUs at 38 plants. At the time of the 2023 proposed rule, four EGUs (at two plants) requested participation in the LUEGU subcategory, an additional 12 EGUs (at four plants) requested participation in the 2020 rule VIP, and the remaining 74 EGUs (at 33 plants) requested participation in the permanent cessation of coal combustion subcategory (U.S. EPA, 2024c). Note that at least one plant (Plant Scherer) filed a permanent cessation of coal combustion NOPP for two EGUs and a 2020 rule VIP NOPP for the remaining two EGUs; thus, these groups are not additive. Following the 2023 direct final rule, the EPA obtained one additional NOPP stating that two EGUs (at one plant) requested participation in the permanent cessation of coal combustion subcategory instead of the 2020 rule VIP. The EPA notes that these counts are not a comprehensive picture of plants' plans for two reasons. First, the EPA was unable to obtain information for all plants and states; second, plants retain flexibility to transfer between subcategories through 40 CFR 423.13(o)(1)(ii). See Preamble Section VI.B for more information about NOPPs.

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, the EPA took precautions to prevent the inadvertent disclosure of this CBI. The Agency withheld CBI from the public docket in the Federal Docket Management System. In addition, the EPA found it necessary to withhold from disclosure some data not directly claimed as CBI because the release of these data could indirectly reveal CBI. Where necessary, the EPA 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.

3. Current State of the Steam Electric Power Generating Industry

For the 2015 rule, the U.S. Environmental Protection Agency (EPA) generated a comprehensive industry profile using 2009 Department of Energy (DOE) Energy Information Administration (EIA) data, data from the EPA's 2009 *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey), and U.S. Census Bureau data from 2007. See Section 4 of the 2015 rule's Technical Development Document (TDD). For the 2020 rule, the EPA updated the industry profile to account for current plant operations and plans for future modifications. See Section 3 of the 2020 Supplemental TDD.

For the 2024 final rule, the EPA updated the industry profile, evaluated changes in wastewater management practices, and assessed how other regulations have affected steam electric power plants since the 2020 rule analyses. This section describes the current state of the steam electric power generating industry as it relates to the technical aspects of the 2024 final rule, including the following:

- Changes in the steam electric power plant population (Section 3.1).
- Current information on evaluated wastestreams (Section 0).
- Other regulations affecting the steam electric power generating industry (Section 3.3).

3.1 Changes in the Steam Electric Power Generating Industry Since the 2020 Rule

The steam electric power generating industry is dynamic; the Agency recognizes that industry demographics and plant operations have changed since the 2020 rule analyses were completed.[9] Therefore, the EPA collected information on current plant operations and plans for future modifications to augment industry profile data collected for the 2015 and 2020 rules. This section discusses changes in the number and operating status of coal-fired electric generating units (EGUs) and updates to wet flue gas desulfurization (FGD) systems, FGD wastewater treatment, bottom ash (BA) handling systems, coal combustion residual (CCR) landfills and surface impoundments, and legacy wastewater.

The EPA gathered information from public sources, including company announcements and EIA data, to account for the following types of operation changes that have occurred or been announced since the 2020 rule analyses:

- Commissioning of new coal-fired EGUs.
- Retirement of coal-fired EGUs.[10]
- Fuel conversions of coal-fired EGUs from coal to another fuel source, such as natural gas or hydrogen fuel cells.
- Installation of wet FGD systems.
- Installation of, or conversion to, zero-discharge FGD wastewater treatment systems.

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[9] The EPA's 2020 rule analyses accounted for all industry profile changes announced and verified as of February 2020 that are in effect until 2028.

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

- Installation of, or conversion to, zero-discharge BA handling systems, such as dry BA handling and closed-loop recycle wet BA systems.[11]
- Addition of CCR landfills.
- Addition of CCR surface impoundments.

The EPA identified 235 coal-fired EGUs at 125 plants from the 2020 rule profile with at least one significant change in operation taking place by December 31, 2028 (the date on which the 2020 rule's subcategory for EGUs permanently ceasing coal combustion by December 31, 2028 is based). Table 2 presents the count of steam EGUs and plants, broken out by type of operation change for the 2024 rule.

Table 2. Industry Profile Updates Incorporated Since the 2020 Rule by Type of Change in Operation

Change in Operation	Count	
	EGUs	Plants
Commissioning of a new coal-fired EGU	0	0
Retirement of coal-fired EGU [a]	187	104
Fuel conversion to non-coal fuel type [b]	43	24
Installation of wet FGD system	1	1
Installation of zero-discharge FGD wastewater treatment system	5	2
Addition of CCR landfill	NA	39
Addition of CCR surface impoundment	NA	6

a—The EPA estimates an additional 52 coal-fired EGUs at 25 plants will retire between January 1, 2029, and December 31, 2034, and an additional 20 coal-fired EGUs at 13 plants will retire after January 1, 2035.

b—The EPA estimates an additional six coal-fired EGUs at four plants will convert to a non-coal fuel type between January 1, 2029 and December 31, 2034, and an additional 41 coal-fired EGUs at 18 plants will convert to a non-coal fuel type after January 1, 2035.

Figure 1 illustrates the change in the number of operating coal-fired EGUs and plants for the Steam Electric Survey, 2015 rule, 2020 rule, and 2024 rule. The population of coal-fired EGUs and plants decreased to 277 EGUs at 148 plants for the 2024 final rule, 35 percent fewer EGUs than the 2020 rule population.

Section 5 and Section 6 describe how the EPA accounted for the changes in operation identified in Table 2 in estimating compliance costs, pollutant loadings, and pollutant removals for the 2024 rule. More information on the specific coal-fired EGUs and plants identified as implementing each type of operation change is discussed in the memorandum titled *Changes to the Industry Profile for Coal-Fired Electric Generating Units for the 2024 Final Steam Electric ELGs* (U.S. EPA, 2024c).

[11] For this discussion, dry BA handling systems include all systems that do not generate BA transport water.

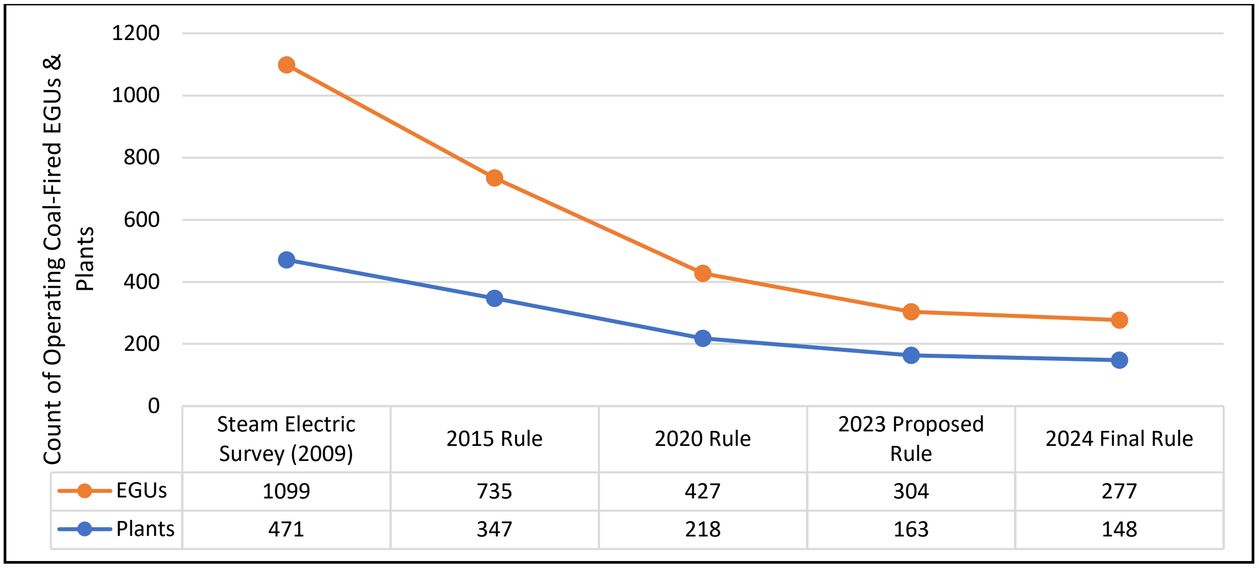

Figure 1. Change in Population of Coal-Fired EGUs and Plants[12]

3.2 Current Information on Evaluated Wastestreams

This section summarizes current information on the generation and discharge of FGD wastewater, BA transport water, CRL, and legacy wastewater that the EPA collected for the 2024 final rule.

3.2.1 FGD Wastewater

As discussed in Section 3, the EPA updated the industry profile to reflect coal-fired EGUs that will retire, convert fuels, or upgrade FGD wastewater treatment prior to December 31, 2028. Of the 277 coal-fired EGUs at 148 steam electric power plants in the updated profile, 127 EGUs at 57 plants are serviced by a wet FGD system. The EPA estimates EGUs with wet FGD systems have a total generating capacity of 77,854 megawatts (MW), representing approximately 63 percent of the industry's total coal-fired capacity.

Figure 2 shows the locations of plants operating wet FGD systems servicing at least one coal-fired EGU. In addition to wet FGD scrubbers, the EPA estimates that there are 38 plants operating dry FGD scrubbers servicing at least one coal-fired EGU in the industry. Although dry FGD scrubbers use water in their operation, the water in most systems evaporates, and they generally do not discharge wastewater. The EPA did not evaluate the wastewater generated from these dry FGD systems as part of the 2024 rule, and they are not subject to the FGD wastewater requirements in the ELGs.

[12] The 2015 rule analyses accounted for profile changes expected to occur before December 31, 2023 (the latest date that power plants were expected to comply with the established BAT effluent limitations), whereas the 2020 rule and the 2024 rule account for changes expected to occur before December 31, 2028.

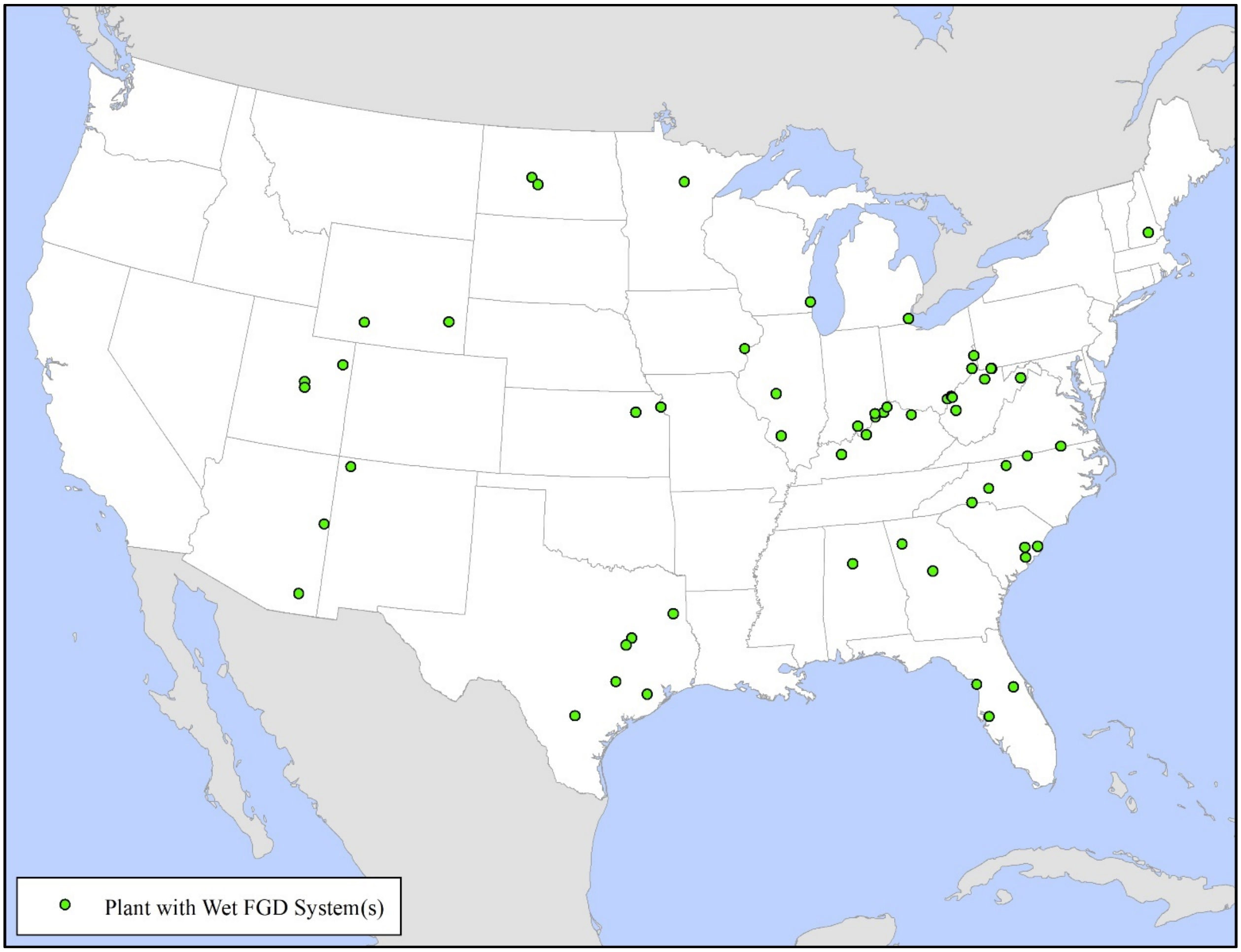

Figure 2. Wet FGD Systems at Steam Electric Power Plants

Although the number of wet FGD systems operated at steam electric power plants has decreased since promulgation of the 2020 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 to remove sulfur dioxide (SO_2) from flue gas from EGUs burning bituminous coal. Often, plants also operate selective catalytic reduction systems on these EGUs to reduce NO_X emissions.

Following promulgation of the 2015 rule, the EPA collected new information on air pollution control practices at steam electric power plants that may affect the characteristics of FGD wastewater. Specifically, the EPA found that steam electric power plants may add halogens (*e.g.,* bromine, chlorine, iodine) to reduce mercury air emissions. While all coal contains 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, 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.

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, low residence time reduction (LRTR) biological treatment, high residence time reduction (HRTR) biological treatment, advanced membrane filtration, spray dryer evaporators, and thermal evaporation treatment systems. The EPA identified that approximately 54 percent of steam electric power plants with wet FGD scrubbers have technologies in place or plan to install technologies that will meet the best available technology economically achievable (BAT) effluent limitations for FGD wastewater, including membrane filtration systems or other FGD wastewater management approaches that eliminate the discharge of FGD wastewater altogether. The EPA identified three domestic installations of spray evaporation technologies treating FGD wastewater and six installations of spray evaporation systems treating FGD wastewater in Asia. See Section 4 for more details on the treatment technologies some steam electric power plants employ to treat or reduce FGD wastewater discharges. Table 3 summarizes the FGD wastewater discharges from the steam electric power plants included in the EPA's costs and loadings analyses.

Table 3. FGD Wastewater Discharges from Steam Electric Power Plants

		FGD Wastewater Discharge Flow Rate			
Number of Plants	Number of EGUs	Total Daily Discharge Purge Flow Rate (MGD)	EGU Average Daily Discharge Purge Flow Rate (MGD per EGU)	Total Annual Discharge Purge Flow Rate (MGY)	EGU Annual Discharge Purge Flow Rate (MGY per EGU)
28	69	16.2	0.234	5,910	85.6

Abbreviations: MGD (million gallons per day), MGY (million gallons per year).

Note: Counts and flow rates do not include EGUs that will retire or convert fuels by December 31, 2028. In addition, this table does not include wet FGD systems at plants that are already achieving zero discharge.

3.2.2 BA Transport Water

Based on the Steam Electric Survey, approximately two-thirds of coal-fired power plants operated wet BA handling systems in 2009. Some plants operating wet BA handling systems recycled BA transport water from surface 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 zero-discharge BA handling systems—dry, closed-loop recycle, or high recycle rate (HRR) systems. Because of changes in the industry in the years following the Steam Electric Survey, by 2015 more than half of EGUs operated or planned to convert to zero-discharge BA handling systems.

As discussed in Section 3, the EPA updated the industry profile and corresponding analyses to account for coal-fired EGUs that will retire, convert fuels, or install zero-discharge BA handling systems before December 31, 2028. Since the 2015 and 2020 rules, more plants have converted or are converting to dry BA handling systems or closed-loop BA handling systems, thereby eliminating discharge of BA transport water. In addition, based on data from the Steam Electric Survey, EGUs commissioned after 2009 likely operate dry or closed-loop recycle BA handling systems.[13] Further, the number of coal-fired EGUs operating wet-sluicing systems has decreased due to plant retirements and fuel conversions. Table 4 presents the count and total generating capacity of the EGUs operating wet-sluicing, closed-loop recycle and/or HRR, or dry BA handling systems. For the 2020 rule, the EPA estimated that more than 75 percent of EGUs operate either dry, closed-loop recycle, or HRR BA handling systems.[14] Based on conversations

[13] Data from the Steam Electric Survey show that more than 80 percent of EGUs built in the 20 years preceding the survey (1989–2009) installed dry BA handling systems at the time of construction. Because dry BA technologies are less expensive to operate than wet-sluicing systems and facilitate beneficial use of the BA, it is unlikely that power companies would find it advantageous to install wet-sluicing BA handling systems.

[14] Counts presented in this paragraph and Table 4 do not reflect BA handling conversions expected as a result of the CCR Part A rule.

with people in the steam electric industry, the EPA is aware that plants are still working to comply with the 2020 rule. Figure 3 illustrates the geographic distribution of plants operating the systems noted in Table 4. Plants that operate more than one type of system are shown as wet sluicing (with limited/no recycle or closed-loop/HRR, whichever is applicable).

Table 4. BA Handling Systems for Coal-Fired EGUs

Type of System	Number of Plants	Number of EGUs	Nameplate Capacity (MW)
Wet-sluicing system with limited or no recycle	24	58	27,700
Wet-sluicing closed-loop/HRR system	22	57	29,100
Dry BA handling system[a]	87	136	55,800
Total	**145**	**271**	**120,600**

Note: Counts and flow rates do not include EGUs that will retire or convert fuels by December 31, 2028.

a—The dry BA handling system counts presented in this table reflect conversions the EPA identified in the Steam Electric Survey and publicly available information from 2009 or later. Where data were available, the EPA tracked the specific types of BA handling conversions, such as mechanical drag systems (MDS) and remote MDS. However, the EPA identified 20 EGUs (corresponding to 8,000 MW at 12 plants) for which the data confirmed that the plant was not discharging BA transport water but did not confirm the specific type of non-discharging system.

b—Plant counts are not additive because plants may operate multiple types of BA handling systems.

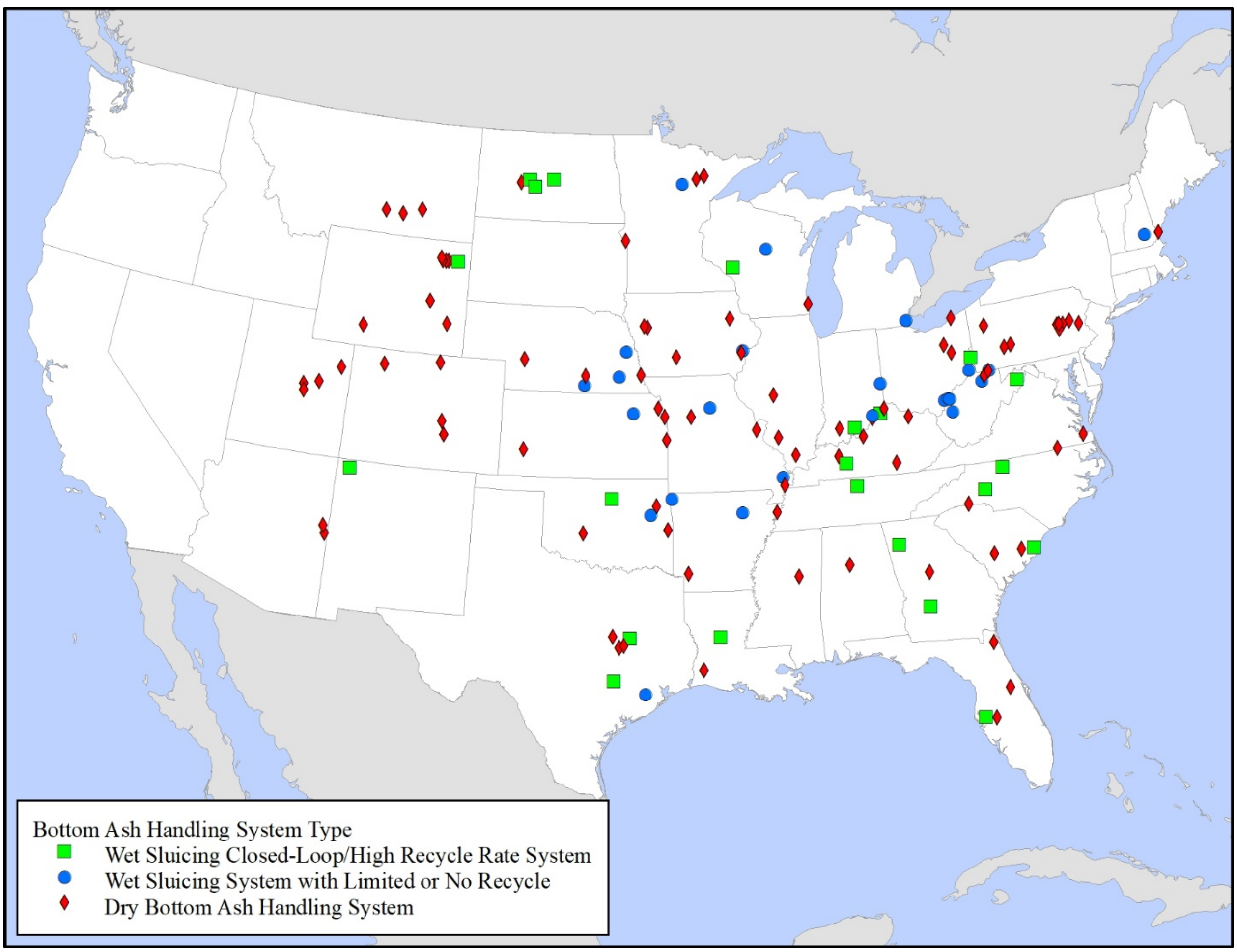

Figure 3. Plant-Level BA Handling Systems in the Steam Electric Power Generating Industry

Table 5 summarizes BA transport water discharges by the steam electric power plants included in the EPA's costs and loadings analyses. The estimated flow rates are based on compliance with the 2020 rule, which may represent full sluicing operations or a 10 percent allowable purge.

Table 5. BA Transport Water Discharges for the Steam Electric Power Plants

BA Wastewater Discharge Flow Rate					
Number of Plants	Number of EGUs	Total Daily Discharge Flow Rate (MGD)	EGU Average Daily Discharge Flow Rate (MGD per EGU)	Total Annual Discharge Flow Rate (MGY)	EGU Annual Discharge Flow Rate (MGY per EGU)
34	90	6.53	0.073	2,380	26.5

3.2.3 CRL

The EPA used data from the 2009 Steam Electric Survey (U.S. EPA, 2015) and the Office of Resource Conservation and Recovery's (ORCR's) Comprehensive Compliance Report (U.S. EPA, 2023b) to identify the population of landfills and surface impoundments containing combustion residuals that collect and discharge CRL to surface waters or publicly owned treatment works (POTWs). For the 2024 final rule, the EPA updated this data set to remove plants that intend to retire all coal-fired EGUs as of December 31, 2023, and add plants that either have constructed new landfills or surface impoundments since 2015 or have landfills or surface impoundments that were identified as having a composite liner as described in *Identification of Combustion Residual Leachate (CRL) Discharges from Leachate Collection Systems and Overview of Compliance Costs and Pollutant Loadings Analyses* (U.S. EPA, 2024d).[15] Table 6 summarizes CRL discharges by the steam electric power plants included in the EPA's costs and loadings analyses.

Table 6. CRL Wastewater Discharges for the Steam Electric Power Plants

CRL Wastewater Discharge Flow Rate					
Number of Plants	Number of EGUs	Total Daily Discharge Flow Rate (MGD)	EGU Average Daily Discharge Flow Rate (MGD per EGU)	Total Annual Discharge Flow Rate (MGY)	EGU Annual Discharge Flow Rate (MGY per EGU)
90	211	7.52	0.036	2,740	13.0

The EPA also notes that unlined landfills and surface impoundments potentially discharge unmanaged CRL that consists of: (1) discharges of CRL that the permitting authority determines are the functional equivalent of a direct discharge to Waters of the United States (WOTUS) through groundwater or (2) discharges of CRL that has leached from a waste management unit into the subsurface and mixed with groundwater prior to being captured and pumped to the surface for discharge directly to a WOTUS. As stated in the preamble, the EPA is not determining that all discharges through groundwater from landfills and surface impoundments are the functional equivalent of a direct discharges from a point source to a WOTUS. Rather, the EPA is establishing limitations that apply to any discharge of this kind that a permitting authority or facility owner or operator determines to be the functional equivalent of a direct discharge from a point source to a WOTUS, and thus requires an NPDES permit. The threshold standard for the "functional equivalence" determination is outside the scope of the final rule. The EPA analyzed the

15 If a plant in the CRL population converted to a different fossil fuel source (*e.g.,* gas-fired source), the 2024 final rule still applies, and the plant remains in the CRL population.

potential costs and loadings associated with these discharges in both upper and lower bound scenarios documented in its memorandum *Evaluation of Unmanaged CRL* (U.S. EPA, 2024).

3.2.4 Legacy Wastewater

Legacy wastewater can be comprised of FGD wastewater, BA transport water, FA transport water, CRL, gasification wastewater, and/or flue gas mercury control (FGMC) wastewater generated before the "as soon as possible" date that more stringent effluent limitations from the 2015 or 2020 rules would apply. Discharges of legacy wastewater may occur through an intermediary source (*e.g.,* a tank or surface impoundment) or directly into a surface waterbody, with the vast majority of legacy wastewater currently contained in surface impoundments treating the wastestreams listed above. The EPA identified CCR units from the 2009 Steam Electric Survey (U.S. EPA, 2015) and ORCR's Comprehensive Compliance Report (U.S. EPA, 2023b). The EPA then used this list to identify the population of steam electric power plants that are expected to discharge legacy wastewater either directly into a surface waterbody or through an intermediate structure after the 2024 final rule takes effect. This population includes steam electric power plants with impoundments that are not required to have initiated closure under the CCR regulations prior to the effective date of the 2024 final rule (classified as "remaining open") and steam electric power plants with CCR surface impoundments that are expected to have initiated, but not yet completed closure prior to the effective date of the 2024 final rule (classified as "in closure process"). Plants that have completed the closure process for all impoundments are not expected to have legacy flows that would be subject to 2024 final rule. Table 7 summarizes discharges of these types of legacy wastewater. See Section 5.4.1 and the *Legacy Wastewater at CCR Surface Impoundments* memorandum (U.S. EPA, 2023b, 2024a) for details on the estimated volume and cost calculations.

Table 7. Estimate of Total Volume of Wastewater in CCR Surface Impoundments

Category	Total Number of Surface Impoundments	Total Estimated Volume of Wastewater (million gallons)
CCR surface impoundments that are remaining open	24	2,150
CCR surface impoundments in closure process	109	60,000

Source: U.S. EPA, 2024a.

Note: The EPA identified 398 additional surface impoundments that are expected to complete closure prior to the effective date of the 2024 final rule and therefore were not considered in 2024 final rule analyses.

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 to control pollution emissions, discharges, and other releases from steam electric power plants. For the 2020 rule, the EPA assessed and incorporated impacts from the CCR regulations into the supporting analyses.

The EPA continues to account for industry profile changes associated with the CCR regulations. The EPA coordinated the requirements of the CCR regulations and the 2015 rule to mitigate potential impacts from the overlapping regulatory requirements and facilitate the implementation of engineering, financial, and permitting activities. Based on the CCR regulation requirements established in 2015, the EPA expected plants might alter how they operate their CCR surface impoundments in some of the following ways:

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

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

As discussed in Section 1.3, the EPA finalized the CCR Part A rule on July 29, 2020, setting a deadline of April 11, 2021, for all unlined surface impoundments and surface impoundments that failed the location restriction for placement above the uppermost aquifer to stop receiving waste and begin closure. For the 2020 rule, the EPA developed a methodology for using CCR surface impoundment liner data to estimate operational changes at each coal-fired power plant under the CCR Part A rule. As described in Section 3.3 of the 2020 Supplemental TDD, plants with unlined or clay-lined CCR surface impoundments are required to change operation (*e.g.,* convert to dry handling) or install a new CCR-compliant surface impoundment. The EPA incorporated the CCR outputs into the 2020 rule (*i.e.,* baseline) engineering costs and loadings analyses in the following ways:

- Where all active CCR surface impoundments are unlined or clay-lined, the EPA predicted that a plant would install tank-based FGD wastewater treatment or tank-based BA handling under the CCR Part A rule.[16]
- For plants with at least one CCR surface impoundment not affected by the CCR Part A rule (*i.e.,* not identified as unlined or clay-lined,[17] or where no data were available in the ORCR data set), the EPA conservatively assumed the CCR Part A rule would have little to no impact on a plant's existing FGD wastewater treatment or BA handling systems. Thus, for these plants, the estimated compliance cost and pollutant loadings remain unchanged for the 2024 final rule.

For the 2024 final rule, the EPA determined that 50 plants within the BA engineering costs and loadings baseline analyses likely made changes to BA handling operations under the CCR Part A rule.[18] These changes were captured as part of the EPA's 2020 final rule (and reflected in the 2024 final rule baseline). Sections 5 and 6 of the 2020 Supplemental TDD describe how the EPA accounted for CCR Part A rule impacts in estimating BA compliance costs, pollutant loadings, and pollutant removals.

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

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

[18] Any plant that installs a remote MDS to comply with the CCR Part A rule may incur costs to install a reverse osmosis system that will treat a slipstream of the recirculating BA transport water to remove dissolved solids and facilitate long-term operation of the system as a closed loop to comply with the BA zero-discharge requirements of the 2015 rule. There are approaches other than reverse osmosis to remove dissolved solids from the BA system, 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 dredged BA.

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; bottom ash (BA) transport water; combustion residual leachate (CRL) collected from landfills and surface impoundments containing combustion residuals; and legacy wastewater. This section focuses on only those technologies and practices considered as potential technology options for this 2024 rule: it is not a comprehensive listing of all technologies available for treatment and management of FGD wastewater, BA transport water, CRL, or legacy wastewater. For the U.S. Environmental Protection Agency's (EPA's) comprehensive evaluation of available technologies and practices for the 2015 rule and 2020 reconsideration, see the 2015 Technical Development Documents (TDD) and the 2020 Supplemental TDD. Also see the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering—2024 Final Rule* memorandum (U.S. EPA, 2024e) for details on other types of treatment technologies available.

This section discusses the following:

- FGD wastewater treatment technologies (Section 4.1).
- BA handling systems and transport water management and treatment technologies (Section 4.2).
- CRL treatment technologies and management practices (Section 4.3).
- Legacy wastewater treatment technologies (Section 4.4).

4.1 FGD Wastewater Treatment Technologies

For the 2024 rule, the EPA considered treatment technologies identified as part of the 2015 and 2020 rules for those plants that are still operating and discharging FGD wastewater. These technologies include low residence time reduction (LRTR) biological treatment and membrane filtration. The EPA also evaluated other treatment technologies capable of achieving zero discharge of FGD wastewater including spray evaporation, other types of thermal treatment, and encapsulation.

4.1.1 LRTR Biological Treatment

Several types of biological treatment systems are used to treat FGD wastewater, including:

- Anoxic/anaerobic biological treatment systems, designed to remove selenium and other pollutants.
- Sequencing batch reactors, designed to remove nitrates and ammonia.
- Aerobic bioreactors for reducing biochemical 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. The microorganisms reduce the selenate and selenite to elemental selenium, which forms nanospheres that adhere to the cell walls of the microorganisms. The technology can also remove other metals, including arsenic, cadmium, nickel, and mercury, by forming metal sulfides (Pickett, 2006).

As defined in the 2020 reconsideration, an LRTR biological treatment system consists of chemical precipitation[19] followed by an anoxic/anaerobic fixed-film bioreactor. In the years since it first identified anoxic/anaerobic biological technology in the 2015 rule, the EPA identified different systems with varying hydraulic residence times (HRT) in the bioreactor. During the development of the 2020 reconsideration, the EPA differentiated between high residence time reduction (HRTR) systems (which typically operate with HRT in the bioreactor between 10 and 16 hours) and LRTR systems (with HRT between one and four hours). Power companies and technology vendors have worked to develop processes that target removals of the same pollutants in a smaller system with a lower HRT in the bioreactor. These LRTR technologies use similar treatment mechanisms as HRTR to remove selenium, nitrate, nitrite, and other pollutants in less time.

One LRTR technology includes a chemical precipitation system followed by an anoxic, upflow bioreactor followed by a second stage downflow biofilter. The shorter HRT 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 LRTR's performance is comparable to HRTR's. Much of the LRTR bioreactor and related equipment is fabricated off site as modular components. Modular, prefabricated, skid-mounted components, coupled with smaller physical size, result in lower installation costs and shorter installation times than for HRTR systems, which are usually constructed on site. At least three plants have installed full-scale LRTR systems and are using them 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 been used to treat selenium in mining wastewaters; 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 microbes grow on a granular activated carbon medium that is fluidized by the upflow of FGD wastewater through the suspended carbon medium. The EPA identified 12 pilot studies of the FBR technology for selenium removal in mining, refining/petrochemical, and steam electric power generating industries. For the steam electric power generating industry, the EPA identified three pilots involving FGD wastewater.

4.1.2 Membrane Filtration

Membrane filtration systems are specifically designed to treat wastestreams high in total dissolved solids (TDS) and total suspended solids (TSS) using thin semi-permeable filters or film membranes. Membrane filtration is used for the removal of dissolved materials from industrial wastewater and consists of one or more of the following: microfiltration, ultrafiltration, nanofiltration, reverse osmosis (RO), forward osmosis (FO), and electrodialysis reversal (EDR) membrane systems. As part of the 2020 reconsideration, the EPA identified several membrane filtration technologies being studied for use with FGD wastewater, including nanofiltration membranes, RO, and FO. The membrane pore size determines the particle size that can pass through the membrane, with RO membranes being the most restrictive and microfiltration being the least restrictive. Most membrane filtration systems use pumps to apply pressure to the solution from one side of the semi-permeable membrane to force wastewater through the membrane, leaving behind dissolved solids retained ("rejected") by the membrane and a portion of the water. The rate at which water passes through the membrane depends on a number of variables including the operating pressure, concentration of dissolved materials, and temperature, as well as the permeability of the membrane.

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,

[19] Consistent with both the 2015 and 2020 reconsideration rules, chemical precipitation includes hydroxide precipitation, organosulfide precipitation, and iron coprecipitation to treat FGD wastewater.

membrane systems may require pretreatment to prevent scaling and fouling by removing excess TSS, calcium, magnesium, sulfate, or organics. 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. To reduce fouling, membrane filtration systems have been designed with vortex generating blades or vibratory movement. Other systems may use a microfiltration (or ultrafiltration/nanofiltration) or chemical precipitation pretreatment step that targets scale-forming ions where FGD wastewater characteristics indicate potential fouling.

FO uses a semi-permeable membrane and differences in osmotic pressures to achieve separation. 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 uses 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 across the membrane.

EDR uses a semi-permeable membrane and differences in electrical charges to achieve separation of specific anions and cations. The first-of-its-kind domestic pilot of EDR for FGD wastewater indicates that treatment with electrodialysis reversal has continued to advance and become more available. This pilot is detailed in the 2020 Electric Power Research Institute report *FGD Wastewater Treatment Testing Using a Saltworks Flex EDR Selective (Electrodialysis Reversal System) Technology*, which found that "[t]he Flex EDR Selective pilot plant reliably operated for 61 days, 24/7, including weekends and unattended overnights." Other key findings included an average 93 percent water recovery, 98 percent uptime of continuous operations (over 1,440 hours), selective removal of chlorides, the elimination of the need for soda ash softening, "demonstrated versatility to treat wastewater of different concentrations and water chemistries with the same treatment plant," and the potential for cost savings when compared to comparable treatment systems (EPRI, 2020).

While microfiltration, ultrafiltration, and/or nanofiltration may provide sufficient pretreatment for membrane filtration systems, incorporating chemical precipitation pretreatment 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 have included some type of pretreatment (*e.g.,* surface impoundment, chemical precipitation, microfiltration) to reduce TSS and/or soften the wastewater before it enters the membrane system. Membrane systems can be configured with polishing RO systems (*e.g.,* multi-stage RO systems) to further remove pollutants from the permeate. As well, 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 concentrate 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 through another process, such as thermal system treatment (see Sections 4.1.3 and 4.1.4).

The EPA identified two full-scale domestic installations of RO and one installation in South Africa for treating wastewater in the mining industry; and four domestic membrane filtration pilot studies in the petroleum refining and agriculture industries. The EPA further identified four full-scale installations of membrane filtration in the coal-to-chemical industry in China and the textile industry in India.[20] In the steam electric power generating industry, the EPA identified 30 pilot-scale studies of membrane filtration used for FGD wastewater treatment world-wide (U.S. EPA, 2024e, 2024f) as well as 12 full-scale foreign installations for FGD wastewater (refer to Section VII.B.1 of the preamble). Some of the full-scale systems employ pretreatment before a combination of RO and FO. Others operate pretreatment followed by

[20] The EPA has limited data on the performance and configuration of the full-scale and pilot-scale membrane systems (Wolkersdorfer, 2015; U.S. EPA, 2014; CH2M Hill, 2010; ERG, 2019, 2020). These systems may include nanofiltration, microfiltration, and RO systems.

nanofiltration and RO. At least one plant uses thermal treatment to produce a crystallized salt from the concentrate stream, which is sold for industrial use. Of the 30 pilot-scale studies, the EPA is aware of one U.S. facility that is conducting a long-term pilot project of membrane filtration for treating FGD wastewater, including testing to date of a 1-GPM treatment system and a 50-GPM treatment system (U.S. EPA, 2023d).

See the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering—2024 Final Rule* memorandum for more information on pilot testing of membrane filtration technologies (U.S. EPA, 2024e).

4.1.3 Spray Evaporation

Spray evaporation technologies, which include spray dryers and other similar proprietary variations, are an example of a thermal technology that is being applied to FGD wastewater treatment. Spray dryer systems evaporate wastewater by spraying fine misted wastewater into hot gasses. The hot gases allow the wastewater to evaporate before contacting the walls of the evaporation vessel, which allows spray evaporation systems to remove TDS, TSS, or scale-forming pollutants.

For FGD application, 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 (FA) by the main particulate control equipment (*e.g.,* electrostatic precipitator or fabric filter) and disposed of in a landfill. In cases where FA is marketable, and contamination is a concern, a separate particulate control system can be operated on the flue gas slipstream to capture FGD solids alone.

Spray evaporation systems can be used in combination with other volume reduction technologies, such as membranes, to maximize the efficiency of each process. For instance, RO systems can be installed upstream of spray evaporation technologies to reduce influent flows. Concentrate from the RO system can be processed through the spray evaporation system to achieve zero discharge. To achieve zero discharge, permeate from the RO system needs to be recirculated back into plant operation as process wastewater. Another method for reducing the volume of FGD wastewater influent to a spray evaporation system may involve reconfiguring process flow to exclude non-FGD wastewater from the treatment system (if wastewater is diluted by utility water streams prior to treatment).

The EPA identified a vendor that has developed a proprietary technology that combines concepts of a brine concentrator and spray dryer to achieve zero discharge. The system, referred to as an adiabatic evaporator, 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 the concentrated wastewater is sent to a solid-liquid separator. The separated wastewater is recycled and sent back through the system, while the solids can be landfilled. An alternative configuration would be to encapsulate the separated wastewater, by mixing it with FA, and then landfilling. Pretreatment of FGD wastewater is not required, but for situations where TSS exceeds 5 percent, it may be cost-effective to operate a clarifier upstream of the evaporator to decrease solids. The vendor operated a full-scale system 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 high, and the system was replaced. Nevertheless, an adiabatic evaporator is capable of evaporating FGD wastewater using multiple thermal energy sources, including engine/turbine exhaust, a slipstream from coal-fired power plant flue gas, natural gas, or alternative fuel enclosed flare exhaust. Additionally, adiabatic evaporators can be used downstream of other volume reduction technologies, including RO, to reduce the amount of FA required for brine encapsulation.

The EPA identified three domestic installations of spray evaporation technologies treating FGD wastewater, including one installation at the Boswell Energy Center in Minnesota (U.S. EPA, 2024e; John

Wood Group PLC, 2022). The EPA also identified six installations of spray evaporation systems treating FGD wastewater outside of the U.S. (U.S. EPA, 2024e).

See the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering—2024 Final Rule* memorandum (U.S. EPA, 2024e) for more information on pilot testing of membrane filtration technologies.

4.1.4 Other Thermal Treatment Options

Thermal technologies 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; this generates a distillate stream and solid byproduct that can be disposed of in a landfill. EPA identified coal-fired steam electric power plants in China that have installed membrane treatment, followed by brine concentrators and crystallizers to treat FGD wastewater. Brine concentration followed by crystallization was evaluated as part of the 2015 rule as a possible treatment technology for the industry; see Section 7.1.4 of the 2015 TDD for a detailed description of this treatment configuration (U.S. EPA, 2015a).

Two U.S. plants have installed brine concentrator systems for FGD treatment and at least five steam electric power plants in Italy also operate this type of system for FGD wastewater (U.S. EPA, 2024e; EKPC, 2018).[21] In addition, there are two plants in China that use a combined evaporator and crystallizer for FGD wastewater treatment (U.S. EPA, 2024e).

The EPA identified one vendor that has developed a modular brine concentration technology to heat FGD wastewater and facilitate evaporation. As the wastewater boils, steam is collected, compressed, and directed into a proprietary technology that allows the thermal energy 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 water 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 encapsulated 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 steam electric power plants between 2015 and 2017.

4.1.5 Encapsulation

Encapsulation is a technology that can be used to eliminate FGD wastewater discharge. It uses chemical reactions and/or absorption processes to bond materials together so that wastewater is incorporated into the solid material. This process is also referred to as solidification. This technology has been used by plants operating inhibited oxidation scrubber systems, where byproducts from the scrubber are mixed with FA and lime to produce a non-hazardous landfillable material. This same approach has been tested with pretreated FGD wastewater by mixing concentrated FGD wastewater with combinations of FA, hydrated lime, sand, and/or Portland cement to encapsulate contaminants. Tests of these materials have

[21] Two additional plants in the U.S. previously installed thermal treatment for FGD wastewater but are retiring or refueling by 2028; one plant previously installed thermal treatment and later installed a different treatment system (U.S. EPA, 2024e; ERG, 2020a). One additional plant in Italy previously installed thermal treatment for FGD wastewater but no longer operates the system (U.S. EPA, 2024e).

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).

Encapsulation can be used alone or in combination with other treatment technologies. For instance, it can be incorporated on reduced volumes of the concentrated stream downstream of a membrane and/or thermal system. As described in Section 4.1.3, it can also be implemented downstream of spray or adiabatic evaporation technologies that achieve only partial evaporation and produce concentrated wastewater streams.

4.2 BA Handling Systems and Transport Water Management and Treatment Technologies

The EPA reviewed BA handling systems—operated at coal-fired steam electric power plants or marketed by BA handling vendors—that are designed to minimize or eliminate the discharge of BA transport water. Many plants have installed or are installing BA handling systems that minimize or eliminate the discharge of BA transport water. The BA handling technologies evaluated by the EPA and described in this section include mechanical drag systems, remote mechanical drag systems, compact submerged conveyors (CSCs), and mobile mechanical drag systems.

As part of previous rulemaking efforts in 2015 and 2020, the EPA also evaluated types of dry ash handling systems: dry mechanical conveyors and pneumatic systems (*i.e.,* dry vacuum or pressure systems). See the 2015 TDD and 2020 Supplemental TDD (U.S. EPA, 2015a; U.S. EPA, 2020).

4.2.1 Mechanical Drag System

A mechanical drag system collects BA 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 BA 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 BA toward the far end of the bath. The chains then move up an incline, dewatering the BA by gravity and draining the water back to the trough. Because the BA falls directly into the water bath from the bottom of the EGU and the drag chain moves constantly on a loop, BA removal is continuous. The dewatered BA is often conveyed to a nearby collection area, such as a small bunker outside the EGU building, from which it is loaded onto trucks and either sold or transported to a landfill. See Section 7.3.3 of the 2015 TDD for more specific system details (U.S. EPA, 2015a).

The mechanical drag system does generate some wastewater (*i.e.,* residual water that collects in the storage area as the BA 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)).[22]

This system may not be suitable for all EGU configurations and may be difficult to install if there is limited space below the EGU.[23] These systems cannot combine and collect BA 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 BA fragments falling directly onto the drag chain.

[22] 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 BA from the boiler; the conveyor is the transport mechanism. Therefore, any water leaving with the BA does not fall under the definition of "bottom ash transport water," but rather is a low-volume waste.

[23] 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.

4.2.2 Remote Mechanical Drag System

Remote mechanical drag systems collect BA using the same operations and equipment as wet-sluicing systems at the bottom of the EGU. However, instead of sluicing the BA directly to a surface 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 to enable recycling BA transport water back to the system. 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 (U.S. EPA, 2015a).

Plants converting their current BA 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 BA.

Because of the chemical properties of BA transport water, some plants may need to add flocculant or polymer to aid in the settling of fines to prevent potential plugging of the sluice pipes. Other 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, chemical addition, or an RO membrane (as described in the EPA's cost methodology in Section 5) depending on the BA transport water characteristics and materials of construction.

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 needs less maintenance than the mechanical drag system because the BA particles entering it have already been through the grinder prior to sluicing.

4.2.3 CSC

A CSC, also referred to as submerged grind conveyor, collects BA from the bottom of the EGU. A CSC uses existing equipment—BA hoppers or slag tanks, the BA gate, clinker grinders, and a transfer enclosure—to remove BA from the hopper continuously. From the bottom of the EGU, BA 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 BA up an incline, away from the EGU. Because the transport mechanism is the conveyor instead of water, CSCs do not generate BA transport water.[24] The dewatered BA is transferred to one or more additional conveyors, which transports it to a BA silo or bunker where the BA 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 BA 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 could 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 places with insufficient space for the larger mechanical drag system conveyors.

A CSC can be isolated from the hopper using the existing transfer enclosures to perform maintenance while the EGU remains online (made possible by the BA storage capacity of the hopper). It is also possible for some plants to install parallel conveyors for redundancy (ERG, 2020b, 2020c, 2020d, 2020e).

[24] Like mechanical drag systems, CSCs are considered a dry handling technology, because they do not use water as the transport mechanism.

For plants that can 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, than for other under-the-EGU BA handling systems. However, because a CSC serves just one EGU, the more EGUs a plant has, the less economical this technology becomes.

The EPA is aware of at least five plants that have installed and are operating CSC systems in the United States. The EPA understands that these facilities do not have vertical space constraints under the EGUs.

4.2.4 Mobile Mechanical Drag System

A mobile mechanical drag system is a BA transport water dewatering unit—similar to a remote mechanical drag system—with an additional clarification system (U.S. EPA, 2022). This technology is not intended to be set on a permanent location, which reduces capital costs associated with permanent infrastructure. Depending on the facility, a mobile mechanical drag system can either remain on a truck or be installed on facility grounds. From the mechanical drag system, BA transport water is taken to a mobile clarifier and polished to a level suitable for recirculation. This mixture is sent up an incline, dewatered, and discharged.

The mobile clarifiers are typically equipped with lamella separators, polymer addition, and mobile chemical injection systems, including coagulant (typically ferric chloride) and flocculant for solids removal and caustic and acid injection for pH control. Typically, thickened sludge from the mobile clarifier is pumped back to the mechanical drag unit, with the coarse particulates acting as ballast to assist the sludge up the ramp to the mechanical drag system. The fines from the underflow of the clarifier can be pumped to a mobile belt filter press to make filter cake.

In addition to reducing capital costs, benefits of mobile systems include reduced construction costs, a smaller footprint compared to other BA treatment options, increased flexibility, minimal invasion to the facility's existing systems, manual controls to reduce complexity of control system tie-in, and the ability to serve as a recirculation system.

Mobile mechanical drag systems may have relatively higher operation and maintenance costs: the system is often a single remote mechanical drag system and an upset condition may require the unit to be shut down, and nonpermanent infrastructure (such as flexible HDPE piping and hose connections) lacks the robust nature of carbon steel or ballast line materials.

The EPA is aware of one installation of a mobile system at a plant serving two coal-fired units and a full-scale pilot demo at a facility using a mobile system combined with a hydrocyclone vibrating screen to treat dewatering surface impoundment water.

4.3 CRL Treatment Technologies and Management Practices

In promulgating the 2015 rule, the EPA determined that CRL from landfills and surface impoundments includes similar types of constituents as FGD wastewater, albeit at potentially lower concentrations and smaller volumes. Based on this characterization of the wastewater and knowledge of treatment technologies, the EPA determined that certain treatment technologies identified for FGD wastewater could also be used to treat CRL from landfills and surface impoundments containing combustion residuals.

In support of the 2015 rule, the EPA identified facilities using surface impoundments, biological treatment, and constructed wetlands to treat CRL, sometimes commingled with FGD wastewater. The EPA also identified facilities using other management practices to manage CRL, including recycling the wastewater in other plant operations or for moisture conditioning of FA. This section describes treatment technologies the EPA considered for the treatment of CRL as part of this 2024 final rule, including technologies already being used by the industry.

4.3.1 Chemical Precipitation

In a chemical precipitation wastewater treatment system, chemicals are added to the wastewater to alter the physical/chemical state of dissolved and suspended solids to help precipitate, settle, and remove them. The specific chemical(s) used depends on the type of pollutant requiring removal. Steam electric power plants using chemical precipitation systems to treat FGD wastewater may include stages of hydroxide (lime), iron, and organosulfide addition, as well as clarification stages. Plants may either add all three chemicals to a single reaction tank or add the chemicals to separate tanks. Plants operating separate tanks typically target different pH set points within each tank for optimal precipitation of certain metals. Similar strategies may be applied to treat CRL, since this wastestream includes similar constituents as FGD wastewater.

In a hydroxide precipitation system, plants add lime (calcium hydroxide) to elevate the pH of the wastewater to a designated set point, helping precipitate metals into insoluble metal hydroxides that can be removed by settling or filtration. Sodium hydroxide can also be used in this type of system, but it is more expensive than lime and, therefore, not as common in the industry.

Plants use iron coprecipitation to increase the removal of certain metals in a hydroxide precipitation system. Steam electric power plants typically use ferric chloride to coprecipitate additional metals and organic matter. The ferric chloride also acts as a coagulant, forming a dense floc that enhances settling of the precipitated metals in downstream clarification stages.

Organosulfide precipitation systems use organosulfide chemicals (*e.g.,* trimercapto-s-triazine [TMT], Nalmet® 1689, MetClear™, sodium sulfide) to precipitate and remove heavy metals. Plants may test several organosulfide chemicals to determine which one is most appropriate for their treatment systems. Organosulfide precipitation can also optimize removal of metals with lower solubilities, such as mercury, more effectively than hydroxide precipitation or hydroxide precipitation with iron coprecipitation. EPA sampling data show that adding organosulfide to the FGD wastewater can reduce dissolved mercury concentrations to less than 10 parts per trillion (ERG, 2012). Organosulfide precipitation is more effective than hydroxide precipitation in removing metals with low solubilities because metal sulfides have lower solubilities than metal hydroxides. Due to the relatively low costs of hydroxide precipitation, plants usually use hydroxide precipitation first to remove most of the metals, and then organosulfide precipitation to remove the remaining low solubility metals. This configuration overall requires less organosulfide, therefore reducing costs.

The EPA's data demonstrate that well-operated systems maintain their chemical precipitation effluent concentrations because they actively monitor target metals, allowing them to adjust the operation of the chemical precipitation system as necessary. Some plants actively monitor the influent to the treatment system and adjust chemical addition in an equalization tank with a 24-hour holding time as the first step in the treatment system.

The EPA identified two facilities using chemical precipitation treatment systems for CRL. See Section 7.1.2 in the 2015 TDD for more specific chemical precipitation system design details (U.S. EPA, 2015a).

4.3.2 Biological Treatment

Some plants use the same biological wastewater treatment systems to treat both FGD wastewater and CRL, in some cases as a combined stream. Microorganisms consume biodegradable soluble organic contaminants and bind much of the less soluble fractions into floc. Pollutant concentrations may be reduced aerobically, anaerobically, and/or by using anoxic zones to remove metals and nutrients. The EPA identified two facilities using fixed-film bioreactors that reduce selenium and nitrate/nitrite to treat CRL. See Section 4.1.1 for more details on the LRTR system specific to FGD wastewater treatment, which can also be used to treat CRL.

4.3.3 Membrane Filtration

See Section 4.1.2 for a description of membrane treatment technologies, which can also be used to treat CRL from landfills and surface impoundments containing combustion residuals. There are three treatment technology vendors with full-scale domestic and foreign installations treating non-CCR landfill leachate using membrane filtration that discharge the permeate (U.S. EPA, 2022a, 2024e). One membrane filtration vendor has conducted a domestic pilot study on FA leachate (U.S. EPA, 2024e).

4.3.4 Spray Evaporation

See Section 4.1.3 for a description of spray evaporation treatment technologies that can also be used to treat CRL. There are two domestic installations by one technology vendor operating membrane filtration followed by spray evaporation at municipal landfills; this vendor also conducted a domestic pilot study treating CCR leachate with membrane filtration followed by spray evaporation. See the EPA's *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering—2024 Final Rule* memorandum for more information (U.S. EPA, 2024e).

4.3.5 Other Thermal Treatment Options

See Section 4.1.4 for a description of other thermal treatment technologies that can also be used to treat CRL from landfills and surface impoundments containing combustion residuals. One technology vendor operates these systems at municipal landfills, and a second vendor has conducted a foreign pilot study on municipal landfill leachate that included membrane filtration followed by a combined brine concentrator and crystallizer (U.S. EPA, 2024e).

4.3.6 Management Strategies and Reuse

In promulgating the 2015 rule, the EPA also identified steam electric power plants using other types of management strategies for CRL from landfills and surface impoundments (U.S. EPA, 2015a):

- As of 2009, 24 plants collect combustion residual landfill or surface impoundment CRL and use it as water for moisture conditioning dry FA prior to disposal or dust control around dry unloading areas and landfills.
- As of 2009, the EPA identified five plants that use collected CRL from landfills or surface impoundments as truck wash and route it back to surface impoundments.
- As of 2009, approximately 40 percent of plants collect CRL from surface impoundments and recycle it directly back to the surface impoundments from which it was collected.

4.4 Legacy Wastewater Treatment Technologies and Management Practices

Legacy wastewater can be comprised of FGD wastewater, BA transport water, FA transport water, CRL, gasification wastewater and/or FGMC wastewater generated before the "as soon as possible" date that more stringent effluent limitations from the 2015 or 2020 rules would apply. Discharges of legacy wastewater may occur through an intermediary source (*e.g.,* a tank or surface impoundment) or directly into a surface waterbody, with the vast majority of legacy wastewater currently contained in surface impoundments. The EPA determined that the technologies described in the following subsections, which can also treat FGD wastewater, can be applied to treat this type of legacy wastewater.

The EPA recognizes that the characterization of legacy wastewater may differ within the layers of a CCR surface impoundment as it is dewatered and prepared for closure. Therefore, treatment requirements may change as closure continues. Wastewater characteristics may also differ across CCR surface impoundments due to different types of fuels burned at the plant, duration of impoundment operation, and ash type. The list of treatment technologies identified for legacy wastewater above are all applicable to all legacy wastewaters; however, treatment may require a combination of those technologies (*e.g.,* chemical precipitation and membrane filtration).

In addition, solids dewatering is necessary to dredge CCR materials from the surface impoundment. Mobile dewatering systems are typically self-contained units on a trailer, allowing for the entire system to be easily moved on site and off site. Legacy wastewater from a holding area (*e.g.,* pit, pond, collection tank) is pumped through a filter press to generate a filter cake and wastewater stream. A shaker screen can be added to the treatment train to remove larger particles prior to the filter press. Furthermore, the filter press can be equipped with automated plate shifters to allow solids to drop from the end of the trailer directly into a loader or truck. The resulting wastestream may be further treated to meet any discharge requirements.

4.4.1 Chemical Precipitation

See Section 4.3.1 for a description of chemical precipitation technologies that can also be used to treat this type of legacy wastewater.

4.4.2 Biological Treatment

See Sections 4.1.1 and 4.3.2 for descriptions of biological treatment technologies that can also be used to treat this type of legacy wastewater. Furthermore, Section 7.1.3 of the 2015 TDD and Section 4.1.1 of the 2020 Supplemental TDD include additional biological treatment system design details (U.S. EPA, 2015a; U.S. EPA, 2020).

4.4.3 Zero Valent Iron

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 this type of legacy 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. The quantity of ZVI required and the number of reaction vessels can be varied based on the composition and amount of wastewater being treated.

Treatment configurations may include chemical precipitation followed by ZVI treatment and may also include pretreatment to partially reduce influent nitrate concentrations. 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.

The 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.[25] In addition to the seven FGD pilots of ZVI, the EPA observed ZVI technology used to treat ash transport water during surface impoundment dewatering at a plant. In this application, the surface impoundment water was first treated by RO 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 surface impoundments, and these pollutants were effectively removed by the ZVI process (ERG, 2019a). A similar treatment train has been suggested for FGD wastewater: chemical precipitation followed by RO membrane filtration, with the membrane reject stream sent to a ZVI stage consisting of three reactors in series. As with the treatment

[25] The 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 an RO membrane system to target selenium removal.

system for the surface impoundment, the RO permeate and ZVI effluent would be discharged (unless the RO permeate was reused within the plant).

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 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.

4.4.4 Membrane Filtration

See Section 4.1.2 for a description of membrane treatment technologies that can also be used to treat this type of legacy wastewater.

4.4.5 Thermal Treatment

See Sections 4.1.3 and 4.1.4 for a description of thermal treatment technologies, including spray evaporation, that can also be used to treat this type of legacy wastewater.

4.4.6 Encapsulation

See Section 4.1.5 for a description of encapsulation technologies that can also be used to treat this type of legacy wastewater.

4.4.7 Other Emerging Technologies

See Section 4.1.6 of the 2020 Supplemental TDD for descriptions of emerging technologies for FGD wastewater treatment that can also be applied to treat this type of legacy wastewater (U.S. EPA, 2020). These emerging technologies include electrodialysis reversal and RO technology, closed-loop mechanical vapor recompression, and distillation-based thermal transfer systems.

5. Engineering Costs

For the 2024 final rule, the U.S. Environmental Protection Agency (EPA) estimated compliance costs for flue gas desulfurization (FGD) wastewater; bottom ash (BA) transport water; combustion residual leachate (CRL) from landfills and surface impoundments; and legacy wastewater. These estimates further develop the estimated costs from the 2015 and 2020 rules. Section 9 of the 2015 TDD presents the EPA's methodology for estimating compliance costs for FGD wastewater, BA transport water, and CRL. Section 5 of the 2020 Supplemental TDD describes the EPA's cost estimates for FGD wastewater and BA transport water. Here, the EPA is presenting cost estimates for baseline compliance, post-compliance, and incremental costs, defined as follows:

- *Baseline compliance costs.* The EPA based its analysis on a modeled baseline that reflects the full implementation of the 2020 rule, the expected effects of announced retirements and fuel conversions, and the impacts of relevant final rules affecting the power sector. As such, the baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from changes to the existing 2020 limitations and standards. For more information, see the *Regulatory Impact Analysis for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA) (U.S. EPA, 2024g). For FGD wastewater and BA transport water, the baseline compliance costs anticipate that plants will have met the requirements of the 2020 rule; for CRL and legacy wastewater, baseline compliance costs consider current treatment in place.
- *Post-compliance costs*. Post-compliance costs are costs for plants to comply with effluent limitations based on the technologies considered in the 2024 rule technology options. The EPA estimated post-compliance costs with the expectation that all steam electric power plants subject to the requirements of the 2024 rule will install and operate wastewater treatment and pollution prevention technologies equivalent to the technology bases for the regulatory options.
- *Incremental costs*. Incremental costs reflect the difference between the baseline compliance costs and 2024 rule post-compliance costs for each regulatory option.

The EPA's compliance cost estimates include the following components:

- *Capital costs (one-time costs).* Capital costs comprise the direct and indirect costs associated with purchasing, delivering, and installing pollution control technologies. Capital cost elements include purchased equipment and freight, equipment installation, buildings, site preparation, engineering costs, construction expenses, contractor's fees, and contingencies.
- *Annual operation and maintenance (O&M) costs (incurred every year).* Annual O&M costs comprise all costs related to operating and maintaining the pollution control technologies for a period of one year. O&M cost elements 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.
- *Other one-time or recurring costs.* In some cases, the technology options may also result in costs that recur less often than annually (*e.g.,* three-year recurring costs for equipment replacement) or one-time costs other than capital investment (*e.g.,* one-time cost to consult with an engineer).

The EPA updated its industry profile as follows:

- The EPA began by updating its profile to reflect retirements of electric generating units (EGUs) that will occur by December 31, 2028, for the FGD wastewater and BA transport water populations.
- The EPA also removed any EGUs that will have converted to a non-coal fuel source by December 31, 2028, for FGD wastewater and BA transport water populations.

- Through August 2023, the EPA incorporated notices of planned participation (NOPPs) for any plants that opted into the Voluntary Incentives Program (VIP) for FGD wastewater.
- For CRL, the EPA removed plants that retired all coal-fired EGUs by December 31, 2023. The EPA did not remove EGUs that converted to different fossil fuel sources (*e.g.,* gas-fired) from the CRL population. These EGUs, which previously burned coal and generated coal combustion residuals (CCRs) that were disposed of in landfills and surface impoundments, remained in the population because the corresponding plant is still operating. The EPA updated its industry profile to include plants operating coal-fired EGUs or refueled EGUs that have an open or closed (retired) waste management unit (*i.e.,* landfill or surface impoundment) that discharges CRL.[26] Based on the applicability of 40 CFR 423, these plants and CRL are still subject to the guidelines. See Section 5.3.1 for details on how the EPA developed the CRL population.
- The EPA incorporated retired and operating plants with surface impoundments that are open (*i.e.,* have not initiated the closure process under the CCR regulations) using information from the Office of Land and Emergency Management (OLEM) and power company CCR websites, as described in Section 2.5.

The remainder of this section describes the EPA's methodology for estimating baseline compliance costs, post-compliance costs, and incremental costs by wastestream, as well as industry-level compliance costs for the 2024 rule.

5.1 FGD Wastewater

For the 2024 final rule, the EPA estimated costs for plants to install and operate four technologies: chemical precipitation followed by low residence time reduction (CP+LRTR), membrane filtration, spray dryer evaporator (SDE), and thermal evaporation.

For CP+LRTR, the EPA included the following treatment components for FGD wastewater, consistent with the 2020 rule methodology:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems (lime, organosulfide, ferric chloride, and polymers).
- LRTR treatment equipment (anoxic/anaerobic bioreactor, flow control, backwash supply, and storage tanks).
- LRTR chemical feed system for nutrients.
- Pretreatment system for nitrate/nitrite (for plants with nitrate/nitrite concentrations above 50 milligrams per liter [mg/L]).
- Heat exchanger.
- Ultrafilter.
- Compliance monitoring (including sample collection and analysis).
- Solids handling (sludge holding tank and filter press).
- Transportation and disposal of solids in a landfill.

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[26] For a new subcategory of CRL, the EPA identified potential discharges of unmanaged CRL, which the EPA is defining in this rule to mean the following: (1) discharges of CRL that the permitting authority determines are the functional equivalent of a direct discharge to Waters of the United States (WOTUS) through groundwater, or (2) discharges of CRL that has leached from a waste management unit into the subsurface and mixed with groundwater prior to being captured and pumped to the surface for discharge directly to a WOTUS.

For membrane filtration, the EPA included the following FGD wastewater treatment components, consistent with the 2020 rule methodology:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems (lime, organosulfide, ferric chloride, and polymers).
- Membrane filtration treatment equipment (membrane filtration, reverse osmosis [RO], and storage tanks).
- Additional fly ash (FA) purchase (if plant was identified as having an FA deficit).[27]
- Brine encapsulation.
- Transportation and disposal of solids in a landfill.

For SDE, the EPA included the following FGD wastewater treatment components:

- Pretreatment using membrane filtration (for flows greater than 150 gallons per minute [GPM] only) (includes membrane filtration, RO, and storage tanks).
- SDE equipment.
- Transportation and disposal of solids in a landfill.

For thermal evaporation treatment of FGD wastewater, the EPA included the following treatment components:

- Membrane filtration treatment equipment (for preconcentration, as needed).
- Brine concentration and encapsulation or crystallization equipment.
- Transportation and disposal of solids in a landfill.

Section 5.1.1 describes the cost inputs and the methodology for updating the FGD wastewater flow rates from the 2020 rule. Sections 5.1.2, 5.1.3, 5.1.4, and 5.1.5 present the EPA's methodology for estimating costs for LRTR, membrane filtration, SDE, and thermal evaporation, respectively. Section 5.1.6 presents the EPA's methodology for determining the least cost zero-discharge technology option for FGD wastewater.

5.1.1 FGD Cost Calculation Inputs

To estimate plant-level baseline and post-compliance costs of implementing FGD wastewater treatment technologies, the EPA developed cost calculation databases. These databases combine plant-specific input values, including wastewater flow rates and baseline treatment technology, with the relationships between costs and FGD flow rates described in Sections 5.1.2, 5.1.3, and 5.1.4 to estimate baseline and post-compliance costs for each plant (ERG, 2024, 2024a). For the 2024 final rule, the EPA used input data compiled from the 2015 and 2020 rules—including Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data—and updated these data using new information gathered from industry (see Section 2). This section describes the updates to cost inputs from the 2020 rule.

Population

The EPA identified coal-fired power plants that discharge FGD wastewater to surface water or a publicly owned treatment works (POTW) and that are not expected to retire or convert fuel sources by December 31, 2028. The EPA started with the population of plants from the 2020 rule and updated the population based on industry-provided data and new publicly available data on operational changes. The EPA also

[27] Refer to the *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* memorandum for more information (U.S. EPA, 2024h).

compiled a list of the EGUs at these plants that discharge FGD wastewater, keeping in mind that some plants retire or convert individual EGUs and not the entire plant.

Flow Rate

For each plant, the EPA estimated two FGD wastewater flow rates: the FGD purge flow rate (the typical amount of wastewater from the FGD scrubber that is sent to FGD wastewater treatment) and the FGD optimized flow rate (a rate that considers a reduction in FGD wastewater purged from the system, where equipment metallurgy is able to accommodate increased chloride concentration in the FGD system). As in the 2020 rule, the EPA used the FGD purge flow rate to calculate capital costs to ensure that the installed treatment technologies would be able to accommodate the maximum possible FGD flow. The EPA also concluded that plants would optimize the FGD purge flow rate to reduce the flow that must be treated, and thereby reduce overall O&M compliance costs. As flows are recycled through the FGD system, chloride concentrations increase; therefore, when calculating an optimized flow rate, the EPA considered plant-specific constraints such as maximum design chloride concentrations and operating chloride concentrations for the FGD systems.

For the 2024 rule, the EPA largely used plant-specific FGD wastewater flows consistent with the 2020 rule (U.S. EPA, 2020). The EPA identified some facilities where changes to plant operations warranted updates to FGD wastewater flow rates. At plants where some, but not all, EGUs were designated for retirement or fuel conversion before December 31, 2028, the EPA adjusted FGD wastewater flow rates (purge and optimized) to remove flow for these EGUs. The EPA also incorporated any flow rate updates received in the 2023 proposed rule public comments. Refer to the *Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings – 2024 Final Rule* memorandum for a summary of these updates (U.S. EPA, 2024i).

Baseline Treatment Technology

For this cost analysis, the EPA assumed that plants subject to the FGD wastewater discharge requirements in the 2020 rule would install the treatment technology basis defined for the 2020 rule. If a plant opted into the 2020 rule VIP, then the EPA assumed membrane filtration as the baseline treatment technology. For all other FGD wastewater discharges, the EPA assumed CP+LRTR baseline treatment technology. Table 8 outlines the baseline scenarios for the plants included in the EPA's 2024 analyses and the corresponding estimated compliance costs.

Table 8. 2024 Rule FGD Wastewater Technology Bases

2024 Technology Option Evaluated	2020 Rule Subcategory [a]	2024 Baseline Treatment Technology	Estimated Incremental Capital Compliance Cost	Estimated Incremental O&M Compliance Cost
Zero discharge	VIP	Membrane filtration	Costs are equal to zero	Costs are equal to zero
	All other FGD wastewater discharges	CP+LRTR	Costs for membrane filtration (no CP costs) or SDE	Costs for membrane filtration (no CP costs) or SDE, minus LRTR [b]

a—The EPA did not evaluate costs associated with the 2020 rule FGD high-flow subcategory because the one applicable plant is scheduled to retire its coal-fired EGUs by December 31, 2028.

b—The EPA estimated O&M costs as the incremental costs between operating and maintaining an LRTR system (see Section 5.1.2) and operating and maintaining a membrane filtration system (see Section 5.1.3) or SDE system (see Section 5.1.4). For the zero-discharge technology option, the EPA assumed plants will stop operating the LRTR portion of the system. The EPA also assumed that plants installing membrane filtration specifically will continue operating the CP portion as pretreatment.

Landfill Data

The EPA used data from the Steam Electric Survey and public permit data to determine if each plant in the FGD wastewater population has a lined CCR landfill (active or inactive) for disposal of treatment residuals. For the 2024 final rule, the EPA updated this information to match the population used for CRL costs (see Section 0 for more information). Plants identified as having a landfill incurred compliance costs for on-site transportation and disposal of treatment residuals; all other plants incurred compliance costs for off-site transportation and disposal.

5.1.2 Cost Methodology for LRTR

As described in the RIA, the EPA's baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from changes to the existing 2020 limitations and standards. Therefore, the EPA assumed that plants have come into compliance with the 2020 rule, and all plants in the 2024 final rule analysis are assumed to have installed CP+LRTR, membrane filtration, or equivalent treatment. Since both technology bases include CP, the EPA did not estimate additional compliance costs for CP treatment. Further, since the EPA assumes that all plants that did not opt into the 2020 rule VIP have installed LRTR, no plants will incur incremental capital costs to install this technology. The EPA incorporated LRTR O&M as a cost savings for the zero-discharge technology option for non-VIP plants.

The EPA updated the LRTR O&M cost curves by adjusting the cost indexing values to 2023 dollars using data from the RSMeans Historical Cost Index (RSMeans, 2023). The 2021 cost index value was 238.3, and the 2023 cost index value was 318.8. The EPA multiplied the cost curve components by the ratio of these indexes (the 2023 index divided by the 2021 index equals 1.338), resulting in the equations presented below. To determine plant-specific nitrate/nitrite concentrations and consequently which LRTR cost curve to use, the EPA used sampling data from the 2015 rule analytical database (ERG, 2015, 2015a) and the Steam Electric Survey (U.S. EPA, 2015). Plants with nitrate/nitrite concentrations above 50 mg/L in untreated FGD wastewater require nitrate/nitrite pretreatment and are considered "high nitrates."

The resulting adjusted cost curves are as follows:

$$\text{LRTR O\&M cost – low nitrates (2023\$/year)} = 1.08 \times \text{FGD flow (gallons per day [GPD])} + 479{,}404$$

$$\text{LRTR O\&M cost – high nitrates (2023\$/year)} = 1.61 \times \text{FGD flow (GPD)} + 506{,}970$$

Similar to the 2020 and 2015 rules, the EPA estimated compliance monitoring costs to account for sampling labor and materials as well as the costs associated with sample preservation, shipping, and analysis for the pollutants selected for regulation (arsenic, mercury, nitrate/nitrite, and selenium for CP+LRTR). The EPA also updated the compliance monitoring cost to 2023 dollars, resulting in an amount of $110,968 for each plant.

The EPA estimated LRTR plant-level O&M cost savings as follows:

- For plants opting in to the 2020 rule VIP, the EPA estimated zero cost savings.
- For one plant that installed a CP system capable of meeting the 2020 rule's best available technology economically achievable (BAT) limitations, the EPA estimated LRTR O&M cost savings as compliance monitoring only ($110,968).
- For all other plants, the EPA estimated LRTR O&M cost savings using the LRTR O&M cost equations described above with the plant-specific FGD optimized flow rate.

5.1.3 Cost Methodology for Membrane Filtration

As with the LRTR cost methodology, the EPA did not estimate additional costs for CP pretreatment for the membrane filtration cost methodology, as plants are assumed to have come into compliance with the

2020 rule and already have this treatment in place. The EPA updated the membrane filtration cost curves by escalating them to 2023 dollars using the method described in Section 5.1.2.

The resulting curves are as follows:

membrane filtration capital cost with on-site transport/disposal (2023$) =
57.2 × FGD flow (GPD) + 2,388,069

membrane filtration O&M cost with on-site transport/disposal (2023$/year) =
8.41 × FGD flow (GPD) + 681,426

membrane filtration capital cost with off-site transport/disposal (2023$) =
52.8 × FGD flow (GPD) + 2,438,706

membrane filtration O&M cost with off-site transport/disposal (2023$/year) =
16.9 × FGD flow (GPD) + 681,825

In addition, plants that indirectly discharge receive an O&M cost savings for no longer paying annual fees for a POTW to accept and treat their FGD wastewater. The EPA identified one plant in the FGD wastewater population as an indirect discharger and assigned this plant $1.5M in O&M cost savings, the cited discharge fees in the utility's comment letter (EPA-HQ-2009-0819-10083-A1).

The EPA used the following equations to estimate the amount of brine and lime or other fillers to be disposed of, based on the EPA's *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* (U.S. EPA, 2024h):

brine (tons) = brine flow (GPD) × density of brine (lb/gal) × 365 (days/year) × 0.0005 (ton/lb)

Where:

brine flow	=	FGD optimized flow (GPD) times brine production rate, 30%.
density of brine	=	8.84 pounds per gallon (lb/gal).

lime or other fillers (tons) = brine (tons) × ratio of lime or other fillers to brine

Where:

ratio of lime or other fillers to brine	=	Ratio by mass percentage of lime or other fillers to brine in encapsulation recipe, 0.28.

The EPA then summed the total solids for disposal as the following:

solids for disposal (tons) = brine (tons) + lime or other fillers (tons)

To estimate compliance costs for transporting and disposing of these solids, the EPA used equations from the 2015 rule and escalated them to 2023 dollars. For the on-site transportation capital cost and on-site disposal O&M cost equations, the EPA used RSMeans indexes to escalate from 2009 dollars with a ratio of 1.747; for all other transportation and disposal cost equations, the EPA used RSMeans indexes to escalate from 2011 dollars with a ratio of 1.717 (RSMeans, 2023). Because the membrane filtration capital and O&M cost curves already include transportation and disposal costs, the EPA subtracted out a percentage of transportation and disposal costs to avoid double counting. To protect confidential business information (CBI), the EPA estimated this amount as 25 percent.

The resulting equations are as follows:

transportation capital cost (on-site) (2023$) = $50.40 × solids for disposal (tons) × 0.75

transportation O&M cost (on-site) (2023$/year) = $5.59 × solids for disposal (tons) × 0.75

disposal O&M cost (on-site) (2023$/year) = $14.04 × solids for disposal (tons) × 0.75

transportation O&M cost (off-site) (2023$/year) = $15.85 × solids for disposal (tons) × 0.75

disposal O&M cost (off-site) (2023$/year) = $70.37 × solids for disposal (tons) × 0.75

For any plants with an FA deficit, as described in the *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* (U.S. EPA, 2024h), the EPA supplemented the membrane filtration costs with the cost to purchase additional FA on an annual basis using the deficit of ash in tons: $35.49/ton. For plants with this FA deficit, the EPA also supplemented the transportation and disposal costs for brine and lime or other fillers with the cost to transport and dispose of this additional FA, using the equations described above with a factor of 1 (instead of 0.75).

In the 2024 final rule, the EPA is providing one year of flexibility to allow for membrane filtration permeate discharge as long as the plant reports monitoring data to a publicly available website. Refer to the *Membrane Monitoring Cost Methodology* and the *Membrane Recordkeeping and Reporting Cost Methodology* for additional information (U.S. EPA, 2024j, 2024k). The one-time plant-level cost would apply during the first year of membrane filtration operation, for a total of $152,374.

The EPA estimated plant-level membrane filtration costs as follows:

- For plants opting in to the 2020 rule VIP, the EPA estimated zero capital, zero O&M, and zero one-time costs.
- For all other plants with FGD wastewater discharges, the EPA estimated plant-specific capital, O&M, and one-time costs.
    - The EPA estimated capital costs for membrane filtration using the capital cost equations described above and the FGD purge flow rate. The EPA also estimated transportation capital costs (on-site only) using the FGD purge flow rate and summed this with the membrane filtration capital cost (where applicable).
    - The EPA estimated O&M costs as the difference between LRTR O&M costs and membrane filtration O&M costs, using the FGD optimized flow rate. All plants are assumed to be currently operating LRTR systems that they will replace with membrane systems for this technology option. To estimate this difference, the EPA estimated LRTR O&M costs using the equations in Section 5.1.2 and estimated membrane O&M costs using the equations discussed in this section (including transportation and disposal O&M costs and FA purchase O&M costs). O&M costs for the membrane filtration technology option were calculated as the difference between LRTR and membrane filtration values. The EPA also accounted for O&M cost savings for the one indirect discharger identified.
    - The EPA estimated the same one-time cost for all plants for monitoring and recordkeeping ($152,374).

5.1.4 Cost Methodology for SDE

The EPA identified several vendors using a similar type of technology to evaporate wastewater by spraying fine misted wastewater into hot gases. The EPA solicited information including costs, performance data, and treatment system configuration details from Heartland, General Electric, Mitsubishi, and Ljungström. Using data from each vendor, the EPA developed separate relationships for capital costs (*e.g.,* purchased equipment and freight, equipment installation, buildings, site preparation, engineering costs, construction expenses, contractor's fees, and contingency) and O&M costs (*e.g.,* operating labor, maintenance labor, maintenance materials, chemical purchases, energy requirements, and residuals disposal). The EPA developed comparable costs for the technologies for all vendors by evaluating the cost data provided by each vendor and augmenting those data with costs for missing components. See the *Spray Dryer Evaporator Cost Methodology* for a summary of the vendor-specific data (U.S. EPA, 2022b).

Based on feedback from SDE vendors, it is generally more cost effective to implement volume reduction (i.e., membrane filtration pretreatment) on wastewater streams above 200 GPM. As well, some vendors noted that some costs were only valid up to 150 GPM; therefore, the EPA estimated costs for spray evaporation only for small wastewater flows (≤ 150 GPM) and costs for volume reduction followed by spray evaporation for larger flows (>150 GPM). For each vendor, the EPA estimated both capital and O&M costs of an SDE treatment system over a range of FGD wastewater flows, from 0.69 GPM to 1,000 GPM. Consistent with feedback from vendors, the SDE treatment system for flows from 0.69 GPM to 150 GPM included only SDE and solids handling, while the SDE treatment system for flows from greater than 150 GPM to 1,000 GPM included preconcentration using membrane filtration followed by spray evaporation treatment of the brine.

Based on values from all four vendors at various flows within the range, the EPA calculated the average cost for capital and O&M costs. See Section 3 of the *Spray Dryer Evaporator Cost Methodology* for a summary of average costs by flow (U.S. EPA, 2022b). The EPA used the line of best fit derived from these average cost data points to develop capital and O&M cost equations based on wastewater flow (refer to Section 4 of the *Spray Dryer Evaporator Cost Methodology*). The EPA then escalated these cost equations from 2021 to 2023 dollars using a factor of 1.338.

The resulting equations are as follows:

Capital and O&M costs assuming on-site solids management for flows up to 150 GPM:

spray evaporation with on-site solids management – capital costs (2023$) = 128 × flow (GPD) + 14,717,560

spray evaporation with on-site solids management – O&M costs (2023$/year) = 12.1 × flow (GPD) + 144,207

Capital and O&M costs assuming off-site solids management for flows up to 150 GPM:

spray evaporation with off-site solids management – capital costs (2023$) = 124 × flow (GPD) + 14,717,560

spray evaporation with off-site solids management – O&M costs (2023$/year) = 18.1 × flow (GPD) + 144,207

Capital and O&M costs assuming on-site solids management for flows between 150 and 1,000 GPM:

membrane filtration followed by spray evaporation with on-site solids management – capital costs (2023$) = 77.2 × flow (GPD) + 18,411,536

membrane filtration followed by spray evaporation with on-site solids management – O&M costs (2023$/year) = 10.2 × flow (GPD) + 843,692

Capital and O&M costs assuming off-site solids management for flows between 150 and 1,000 GPM:

membrane filtration followed by spray evaporation with off-site solids management – capital costs (2023$) = 69.4 × flow (GPD) + 18,462,172

membrane filtration followed by spray evaporation with off-site solids management – O&M costs (2023$/year) = 19.5 × flow (GPD) + 844,091

The EPA estimated plant-level SDE costs as follows:

- For plants opting in to the 2020 rule VIP, the EPA estimated zero capital and zero O&M costs.
- For all other plants with FGD wastewater discharges, the EPA estimated plant-specific capital and O&M costs.
  - The EPA estimated capital costs for SDE using the FGD purge flow rate. Where a plant-level purge flow was greater than 1,000 GPM, the EPA estimated costs for a separate SDE system at each EGU at the plant, using the unit-level purge flow rate along with the corresponding cost equation, and then summed the unit-level costs to the plant level.
  - The EPA estimated O&M costs as the difference between LRTR O&M costs and SDE O&M costs, using the FGD optimized flow rate. All plants are assumed to be currently operating LRTR systems that they will replace with SDE systems for this technology option. To estimate this difference, the EPA estimated LRTR O&M costs using the equations in Section 5.1.2 and estimated SDE O&M costs using the equations discussed in this section. O&M costs for the SDE technology option were calculated as the difference between LRTR and SDE values. Where the plant-level purge flow was greater than 1,000 GPM, the EPA also estimated costs for separate SDE systems at each EGU at the plant, using the unit-level optimized flow rate along with the corresponding cost equation, and then summed the unit-level costs to the plant level.

5.1.5 Cost Methodology for Thermal Evaporation

As described in the *Flue Gas Desulfurization and Combustion Residual Leachate Thermal Evaporation Cost Methodology* memorandum, the EPA estimated plant-level thermal evaporation costs using average costs from two technology vendors (U.S. EPA, 2024l).

The resulting cost equations are as follows:

$$\text{thermal evaporation capital cost (2023\$)} = (\text{Vendor 1 capital cost} + \text{Vendor 2 capital cost}) \div 2$$

$$\text{thermal evaporation O\&M cost (2023\$/year)} = (\text{Vendor 1 O\&M cost} + \text{Vendor 2 O\&M cost}) \div 2$$

The EPA estimated plant-level thermal evaporation costs as follows:

- For plants opting in to the 2020 rule VIP, the EPA estimated zero capital and zero O&M costs.
- For all other plants with FGD wastewater discharges, the EPA estimated plant-specific capital and O&M costs.
  - The EPA estimated capital costs for thermal evaporation using the FGD purge flow rate.
  - The EPA estimated O&M costs as the difference between LRTR O&M costs and thermal evaporation O&M costs, using the FGD optimized flow rate. All plants are assumed to be currently operating LRTR systems that they will replace with thermal evaporation systems for this technology option. To estimate this difference, the EPA estimated LRTR O&M costs using the equations in Section 5.1.2 and estimated thermal evaporation O&M costs using the equations discussed in this section. O&M costs for the thermal evaporation technology option were calculated as the difference between LRTR and thermal evaporation values.

5.1.6 Cost Methodology for Zero Discharge

To estimate zero-discharge costs for FGD wastewater, the EPA compared the costs for membrane filtration (see Section 5.1.3) and SDE (see Section 5.1.4) for each plant and selected the least cost technology. Refer to the Least-Cost Technology by Plant (U.S. EPA, 2024m). The EPA did not consider thermal evaporation costs in its least cost option assessment because some of the costs are being treated as CBI, pursuant to claims made by technology vendors.

5.2 BA Transport Water

The EPA estimated BA transport water costs for wastewater treatment and pollutant prevention technologies that are equivalent to the technology bases defined by the final regulatory options. The BA transport water technology options considered as part of the rule include high recycle rate (HRR) and zero discharge. For the HRR option, the EPA estimated costs for mechanical drag system (MDS) installations and remote MDS installations with a purge. For the zero-discharge option, the EPA estimated costs for MDS installations and closed-loop remote MDS installations. (A closed-loop remote MDS installation includes an RO system to allow complete recycle, along with return pumps, pipes, and surge tank capacity.)

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

For remote MDS installations, the EPA included costs to install and operate the following, consistent with the 2020 rule methodology:

- Remote MDS (away from the boiler).
- Sump.
- Recycle pumps.
- Chemical feed system.[28]
- Semi-dry silo.

For both technology options considered, the EPA also included the capital and O&M costs of transporting all BA and disposing of it in a landfill.

Section 5.2.1 describes the cost inputs for the 2024 final rule. Sections 5.2.2 and 5.2.3 present the EPA's methodology for estimating costs for HRR and zero discharge, respectively.

5.2.1 BA Transport Water Cost Calculation Inputs

To estimate plant-level baseline and post-compliance costs of implementing BA transport water technologies, the EPA developed a cost calculation database. This database combines plant-specific input values (including details on BA production, current BA handling systems, and the use of on-site and off-site landfills) with the relationships between costs and EGU capacity or BA generation described in Sections 5.2.2 and 5.2.3 to estimate baseline and post-compliance costs for each plant (ERG, 2024b). For the 2024 final rule, the EPA used input data compiled from the 2015 and 2020 rules—including Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data—and updated these data based on new information gathered from industry and information available from the Department of Energy and National Pollutant Discharge Elimination System permits (see Section 2). This section describes the updates to cost inputs from the 2020 rule.

Population

The EPA identified coal-fired power plants that operate wet BA handling systems and discharge BA transport water to surface water or a POTW, and that are not expected to retire or convert fuel sources

[28] The EPA included costs for a chemical feed system to control pH of the recirculating system to prevent scaling within the system. Information in the record indicates that few, if any, plants are likely to need chemical feed systems. However, because the EPA could not conclusively determine that none would, or which plants would be more likely to need chemical feed systems, the EPA estimated this cost 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 remote MDS.

by December 31, 2028. The EPA started with the population of EGUs from the 2020 rule and updated that population based on industry-provided data and new publicly available data on operational changes.

Production Data

For each applicable EGU, the EPA estimated the amount of wet BA produced in tons per year (TPY), the generating capacity in megawatts (MW), and the net generation in megawatt-hours (MWh). The EPA used BA production and capacity values reported in the Steam Electric Survey as input values for estimating compliance costs for the 2024 final rule.

Cost Type Flags

The EPA used data from the Steam Electric Survey, site visits, public comments, and other industry sources, discussed in Section 2, to identify the types of BA handling systems currently operating at each plant. For each type of BA handling system, the EPA determined the equipment or services needed to implement each technology option. The EPA categorized each EGU into the following cost categories:

- Steam electric EGUs equipped with only wet BA handling systems that discharge BA transport water.
- Steam electric EGUs equipped with only wet BA handling systems that discharge BA transport water and have space constraints preventing the installation of MDSs.
- Steam electric EGUs already operating remote MDSs.
- Steam electric EGUs equipped with only wet BA handling systems that recycle all their BA sluice but that can discharge BA transport water from emergency outfalls. The EPA defined these as BA management plants.
- Steam electric EGUs operating dry BA handling systems.

Flow Rate

The 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 for each technology option evaluated for the 2024 final rule.

The EPA defined the baseline as plants complying with the 2020 rule. For baseline conditions, the EPA estimated BA transport water flow rates for the HRR technology option, which would allow plants to discharge a portion of their BA transport water. The EPA estimated BA transport water flow rates for three compliance approaches available to most plants:

- *Zero flow.* For a plant using a dry BA handling system to comply with baseline or a technology option (*e.g.,* under-boiler mechanical drag system), the discharge flow rate equals zero.
- *Purge flow*. For each plant using a recirculating BA handling system to comply with baseline or a technology option (*e.g.,* remote MDS operated with a purge instead of a completely closed loop), the EPA estimated a BA transport water purge flow rate. The EPA calculated BA transport water purge flow rates for remote MDS installations based on the relationship between the plant's generating capacity and the volume of the total wetted, active components of the remote MDS, consistent with the methodology described in Section 5.2.3. Where the EPA identified EGUs that were designated for retirement or fuel conversion, the EPA adjusted the plant generating capacity to account for changes.
- *Sluice flow*. For plants using a surface impoundment plus best management practice (BMP) plan to comply with baseline (per the 2020 rule), the EPA identified one plant in the low utilization subcategory for which the discharge flow rate equals the plant's BA sluice flow.

Baseline Treatment Technology

For this cost analysis, the EPA assumed that plants subject to the BA transport water discharge requirements in the 2020 rule would install the treatment technology basis defined for the 2020 rule and any applicable subcategories (*i.e.,* baseline). For baseline and regulatory options costs, the EPA accounted for updates to the industry profile, including retirements and NOPPs. Table 9 outlines the baseline scenarios for the plants included in the EPA's final rule analyses and the corresponding estimated compliance costs. Baseline assumptions for BA transport water account for the CCR Part A rule (40 CFR 257).

Table 9. 2024 Rule BA Transport Water Technology Bases

2024 Technology Option Evaluated	2020 Rule Subcategory	2024 Baseline Treatment Technology	Estimated Incremental Capital Compliance Cost	Estimated Incremental O&M Compliance Cost
HRR	All other BA discharges	Dry handling or HRR system	Costs are equal to zero	Costs are equal to zero
	Low utilization boilers: all EGUs have 24-month average utilization < 10%	Surface impoundment + BMP plan	Costs for MDS/remote MDS with purge	Costs for MDS/remote MDS with purge
Zero discharge	All other BA discharges	Dry handling or HRR system	Costs for RO	Costs for RO
	Low utilization boilers: all EGUs have 24-month average utilization < 10%	Surface impoundment + BMP plan	Costs for MDS/remote MDS with purge	Costs for MDS/remote MDS with purge

5.2.2 Cost Methodology for HRR

As described in the RIA, the EPA's baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from changes to the existing 2020 limitations and standards. Therefore, the EPA assumed that plants will have installed MDS or remote MDS in compliance with the 2020 rule and will incur zero costs to comply with HRR technology options, except for the one plant in the 2020 rule low utilization subcategory. For the remaining low utilization plant, the EPA compared the costs of installing an MDS and a remote MDS and chose the least cost option as the technology basis for HRR. The EPA calculated plant-specific MDS and remote MDS compliance costs for the 2024 rule EGU-level BA generation and/or EGU capacity using the on-site cost equations (based on the characteristics of the low utilization plant). The EPA updated the 2020 rule cost curves by escalating them to 2023 dollars as described in Section 5.1.2. The recurring expenses for MDS and remote MDS installations account for the cost of chain replacement, which may be needed every three years for MDS installations and every five years for remote MDS installations. To estimate plant-level costs, the EPA first calculated the capital and O&M costs at the EGU-level, using the following curves:

$$\text{EGU MDS capital cost (2023\$)} = (52{,}567 \times [\text{MW}]) + 7{,}291{,}365$$

$$\text{MDS annual O\&M cost (2023\$/year)} = (25.186 \times [\text{TPY}]) + 770{,}542$$

$$\text{MDS three-year recurring O\&M cost (2023\$)} = \$302{,}076$$

$$\text{EGU remote MDS capital cost (2023\$)} = [(38{,}518 \times [\text{MW}]) + 5{,}063{,}145] + \text{building cost}$$

$$\text{remote MDS annual O\&M cost (2023\$/year)} = (25.937 \times [\text{TPY}]) + 1{,}144{,}271$$

remote MDS five-year recurring O&M cost (2023$) = $302,076

The EPA added surface impoundment cost savings to the MDS and remote MDS capital and O&M EGU-level costs. Consistent with the 2020 rule methodology, the EPA used Steam Electric Survey data to identify plants with at least one impoundment that contains BA transport water and that has not been designated for retirement. Where the EPA had data indicating plants had installed dry or HRR BA handling systems since the 2020 rule, the EPA assumed these plants would opt to no longer operate impoundments for BA handling, resulting in surface impoundment cost savings. The EPA also assumed that plants whose impoundments are expected to close due to CCR Part A rule requirements would no longer use impoundments for BA handling, resulting in surface impoundment cost savings. The EPA estimated plant-level cost savings for no-longer-operating impoundments based on the total amount of BA solids currently handled wet at the plant. The EPA updated the 2020 rule BA impoundment O&M cost savings by escalating them to 2023 dollars as described in Section 5.1.2.

total BA impoundment O&M cost savings (2023$/year) =
BA impoundment operating cost savings + BA earthmoving cost savings

Where:

BA impoundment operating cost savings	=	Total impoundment operating cost savings.
BA earthmoving cost savings	=	O&M cost associated with the earthmoving equipment savings.

The EPA estimated the BA impoundment operating cost savings by first calculating the plant MW factor and the plant-specific unitized cost.

$$\text{plant MW factor} = 7.569 \times (\text{plant size})^{-0.32}$$

Where:

plant size	=	Plant size in MW (the plant nameplate capacity for only those EGUs in the BA costed population).

plant-specific unitized cost = impoundment operating unitized cost × plant MW factor

Where:

plant-specific unitized cost	=	Plant-specific cost to operate a front-end loader (in 2023$/ton).
impoundment operating unitized cost	=	2010 unitized annual cost to operate a combustion residual impoundment. The EPA used a unitized cost value of $10.78 per ton (in 2023$).
plant MW factor	=	Factor to adjust combustion residual handling costs based on plant capacity.

Next, the EPA calculated the BA impoundment operating cost savings by multiplying the plant-specific unitized cost by the amount of BA produced by the plant, in TPY.

BA impoundment operating cost savings (2023$/year) =
plant-specific unitized cost × plant BA tonnage

Where:

plant-specific unitized cost	=	Plant-specific cost to operate a front-end loader (in 2023$/ton).
plant BA tonnage	=	Total BA tonnage, dry basis, for each plant (in TPY). The EPA calculated this value by multiplying the wet BA generation rate (in TPD) by operating days (days per year) for each EGU, then summing the EGU-level values to the plant level.

To calculate BA earthmoving cost savings, the EPA first calculated the plant-specific front-end loader unitized cost by multiplying the plant MW factor by the front-end loader unitized cost.

plant-specific front-end loader unitized cost (2023$/ton) =
front-end loader 2010 unitized O&M cost × plant MW factor

Where:

front-end loader 2010 unitized O&M cost	=	2010 unitized cost value that represents the O&M of the front-end loader used to redistribute ash at an impoundment. The EPA calculated this value to be $3.65 per ton (in 2023$).
plant MW factor	=	Factor to adjust combustion residual handling costs based on plant capacity.

Next, the EPA calculated the BA earthmoving cost savings by multiplying the plant-specific unitized cost by the amount of BA produced by the plant in TPY.

BA impoundment earthmoving cost savings (2023$) =
plant-specific front-end loader unitized cost × plant BA tonnage

Where:

plant-specific front-end loader unitized cost	=	Plant-specific cost value that represents the O&M of the front-end loader used to redistribute ash at an impoundment.
plant BA tonnage	=	Total BA tonnage, dry basis, for each plant (in TPY). The EPA calculated this value by multiplying the wet BA generation rate (in TPD) by operating days (days per year) for each EGU, then summing the EGU-level values to the plant level.

The EPA calculated 10-year recurring costs associated with operating the earthmoving equipment (*i.e.,* front-end loader) using the estimated cost and average expected life of a front-end loader. The EPA determined the cost of the earthmoving equipment to be $695,760 (2023$) and assumed an expected life of 10 years.

The EPA then summed the MDS and remote MDS EGU-level costs to the plant level. The EPA also added a plant-level capital cost of $1,534,191 (2023$) to build a roof over the remote MDS to mitigate stormwater contributions to the system. This additional roof cost was applied at the plant level because a plant would likely use one roof to cover the entire fleet of remote MDS installations. O&M costs for the roof were assumed to be zero, as the structure is only intended to protect from stormwater and does not have heating, ventilation, or air conditioning (HVAC).

The EPA estimated HRR plant-level costs using the following assumptions:

- The EPA identified one plant, Merrimack Station (Plant ID 3095), that submitted a NOPP for the low utilization subcategory.[29] For this plant, estimated capital costs are equal to MDS or remote MDS with purge. The EPA estimated HRR O&M costs using equations in Section 5.2.2.
- For all other plants with BA discharges, the EPA estimated zero capital and zero O&M costs.

5.2.3 Cost Methodology for Zero Discharge

The EPA estimated costs to treat a BA transport water purge stream using a high-pressure RO system to remove dissolved solids and comply with a zero-discharge standard. The EPA assumed a daily purge rate equal to 2 percent of the total estimated BA transport system volume (*i.e.,* the plant-level volume associated with the BA hoppers, remote MDS, sluice pipes, and surge tanks), excluding redundant spare systems, maintenance tanks, and similar infrequently used equipment. Permeate from the RO system would be recycled back into the remote MDS while the RO reject, or brine, would be transported to a centralized waste treatment facility for disposal. The EPA also assumed that managing the remote MDS as a zero-discharge system may require additional surge tank capacity to hold BA hopper water during maintenance activities. These additional costs associated with zero-discharge operation were calculated at the plant level because one RO system can treat the remote MDS slipstream from all remote MDSs operating at a plant.

For plants identified as likely to install remote MDSs to comply with the 2020 rule or the CCR Part A rule requirements, the EPA added capital costs for RO, surge tank, piping, and pumps to the plant-level total remote MDS capital cost described in Section 5.2.2. To estimate the total cost for a zero-discharge remote MDS, the EPA added O&M costs for the additional equipment, as well as the costs of transporting and disposing of the RO brine, to the remote MDS O&M cost described in Section 5.2.2. For plants identified as having installed remote MDSs to comply with the 2020 rule, the EPA assumed that the additional capital and annual O&M costs associated with treating a remote MDS slipstream with RO would be the only incremental costs incurred to operate the system as zero discharge.

To estimate the RO capital and O&M costs, the EPA used cost curves from the 2020 rule and escalated them to 2023 dollars as described in Section 5.1.2.

The EPA first estimated the total remote MDS volume based on information provided by equipment vendors knowledgeable about boiler configurations (including ash hopper volumes) and remote MDS configurations and sizes. For plants with plant-level capacities less than or equal to 200 MW, the EPA assumed that the total remote MDS volume is 175,000 gallons, based on data provided by vendors and best professional judgement (ERG, 2019b). For plants with plant-level capacities greater than 200 MW, the EPA used the following equation, developed from industry-level data on remote MDS installations, to estimate the total system volume (ERG, 2019b).

$$\text{total remote MDS volume (gallons)} = (347.29 \times \text{plant-level capacity}) + 146{,}398$$

Where:

plant-level capacity	=	Sum of EGU capacities (MW) flagged for BA compliance costs.

Based on the estimated total remote MDS volume, the EPA calculated the slipstream flow rate in GPM as follows:

[29] After the EPA completed final rule analyses, Granite Shore Power announced that Merrimack Station would voluntarily retire (refer to preamble Section VII.C.2).

$$\text{slipstream flow (GPM)} = (\text{total remote MDS volume} \times 0.02/\text{day}) \div 1{,}440 \text{ minutes/day}$$

Where:

total remote MDS volume	=	Total volume (in gallons) of all remote MDSs expected to be operating at the plant.

The EPA developed a relationship between total RO capital cost and purge flow, based on data collected from wastewater treatment vendors and best professional judgement (ERG, 2019b). The RO capital cost curve (equation shown below) was used to estimate EGU-level capital costs for RO treatment of the remote MDS slipstream.

$$\text{RO capital cost (2023\$)} = (86{,}361 \times \text{slipstream flow}) + 3{,}373{,}926$$

The EPA also developed a relationship between annual O&M cost and purge flow, based on data collected from wastewater treatment vendors (ERG, 2019b). The RO O&M cost curve (equation shown below) was used to estimate plant-level annual O&M costs for RO treatment of a BA transport water slipstream from the remote MDS.

$$\text{RO O\&M cost (2023\$/year)} = \$0.01468 \times \text{slipstream flow} \times 60 \text{ minutes/hour} \times 24 \text{ hours/day} \times 365 \text{ days/year}$$

The EPA calculated capital costs for the surge tank. The EPA assumed that only one EGU will need to empty the BA hopper at any one time; therefore, the EPA developed a relationship between surge tank size and the capacity of the largest EGU at the plant (defined by capacity in MW), based on information provided by the industry and vendors (ERG, 2019b).

Once the EGU with the largest nameplate capacity (MW) was identified, the EPA calculated the size of the surge tank in gallons. The EPA accounted for an additional 50 percent capacity for the surge tank by multiplying the relationship by a tank sizing factor (1.5).

$$\text{tank size (gallons)} = 63 \times \text{EGU capacity} \times \text{tank sizing factor}$$

Where:

EGU capacity	=	Capacity of the EGU (MW).
tank sizing factor	=	1.5.

The EPA then estimated the cost as a function of tank size based on information provided by vendors during the development of the 2015 rule. For tanks smaller than 50,000 gallons:

$$\text{tank capital cost (2023\$)} = [(3.170 \times \text{tank size}) + 33.32 \times (\text{tank size} \times 1.65)^{0.548}]$$

Where:

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

For tanks larger than 50,000 gallons:

$$\text{tank capital cost (2023\$)} = [(5.058 \times \text{tank size}) + 33.316 \times (\text{tank size} \times 1.65)^{0.548}]$$

Where:

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

The EPA estimated the purchased equipment capital costs for the piping and pumps using the methodology for the FGD wastewater recycle piping and wastewater forwarding pumps (used to return wastewater back to the scrubber). The EPA then calculated the pump capital cost as a function of the flow rate from the surge tank using cost information provided by vendors during the development of the 2015 rule.

$$\text{pump capital cost (2023\$)} = [3{,}227 \times \ln(1.61 \times \text{flow}) - 3{,}389.8] \times 6.101$$

Where:

flow	=	Daily flow rate from the surge tank (in GPM, assuming discharge over five hours).

The EPA estimated the capital cost of 2,640 feet of piping using an assumed distance of 0.25 miles between the surge tank and the BA hopper, based on the EPA's best professional judgement, information from BA handling vendors about remote MDS placement at a plant, and costs data provided by pipe vendors for the 2015 rule. The EPA's estimate of the capital cost for 2,640 feet of piping is $54,858 (2023$).

The EPA estimated the direct capital costs by multiplying the sum of the purchased equipment costs for the tank, pumps, and piping (*i.e.,* the total purchased equipment cost) by 2. The EPA used this relationship to account for the costs of delivery of purchased equipment, installation of purchased equipment, instrumentation and controls, piping and electrical, service facilities, building services, and land (if purchase is required).

$$\text{direct capital costs} = 2 \times \text{total purchased equipment cost}$$

The EPA then estimated the indirect capital costs by multiplying the sum of the total purchased equipment and direct capital costs by 0.43. The EPA used this relationship to account for engineering and supervision, construction expenses, contractor's fees, and contingency.

$$\text{indirect capital costs} = 0.43 \times (\text{total purchased equipment cost} + \text{direct capital costs})$$

Finally, the EPA estimated total capital costs by summing the total purchased equipment, direct, and indirect capital costs.

$$\text{total capital costs} = \text{total purchased equipment cost} + \text{direct capital costs} + \text{indirect capital costs}$$

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

$$\text{total tank/pump/piping O\&M costs} = \text{energy cost} + \text{maintenance cost}$$

To calculate the energy cost, the EPA estimated the annual energy requirement in kilowatt-hours (kWh) to operate the pumps, based on the 2015 rule cost methodology.

$$\text{annual energy requirement (kWh/year)} = (0.02219 \times \text{flow} + 2.019) \times 17.89$$

Where:

flow	=	Daily flow rate from the surge tank (in GPM, assuming discharge over five hours).

The EPA 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. DOE Energy Information Administration (U.S. DOE, 2011), in 2023 dollars.

$$\text{energy cost (2023\$)} = \text{national energy cost} \times \text{annual energy requirement}$$

Where:

national energy cost	=	($0.0485/kWh × 1.468) (in 2023$).
annual energy requirement	=	Annual energy requirement to operate pumps (in kWh/year).

To estimate the total maintenance costs for the 2015 rule, the EPA developed a relationship between BA slipstream flow and the cost to maintain the surge tank, pumps, and piping.

$$\text{maintenance cost (2023\$)} = 611.466 \times \text{flow}$$

Where:

flow	=	Daily flow rate from the surge tank (in GPM, assuming discharge over five hours).

To estimate costs for transportation and disposal of the RO brine, the EPA calculated O&M costs associated with hauling the brine off site to a centralized waste treatment (CWT) facility and the costs incurred for using CWT.

The EPA calculated brine flow rate based on the average recovery from the membrane treatment vendors used for FGD wastewater.

$$\text{brine flow} = 0.30 \times \text{purge flow}$$

The EPA estimated the weight of the brine based on the weight of the solids in the brine and the weight of the water. The EPA estimated the solids in the brine based on the average total dissolved solids (TDS) concentration in BA transport water for the entire purge flow (this assumes that all solids from the BA purge will be retained in the brine, which is likely an overestimate).

$$\text{annual brine solids (TPY)} = \text{BA purge (GPD)} \times \text{average TDS concentration} \times 3.78\ \text{L/gal} \times 0.001\ \text{g/mg} \times (1.102 \times 10^{-6}\ \text{tons/g}) \times 365\ \text{days per year}$$

Where:

BA purge	=	2 percent of the total BA system volume in GPD.
average TDS concentration	=	Average TDS concentration in BA transport water (see Table 6-2 of the 2020 Supplemental TDD), 1,290 mg/L.
annual brine water weight (TPY)	=	brine flow (GPD) × 0.00417 tons/gal × 365 days per year.

The EPA calculated the total weight of brine to be disposed of annually as the sum of the brine solids and the water weight.

annual brine weight (TPY) = annual brine solids + annual brine water weight

The 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 location 25 miles from the plant.

transportation cost (2023$) = annual brine weight × $13.514 per ton

The EPA estimated disposal costs using data compiled as part of the rulemaking that established pretreatment standards for 40 CFR Part 435 (Oil and Gas Extraction), Subpart C (*i.e.,* onshore unconventional oil and gas). Wastewater management using a CWT for TDS removal ranged from $3 to $11 per barrel (U.S. EPA, 2016). Using the average value of $7 per barrel, the EPA estimated that the disposal cost at a CWT would be $0.167/gallon (2005$), which escalated to $0.245/gallon in 2023$. Annual disposal costs were estimated using the following equation:

disposal cost (2023$) = brine flow (GPD) × $0.245/gallon

To estimate the annual cost for brine transportation and disposal, the EPA summed the transportation and disposal costs.

brine transport and disposal annual cost = transportation cost + disposal cost

The EPA estimated zero-discharge plant-level costs according to the following assumptions:

- For plants opting in to the low utilization subcategory, the EPA estimated costs equal to an MDS or a remote MDS with a purge. For a plant to achieve zero discharge, the steps outlined in this section must be added to the plant's overall cost calculation from Section 5.2.2.
- For all other plants with BA discharges, the EPA estimated costs equal to the addition of an RO system only.

5.3 Combustion Residual Leachate

For the 2024 final rule, the EPA estimated costs for plants to install and operate four technologies for CRL: CP, membrane filtration, SDE, and thermal evaporation.

For CP treatment of CRL, the EPA included the following treatment components:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems for lime, organosulfide, ferric chloride, and polymers.
- Mercury analyzer.
- Compliance monitoring (including sample collection and analysis).
- Solids handling (sludge holding tank and filter press).
- Transportation and disposal of solids in a landfill.

For membrane filtration treatment of CRL, the EPA included the following components, consistent with the methodology used for FGD wastewater:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).

- CP chemical feed systems for lime, organosulfide, ferric chloride, and polymers.
- Membrane filtration treatment equipment (membrane filtration, RO, and storage tanks).
- Additional FA purchase (if plant was identified as having an FA deficit).[30]
- Brine encapsulation.
- Transportation and disposal of solids in a landfill.

For SDE treatment of CRL, the EPA included the following treatment components, consistent with the methodology used for FGD wastewater:

- Pretreatment using membrane filtration (for flows greater than 150 GPM only) (includes membrane filtration, RO, and storage tanks).
- SDE equipment.
- Transportation and disposal of solids in a landfill.

For thermal evaporation treatment of CRL, the EPA included the following treatment components:

- Brine concentration and encapsulation or crystallization equipment.
- Transportation and disposal of solids in a landfill.

Section 5.3.1 describes the process for developing the CRL cost calculation inputs. Sections 5.3.2, 5.3.3, 5.3.4, and 5.3.5 present the EPA's methodology for estimating costs for CP, membrane filtration, SDE, and thermal evaporation, respectively. Section 5.3.6 presents the EPA's methodology for determining the least cost zero-discharge technology option for CRL.

As described in Section 3.2.3, the EPA notes that unlined landfills and unlined surface impoundments not expected to clean close may potentially discharge unmanaged CRL. Such discharges may be covered under the ELGs when they are determined on a case-by-case basis to be the functional equivalent of a direct discharge. To evaluate the potential costs and loadings of such discharges, the EPA conducted a bounding analysis, which is documented in the memorandum *Evaluation of Unmanaged CRL* (U.S. EPA, 2024). The EPA summarizes the costs for unmanaged CRL in Section 5.5.

5.3.1 CRL Cost Calculation Inputs

To estimate plant-level baseline and post-compliance costs of implementing CRL treatment technologies, the EPA developed cost calculation databases. These databases combine plant-specific input values, including CRL flow and existing treatment, with the relationships between costs and CRL flow rates described in Section 5.3.2 to estimate baseline and post-compliance costs for each plant (ERG, 2023, 2023a, 2023b, 2024). For the 2024 final rule, the EPA started with input data from the 2015 rule, including Steam Electric Survey data, and then updated the data with other publicly available data described in Section 2. This section describes the cost inputs.

Population

The EPA used data from the Steam Electric Survey (U.S. EPA, 2015) and the Office of Resource Conservation and Recovery's (ORCR's) Comprehensive Compliance Report (U.S. EPA, 2023b) to identify the population of landfills and surface impoundments that contain combustion residuals and that collect CRL and discharge it to surface waters or POTWs. The EPA updated this population to reflect recent changes to the profile of steam electric power plants and removed plants where all EGUs were retired by December 31, 2023, as described in *Identification of Combustion Residual Leachate (CRL) Discharges from*

[30] Refer to the *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* for more information (U.S. EPA, 2024h).

Leachate Collection Systems and Overview of Compliance Costs and Pollutant Loadings Analyses (U.S. EPA, 2024d).[31]

For each new landfill and surface impoundment, the EPA used data from the Steam Electric Survey and other publicly available information to identify the most appropriate discharge location and receiving water. Where a plant reported all discharges to a single receiving water (*i.e.,* all outfalls discharge to the same waterbody), the EPA used this receiving water. Where a plant reported discharges to multiple waterbodies, the EPA evaluated outfall data and water balance diagrams to identify the most appropriate receiving water(s) for CRL. See the *Receiving Waters Characteristics Analysis and Supporting Documentation for the Environmental Assessment of the Final Supplemental Steam Electric Rule* memorandum for further details (U.S. EPA, 2024n,).

Flow Rate

The EPA used the methodology described in Section 9.4.1 of the 2015 TDD to estimate CRL flow rates. Where information on CRL flow rate was available in the Steam Electric Survey, the EPA used this value.

For landfills, where landfill size (acreage) information was available in the Steam Electric Survey, the EPA estimated that plants collect CRL from 75 percent of the total acreage for active landfills, 5 percent of the total acreage for inactive landfills, and 17 percent of the total acreage for retired landfills. The EPA also used survey data to estimate the median CRL discharge rate in GPD per acre of landfill: 887 for active and inactive landfills, and 113 for retired landfills. The EPA subsequently estimated the unknown CRL flow rates using this information and the landfill size.

For active landfills:

$$\text{CRL flow (GPD)} = 887\ \text{GPD/acre} \times 0.75 \times \text{landfill acreage}$$

For inactive landfills:

$$\text{CRL flow (GPD)} = 887\ \text{GPD/acre} \times 0.05 \times \text{landfill acreage}$$

For retired landfills[32]:

$$\text{CRL flow (GPD)} = 113\ \text{GPD/acre} \times 0.17 \times \text{landfill acreage}$$

Where no CRL flow or landfill size information was available, the EPA used the median CRL flow rate from the Steam Electric Survey: 46,160 GPD for active landfills and 29,651 GPD for inactive landfills.

For surface impoundments where information on CRL flow rate was not available, the EPA used the median CRL flow rate from the Steam Electric Survey: 34,560 GPD.

The EPA also considered the flow rate for active and inactive landfills following closure. The EPA estimates that, post closure, landfills and surface impoundments will continue to generate CRL at 10 percent of their active or inactive flow rate.

The EPA used the following equation to calculate the CRL post-closure flow:

$$\text{post-closure CRL flow} = \text{CRL flow (GPD)} \times 0.10$$

[31] If a plant in the CRL population converted to a different fossil fuel source (*e.g.,* gas-fired), the 2024 final rule still applies, and the plant remains in the CRL population.

[32] The EPA included retired landfills in the analysis if they are located at active plants with open (active/inactive) landfills as plants often combine CRL from all onsite landfills for treatment and discharge.

The EPA estimated technology option costs using both the CRL flow and the post-closure CRL flow. The EPA summed all landfill and surface impoundment flow rates at a particular plant and used this total flow rate to estimate technology option costs at the plant level.

Treatment-in-Place Data

In 2015, the EPA identified one plant that was operating a biological treatment system to treat landfill CRL (combined with FGD wastewater) and one plant that was building a biological treatment system to treat landfill CRL. In 2020, the EPA identified one plant that was operating a thermal treatment system to treat landfill CRL (combined with FGD wastewater) (ERG, 2020a). Through public comments, the EPA further identified two plants with CP treatment in place for landfill CRL (ERG, 2023). The EPA did not identify any plants with treatment in place for surface impoundment CRL.

Landfill Data

The EPA determined whether each plant in the population of landfills described in Section 0 will incur on-site or off-site transportation and disposal costs. Plants identified as having an active or inactive landfill incurred compliance costs for on-site transportation and disposal of treatment residuals; all other plants incurred compliance costs for off-site transportation and disposal. For post-closure cost estimates (for active and inactive landfills following closure), the EPA assumed off-site transportation and disposal.

5.3.2 Cost Methodology for CP

To estimate CP costs for CRL, the EPA used cost data from the 2015 and 2020 rules for CP as stand-alone treatment for FGD wastewater. Starting with the capital and O&M cost curves presented in Section 5.2.2 of the 2020 Supplemental TDD, the EPA sized the treatment system for CRL flows (rather than FGD flows). The EPA updated the 2020 rule cost curves by escalating them to 2023 dollars as described in Section 5.1.2.

The EPA used the following cost curves to estimate CP capital and O&M costs:

$$\text{CP capital costs with on-site transport/disposal (2023\$)} = 51.31 \times \text{CRL flow} + 10{,}334{,}835$$

$$\text{CP O\&M costs with on-site transport/disposal (2023\$/year)} = 5.939 \times \text{CRL flow} + 337{,}016$$

$$\text{CP capital costs with off-site transport/disposal (2023\$)} = 50.40 \times \text{CRL flow} + 10{,}906{,}369$$

$$\text{CP O\&M costs with off-site transport/disposal (2023\$/year)} = 8.116 \times \text{CRL flow} + 321{,}529$$

The CP system includes an in-line mercury analyzer. This process control mechanism has an expected life of six years. To estimate the recurring cost of replacing the mercury analyzer every six years, the EPA used costs originally obtained for the 2015 rule and escalated them to 2023 dollars. The recurring cost was estimated as $147,211 (2023$).

For plants identified as having existing treatment in place for CRL, the EPA estimated no additional capital costs or recurring costs but estimated O&M costs equal to $108,029 (2023$/year) to account for compliance monitoring of the treated effluent. Compliance monitoring includes sampling labor and materials as well as the costs associated with sample preservation, shipping, and analysis for the pollutants selected for regulation (arsenic and mercury).

5.3.3 Cost Methodology for Membrane Filtration

To estimate membrane filtration technology option costs for CRL, the EPA first estimated CP pretreatment costs. The EPA used cost data from the 2015 and 2020 rules for CP pretreatment of FGD wastewater, specifically the cost equations from Section 5.2.3 of the 2020 rule TDD (U.S. EPA, 2020). The EPA updated the cost equations to 2023 dollars as described in Section 5.1.2 of this TDD.

The EPA used the following cost curves to estimate CP pretreatment capital and O&M costs:

CP pretreatment capital costs with on-site transport/disposal (2023$) = 53.08 × CRL flow + 10,140,518

CP pretreatment O&M costs with on-site transport/disposal (2023$/year) = 6.035 × CRL flow + 223,603

CP pretreatment capital costs with off-site transport/disposal (2023$) = 52.79 × CRL flow + 10,727,925

CP pretreatment O&M costs with off-site transport/disposal (2023$/year) = 8.200 × CRL flow + 213,413

The EPA used the methodology described for FGD wastewater in Section 5.1.3 for estimating the membrane filtration costs.

The EPA estimated plant-level CRL capital, O&M, and one-time costs using the CRL flow rate in GPD as described in Section 0. The EPA estimated the total membrane filtration technology option costs as the sum of the CP pretreatment and membrane filtration costs. For plants identified as having existing treatment in place for CRL, the EPA estimated no CP pretreatment capital or O&M costs, except compliance monitoring of the treated effluent. The EPA did not incorporate LRTR O&M cost savings, as these are unique to FGD wastewater.

5.3.4 Cost Methodology for SDE

To estimate SDE costs for CRL, the EPA used the methodology described for FGD wastewater in Section 5.1.4. In place of the wastewater flow rate (FGD flow), the EPA used the CRL flow rate in GPD as described in Section 0. The EPA did not account for LRTR O&M cost savings, which are only applicable for FGD wastewater.

5.3.5 Cost Methodology for Thermal Evaporation

To estimate thermal evaporation costs for CRL, the EPA followed the same methodology described for FGD wastewater in Section 5.1.5, substituting the CRL flow rate for the FGD wastewater flow rate. The EPA did not incorporate LRTR O&M cost savings, which are only applicable for FGD wastewater.

5.3.6 Cost Methodology for Zero Discharge

To estimate zero-discharge costs for CRL, the EPA compared the costs for membrane filtration (see Section 5.3.3) and SDE (see Section 5.3.4) for each plant and selected the least cost technology. Refer to the Least-Cost Technology by Plant (U.S. EPA, 2024m). The EPA did not consider thermal evaporation costs in its least cost option assessment because some of the costs are being treated as CBI, pursuant to claims made by technology vendors.

However, where the EPA has information on plants expecting to retire under the 2024 final rule, the EPA considered the least cost option after taking into account reductions in CRL flow rates expected following the closure of a landfill or surface impoundment, as described in Section 0. Specifically, the EPA considered two treatment options for zero discharge for plants retiring after 2034:

- Installing a membrane filtration treatment system (see Section 5.3.3), designed for the CRL flow rate; or
- Installing an SDE treatment system (see Section 5.3.4), designed for the CRL flow rate, then installing a membrane filtration system (see Section 5.3.3), designed for the post-closure flow rate.

For plants that are retiring by 2034, the EPA compared the cost of installing an SDE with the cost of installing membrane filtration, both designed for the CRL flow rate. The EPA estimated the total cost for each of these treatment options and chose the least cost option, as described in the Least-Cost Technology by Plant (U.S. EPA, 2024m).

5.4 Legacy Wastewater

For the 2024 final rule, the EPA estimated costs for plants to install and operate CP treatment for legacy wastewater. The EPA included the following treatment components:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems for lime, organosulfide, ferric chloride, and polymers.
- Mercury analyzer.
- Compliance monitoring (including sample collection and analysis).
- Solids handling (sludge holding tank and filter press).
- Transportation and disposal of solids in a landfill.

Section 5.4.1 describes the process for developing the legacy wastewater cost calculation inputs.

5.4.1 Legacy Cost Calculation Inputs

To estimate plant-level post-compliance costs of implementing treatment technologies for legacy wastewater, the EPA developed a cost calculation database. This database combines plant-specific input values, including wastewater flow rates and landfill disposal locations (on-site or off-site), with the relationships between costs and legacy flow rates described in Section 5.4.2 to estimate post-compliance costs for each plant (ERG, 2024c). For the 2024 final rule, the EPA used input data compiled from annual inspection reports, annual groundwater monitoring reports, and closure plans for surface impoundments containing legacy CCR. This section describes the EPA's methodology.

Population

The EPA categorized surface impoundments containing legacy CCR material into three groups:

- Remaining open—surface impoundments with composite liners.
- In closure process—surface impoundments greater than or equal to 40 acres in surface area without composite liners.
- Not considered—surface impoundments with surface area less than 40 acres, without composite liners, and expected to close prior to implementation of the 2024 final rule.

The EPA included any CCR surface impoundments in the "remaining open" group that had not yet started the closure process as of ORCR's September 2023 Comprehensive Compliance Report (U.S. EPA, 2023b). The EPA assumed that any surface impoundment that had started the closure process by that point will complete dewatering as of the compliance date in the 2024 final rule (December 31, 2029); therefore, costs and loadings were only estimated for plants that were classified as remaining open.

Legacy wastewater flows include both surficial (or free) water removed from surface impoundments and wastewater removed from saturated CCR material during the dewatering process. For all surface impoundments classified as remaining open, the EPA used data from annual inspection reports to identify the volume of water and volume of CCR material. To calculate the total volume of legacy wastewater from each impoundment, the EPA first estimated the volume of wastewater that would be produced from dewatering the volume of CCR material. The EPA then added that volume of wastewater to the volume of surficial water. See the memorandum *Legacy Wastewater at CCR Surface Impoundments* (U.S. EPA, 2024a) for details on these estimates.

Flow Rate

The EPA estimated legacy wastewater flow using plant-specific and surface impoundment-specific information on legacy wastewater volume and closure duration (*e.g.,* calendar time available for the dewatering process). For closure duration, the EPA used information from closure plans. The EPA adjusted these closure durations as follows:

- The EPA used a maximum closure period of seven years (*e.g.,* the duration of a CCR permit cycle plus a two-year extension). For any closure described in a closure plan as being longer than seven years, the EPA used seven years to estimate wastewater flow rate.
- Where no closure duration data were available, the EPA used seven years to estimate wastewater flow.

Based on legacy wastewater volume and closure duration, the EPA calculated a legacy wastewater flow in GPD. This legacy wastewater flow was used to estimate both compliance costs and pollutant loadings.

Treatment-in-Place Data

The EPA did not identify any existing treatment for legacy wastewater.

Landfill Data

The EPA used the same population of landfills as described in Section 5.3.1. Plants with an active or inactive landfill incurred on-site transportation and disposal costs; all other plants incurred costs for off-site transportation and disposal.

5.4.2 Cost Methodology for CP

To estimate CP costs for legacy wastewater, the EPA used the methodology described for CRL in Section 5.3.2. The EPA used the legacy wastewater flow rate in GPD, described in Section 0, in place of the CRL flow rate.

5.5 Summary of National Engineering Costs for Regulatory Options

To estimate total industry compliance costs for each regulatory option, the EPA first estimated plant-level compliance costs (described in the subsections above) for all technologies evaluated for FGD wastewater, BA transport water, CRL, and legacy wastewater. Next, the EPA estimated EGU-level costs (including capital costs, O&M costs, one-time costs, and 5-, 6-, and 10-year recurring costs) using the equations described in Table 10Table 10.

Table 10. EGU Cost Estimation by Wastestream

Wastestream	EGU Equation
FGD wastewater	Unit flow fraction: FGD system purge flow (GPD) ÷ plant-level purge flow (GPD) × EGU capacity (MW) ÷ FGD system capacity (MW) EGU cost: unit flow fraction × plant-level cost (2023$)
BA transport water	EGU cost: EGU capacity (MW) ÷ plant capacity (MW) × plant-level cost (2023$)
CRL	EGU cost: EGU capacity (MW) ÷ plant capacity (MW) × plant-level cost (2023$)
Legacy wastewater	EGU cost: EGU capacity (MW) ÷ plant capacity (MW) × plant-level cost (2023$)

For each EGU, the EPA chose the appropriate technology cost to coincide with the regulatory option being evaluated. See the preamble for details on the combinations of wastestreams and treatment technologies based on the regulatory option. The EPA then summed the EGU-level costs for only those EGUs included in each regulatory option to estimate total industry-level regulatory option costs. See the *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule* memorandum for the details, broken out by EGU, on technologies selected for each regulatory option and estimates of compliance costs (U.S. EPA, 2024o).[33]

Table 11, Table 12, Table 13, and Table 14 present the total industry compliance cost estimates for FGD wastewater, BA transport water, CRL, and legacy wastewater, respectively, by regulatory option. For each wastestream, the number of plants incurring costs under each evaluated option is also included. Table 15 presents the aggregated, industry-level compliance costs by regulatory option. All cost estimates are expressed in pre-tax 2023 dollars and represent costs that would be incurred once all plants and EGUs achieved 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).

For the final rule, the EPA also estimated an upper and lower bound to evaluate the potential costs associated with unmanaged CRL. The upper bound estimates use proxies for the factors that make unmanaged CRL more likely to be subject to incurring compliance costs under the final rule. The lower bound estimates account for additional scenarios that may result in less CCR units than the actual population impacted by the final rule. Table 16 presents the average cost estimates for the upper and lower bound analyses, further detailed in the preamble and the EPA's memorandum *Evaluation of Unmanaged CRL* (U.S. EPA, 2024).

Table 11. Estimated Cost of Implementation for FGD Wastewater by Regulatory Option (in Millions of Pre-tax 2023 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Cost	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost
Baseline	28	$0	$0	$0	NA	NA	NA
A	28[a]	$1,310	$94.2	$1.37	NA	NA	NA
B	28[a]	$1,310	$94.2	$1.37	NA	NA	NA
C	28[b]	$1,500	$107	$1.68	NA	NA	NA

Abbreviation: NA (not applicable).

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

a—Seven of these plants incur zero cost, meaning that there are 21 plants with nonzero estimated costs for implementation of Regulatory Options A and B.

b—Three of these plants incur zero cost, meaning that there are 25 plants with nonzero estimated costs for implementation of Regulatory Option C.

[33] The EPA made adjustments to select EGUs following final regulatory option cost estimation. Refer to the *Updates to Estimated Compliance Costs and Pollutant Loadings* memorandum for more information (U.S. EPA, 2024p).

Table 12. Estimated Cost of Implementation for BA Transport Water by Regulatory Option (in Millions of Pre-tax 2023 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Cost	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost[a]
Baseline	34	$0	$0	NA	$0	NA	$0
A	34[b]	$173	$9.68	NA	$0.604	NA	($1.39)
B	34[b]	$173	$9.68	NA	$0.604	NA	($1.39)
C	34[c]	$235	$16.9	NA	$0.604	NA	($1.39)

Abbreviation: NA (not applicable).

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

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

b—Seven of these plants incur zero cost, meaning that there are 27 plants with nonzero estimated costs for implementation of Regulatory Options A and B.

c—One of these plants incurs zero cost, meaning that there are 33 plants with nonzero estimated costs for implementation of Regulatory Option C.

Table 13. Estimated Cost of Implementation for CRL by Regulatory Option (in Millions of Pre-tax 2023 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Cost	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost
Baseline	90	$0	$0	$0	NA	$0	NA
A	90	$1,130	$54.5	$0	NA	$12.7	NA
B	90	$1,770	$119	$7.01	NA	$6.18	NA
C	90	$2,160	$110	$0.762	NA	$0	NA

Abbreviation: NA: (not applicable).

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

Table 14. Estimated Cost of Implementation for Legacy Wastewater by Regulatory Option (in Millions of Pre-tax 2023 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Cost	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost
Baseline	17	$0	$0	NA	NA	$0	NA
A	17	$0	$0	NA	NA	$0	NA
B	17	$376	$24.7	NA	NA	$3.24	NA
C	17	$376	$24.7	NA	NA	$3.24	NA

Abbreviation: NA: (not applicable).

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

Table 15. Estimated Cost of Implementation by Regulatory Option (in Millions of Pre-tax 2023 Dollars)

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One-Time Cost	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost[a]
Baseline	112	$0	$0	$0	$0	$0	$0
A	112[b]	$2,610	$158	$1.37	$0.604	$12.7	($1.39)
B	112[c]	$3,630	$248	$8.38	$0.604	$9.42	($1.39)
C	112[c]	$4,260	$258	$2.44	$0.604	$3.24	($1.39)

Abbreviation: NA: (not applicable).

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

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

b—Seven of these plants incur zero cost, meaning that there are 105 plants with nonzero estimated costs for implementation of Regulatory Option A.

c—One of these plants incurs zero cost, meaning that there are 111 plants with nonzero estimated costs for implementation of Regulatory Options B and C.

Table 16. Estimated Average Cost of Implementation for Unmanaged CRL for all Regulatory Options (in Millions of Pre-tax 2023 Dollars)

Analysis	Capital Cost	Annual O&M Cost	One-Time Cost	5-Year Recurring Cost	6-Year Recurring Cost	10-Year Recurring Cost
Upper Bound	$4,230	$463	NA	NA	$13	NA
Lower Bound	$880	$99	NA	NA	$3	NA

Abbreviation: NA: (not applicable).

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

6. Pollutant Loadings and Removals

This section describes the annual pollutant discharge loading estimates for the steam electric power generating industry, as well as estimated pollutant loading removals associated with the 2024 final rule. Estimates for the 2024 final rule build on the pollutant loadings and removals calculations for regulated wastestreams from the 2015 and 2020 rules. Section 10 of the 2015 Technical Development Document (2015 TDD) includes pollutant loadings and removals estimates for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, and combustion residual leachate (CRL) (U.S. EPA, 2015a). Section 6 of the 2020 Supplemental TDD estimates FGD wastewater and BA transport water pollutant removals as the change in loadings from the 2015 to the 2020 regulatory requirements. For this 2024 final rule, the U.S. Environmental Protection Agency (EPA) estimated pollutant loadings and removals for the four wastestreams for which this rule is establishing new requirements (FGD wastewater, BA transport water, CRL, and legacy wastewater). The EPA evaluated loadings and removals for the same industry population for which it estimated regulatory compliance costs (refer to Section 5 for the industry population evaluated for this rule). The EPA estimated baseline and post-compliance pollutant loadings and pollutant removals as follows:

- *Baseline loadings*. Pollutant loadings, in pounds per year, in wastewater discharged to surface water or through publicly owned treatment works (POTWs) to surface water under 2020 final rule conditions. For FGD wastewater and BA transport water, baseline loadings characterize wastewater discharged from plants assumed to be in full compliance with the requirements of the 2020 rule; for CRL and legacy wastewater, baseline loadings characterize current discharges.
- *Post-compliance loadings*. Pollutant loadings, in pounds per year, in wastewater discharged to surface water or through POTWs to surface water after full implementation of the 2024 final rule technology options. The EPA estimated post-compliance pollutant loadings with the expectation that all steam electric power plants subject to the requirements of the 2024 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.

This section describes the EPA's methodology for estimating plant-specific pollutant loadings and removals as well as industry-level results for each of the evaluated regulatory options:

- General methodology for estimating pollutant removals (Section 6.1).
- FGD wastewater (Section 6.2).
- BA transport water (Section 6.3).
- CRL (Section 6.4).
- Legacy wastewater (Section 6.5)
- Summary of industry-level baseline and regulatory option loadings and removals (Section 6.6).

6.1 General Methodology

For each plant discharging FGD wastewater, BA transport water, CRL, and/or legacy wastewater, the EPA estimated plant-level baseline loadings and post-compliance loadings and removals for each of the technology options described in Section 5. The EPA used sampling data collected in support of the 2015 rule and 2020 rule to characterize baseline and post-compliance pollutant concentrations, including data from the EPA's sampling program (described in Section 3 of the 2015 TDD), the Steam Electric Survey, public comments, industry submissions, and publicly available data sources. For CRL, the EPA received additional industry submissions in response to the 2023 proposed rule voluntary request and aggregated these data with prior data to characterize baseline pollutant concentrations (refer to Section 6.4 for additional details). The EPA evaluated these data sources to identify analytical data that meet its acceptance criteria for inclusion in analyses for characterizing discharges of FGD wastewater, BA transport water, CRL, and legacy wastewater. The EPA's acceptance criteria include:

- Sample locations must be unambiguous and clearly described such that the sample can be categorized by wastestream and level of treatment (*e.g.,* untreated, partially treated).
- Analytical data must provide enough information to identify units of measure and determine usability in the EPA's analyses.
- Analytical data must represent individual sample results, rather than average results for multiple plants or long-term averages for single plants.[34]
- Analytical data must not be duplicative of other accepted data.
- Sample analyses must be done using accepted analytical methods.
- Nondetect results are not acceptable if no detection or quantitation limit is provided.
- Sample results must represent total results for a pollutant (*i.e.,* dissolved results are not acceptable except for total dissolved solids).
- For biphasic samples, sample results must include both phases.

To ensure analytical data were representative, the EPA excluded data that did not meet the acceptance criteria as they were not fit for use in estimating pollutant loadings. Sections 6.2.2, 6.3.2, 6.4.2, and 6.5.2 describe additional wastestream-specific data acceptance criteria, if applicable, and present the average discharge pollutant concentrations used to estimate baseline and post-compliance loadings for FGD wastewater, BA transport water, CRL, and legacy wastewater, respectively.

First, the EPA calculated baseline loadings and post-compliance loadings for each plant using the plant-specific wastewater flow for the wastestream (as described in Section 5) and average pollutant concentrations for the specific wastestream using the following equation:

$$Loading_{pollutant}\ (\text{lb/year}) = \text{flow rate} \times \text{discharge days} \times Conc_{pollutant} \times (2.20462\ \text{lb}/10^9\ \mu\text{g}) \times (1{,}000\ \text{L}/264.17\ \text{gallons})$$

Where:

flow rate	=	Reported flow rate of the wastestream being discharged, in gallons per day, from the plant.
discharge days	=	Number of days per year the wastestream is discharged from the plant.
$Conc_{pollutant}$	=	Concentration of a specific pollutant in the wastestream, in micrograms per liter (µg/L). Refer to Table 18 for FGD wastewater, Table 19 for BA transport water, Table 20 for CRL, and Table 21 for legacy wastewater.

The EPA identified several plants that reported transferring wastewater to POTWs rather than directly discharging to surface waters. For these plants, the EPA adjusted the baseline and post-compliance loadings to account for pollutant removals expected during treatment at a well-operated POTW for each

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

pollutant, shown in Table 17. The EPA used the following equation to adjust baseline and post-compliance loading estimates for each pollutant to account for removals achieved by the POTW:

$$\text{Loading}_{\text{pollutant\_indirect}} \text{ (lb/year)} = \text{Loading}_{\text{pollutant}} \times [1 - (\text{Removal}_{\text{POTW}}/100)]$$

Where:

$Loading_{pollutant}$	=	Estimated pollutant loading from a specific pollutant if it was being discharged directly to surface water, in pounds per year.
$Removal_{POTW}$	=	Estimated percentage of the pollutant loading that would be removed by a POTW (see Table 17).

Finally, the EPA calculated pollutant removals (*i.e.,* the change in pollutant loadings) for each plant by subtracting the baseline loadings from the post-compliance loadings, as shown in the following equation:

$$Removal_{pollutant} \text{ (lb/year)} = Loading_{post\text{-}compliance} - Loading_{baseline}$$

Where:

$Loading_{post\text{-}compliance}$	=	Estimated pollutant loading discharged for a specific pollutant for the post-compliance technology option, in pounds per year (accounting for removals achieved by POTWs, where appropriate).
$Loading_{baseline}$	=	Estimated pollutant loading discharged for a specific pollutant for the baseline technology option, in pounds per year (accounting for removals achieved by POTWs where appropriate).

Table 17. POTW Removals

Pollutant	Median POTW Removal Percentage
Aluminum	91.0%
Ammonia	39.0%
Antimony	66.8%
Arsenic	65.8%
Barium	55.2%
Beryllium	61.2%
Biochemical oxygen demand	Not available
Boron	Not available
Cadmium	90.1%
Calcium	Not available
Chemical oxygen demand	Not available
Chloride	Not available
Chromium	80.3%
Chromium, hexavalent	Not available
Cobalt	10.2%
Copper	84.2%
Cyanide, total	Not available
Iron	Not available
Lead	77.5%
Magnesium	Not available
Manganese	40.6%

Table 17. POTW Removals

Pollutant	Median POTW Removal Percentage
Mercury	90.2%
Molybdenum	Not available
Nickel	51.4%
Nitrate/nitrite as N	90.0%
Nitrogen, Kjeldahl	Not available
Phosphorus, total	Not available
Selenium	34.3%
Silver	88.3%
Sodium	Not available
Sulfate	Not available
Thallium	53.8%
Tin	Not available
Titanium	Not available
Total dissolved solids	Not available
Total suspended solids	Not available
Vanadium	8.3%
Zinc	79.1%

Source: ERG, 2005.

Note: The EPA received public comment on the 2023 proposed rule regarding updating the POTW removals used in its pollutant loadings analysis. Refer to Code 12 (FGD Wastewater—Data) in the comment response document for additional details (U.S. EPA, 2024q).

6.2 FGD Wastewater

For each plant discharging FGD wastewater, as described in Section 5, the EPA estimated pollutant loading values for two conditions:

- Baseline conditions, in which plants were assumed to comply with the 2020 rule—*i.e.*, chemical precipitation (CP) followed by low residence time reduction (CP+LRTR) or membrane filtration (Voluntary Incentives Program [VIP] plants only).
- Compliance with the zero-discharge technology option (*i.e.,* zero loadings for either membrane filtration or spray dryer evaporator technologies).

As noted in Section 6.1, the EPA calculated pollutant loadings using a flow rate multiplied by an average pollutant concentration. For the 2024 rule, the EPA used data from the 2020 rule to characterize pollutant concentrations in FGD wastewater. See the *Development Memo for FGD Wastewater Data in the Analytical Database* for details on the acceptance criteria used to generate the EPA's FGD analytical data set (ERG, 2015a). Table 18 presents the average effluent concentrations for CP+LRTR treatment. Regarding membrane treatment, the EPA expects that plants will choose to reuse permeate as FGD scrubber make-up; therefore, membrane filtration average effluent concentrations were assumed to be zero.

As noted in the 2020 Supplemental TDD, the EPA supplemented these analytical data with additional data for bromide and iodide. Because sampling data for these pollutants were insufficient, the EPA developed a methodology to estimate pollutant loadings from both the naturally occurring bromine and iodine in the coal burned and any bromide or iodide additives that were being used for mercury emission control at each plant. This methodology is described in the *FGD Halogen Loadings from Steam Electric Power Plants Memorandum* – 2024 Final Rule (U.S. EPA, 2024r).

Section 6.2.1 describes FGD wastewater flow rates used for pollutant loading calculations, and Section 6.2.2 discusses the EPA's methodology for estimating baseline and post-compliance loadings.

Table 18. Average CP+LRTR Effluent Concentrations

Pollutant	Average Concentration (µg/L)
Conventional Pollutants	
Total suspended solids	8,590
Priority Pollutants	
Antimony	4.25
Arsenic	5.83
Beryllium	1.34
Cadmium	4.21
Chromium	6.45
Copper	3.78
Cyanide, total	949
Lead	3.39
Mercury	0.0507
Nickel	6.30
Selenium	5.72
Thallium	9.81
Zinc	20.0
Nonconventional Pollutants	
Aluminum	120
Ammonia as N	6,850
Barium	140
Boron	225,000
Calcium	1,920,000
Chloride	7,120,000
Cobalt	9.30
Iron	110
Magnesium	3,370,000
Manganese	12,500
Molybdenum	125
Nitrate/nitrite as N	647
Phosphorus, total	319
Sodium	276,000
Titanium	9.30
Total dissolved solids	24,100,000
Vanadium	12.6

Sources: ERG, 2024d.

Note: Concentrations are rounded to three significant figures.

6.2.1 FGD Wastewater Flows

To estimate all pollutant loadings, the EPA used the same set of flow rates as described in Section 5.1.1 for compliance cost estimates. As in the 2020 rule, the EPA used optimized flow rates, consistent with the operation and maintenance compliance cost assumption that plants will choose to optimize FGD flow through their treatment systems.

6.2.2 Baseline and Post-compliance Loadings

The EPA multiplied the average effluent pollutant concentrations shown in Table 18 by the plant-specific FGD wastewater optimized flow rate described in Section 6.2.1 to calculate the pollutant loadings discharged to surface water for each plant. The EPA identified one plant transferring FGD wastewater to a POTW. The EPA expects that this plant will continue to transfer the wastewater under baseline conditions. The EPA therefore adjusted the baseline loadings to account for pollutant removals associated with POTW treatment, as described in Section 6.1.

Baseline Loadings

For all plants discharging FGD wastewater that did not opt into the VIP, the EPA used CP+LRTR concentrations from Table 18 to represent baseline. The EPA assumes that plants subject to the 2020 rule have installed the best available technology economically achievable (BAT), CP+LRTR, or equivalent technology.

For plants that opted into the VIP, the EPA estimated baseline loadings of zero, reflecting membrane filtration treatment and reuse. The EPA assumes that plants will choose to reuse membrane permeate within the plant rather than discharge permeate and monitor the effluent for compliance with NPDES (National Pollutant Discharge Elimination System) permit limitations, due to the cost associated with monitoring and potential for noncompliance.

CP+LRTR Post-compliance Loadings

For the CP+LRTR technology option, the EPA assumed that plants already comply with the 2020 rule and estimated post-compliance loadings identical to baseline loadings.

Zero-Discharge Post-compliance Loadings

For the zero-discharge technology option, the EPA estimated post-compliance loadings of zero for all plants discharging FGD wastewater.

6.3 BA Transport Water

For each plant discharging BA transport water, as described in Section 5, the EPA estimated three pollutant loading values:

- Baseline conditions based on a high recycle rate system with a purge.
- Compliance with the dry handling or high recycle rate BA system with a purge (high recycle rate, or HRR) technology option.
- Compliance with the zero-discharge technology option.

As noted in Section 6.1, pollutant loadings were calculated using a flow rate multiplied by average pollutant concentrations. For the 2024 rule, the EPA used data from the 2020 rule to characterize pollutant concentrations in BA transport water. See *Development of the Bottom Ash Transport Water Analytical Dataset and Calculation of Pollutant Loadings for the Steam Electric Effluent Guidelines Proposed Rule* for details on the EPA's data sources, acceptance criteria, and development of the analytical data set used to characterize BA transport water (ERG, 2019b).

Data for BA transport water were 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 surface impoundment effluent. Because of this, the EPA has additional acceptance criteria specific to BA transport water samples:

- A sample must be at least 75 percent BA transport water by volume and not include any contribution of fly ash (FA) transport water.

- The sample must be representative of actual BA surface impoundment effluent collected during full-scale, typical plant operations.

The EPA used the BA transport water analytical data to calculate an industry average concentration for each pollutant present.[35] Table 19 presents the average effluent concentrations for pollutants present in BA transport water.

Table 19. Average BA Transport Water Effluent Concentrations

Pollutant	Average Concentration (µg/L)
Conventional Pollutants	
Chemical oxygen demand	20,800
Total suspended solids	13,400
Priority Pollutants	
Antimony	17.3
Arsenic	9.32
Cadmium	0.721
Chromium	5.08
Copper	3.95
Lead	10.4
Mercury	0.102
Nickel	17.5
Selenium	12.3
Thallium	1.13
Zinc	33.8
Nonconventional Pollutants	
Aluminum	854
Barium	106
Boron	5,310
Bromide	5,100
Calcium	154,000
Chlorides	321,000
Cobalt	9.19
Iron	676
Magnesium	55,700
Manganese	153
Molybdenum	28.3
Nitrate/nitrite as N	1,670
Phosphorus	222
Potassium	19,600
Silica	8,160
Sodium	119,000
Strontium	1,430
Sulfate	504,000
Sulfite	3,920

[35] BA surface impoundments typically include other wastestreams (*e.g.,* low-volume wastewaters, cooling water); as a result, the effluent concentrations due to BA transport water are likely suppressed somewhat due to dilution. Because of this, baseline pollutant loadings and post-compliance pollutant loadings are underestimated to some degree. Nevertheless, the EPA considers 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/pretreatment standards for existing sources (PSES) limitations.

Table 19. Average BA Transport Water Effluent Concentrations

Pollutant	Average Concentration (µg/L)
Titanium	35.9
Total dissolved solids	1,290,000
Total Kjeldahl nitrogen	968
Vanadium	10.1

Sources: ERG, 2024e.

Notes: Concentrations are rounded to three significant figures. The EPA did not calculate average concentrations for pollutants for which all sample results are less than the quantitation limit.

The EPA identified ammonia (as N) as a pollutant present in BA transport water; however, the EPA excluded this parameter from the calculation of pollutant loadings to avoid double-counting of nitrogen compounds. The EPA has no data on iodine concentrations in BA transport water and therefore could not calculate an average pollutant concentration.

6.3.1 BA Transport Water Flows

To estimate pollutant loadings, the EPA used the same set of flow rates as described in Section 5.2.1 for compliance cost estimates. For baseline loadings, where it assumed compliance with the 2020 rule (*i.e.,* high recycle rate), the EPA estimated the purge flows as 10 percent of the volume of the total wetted, active components of the remote mechanical drag system (MDS). In evaluating regulatory options for which the technology basis is still high recycle rate (*e.g.,* electric generating units [EGUs] permanently ceasing coal combustion by 2034), the EPA estimated purge flows as 2 percent of the volume of the total wetted, active components of the remote MDS (which the EPA found to be more consistent with current industry operations). This resulted in pollutant loading reductions for seven plants that the EPA estimates will not incur additional compliance costs.

6.3.2 Baseline and Post-compliance Loadings

For baseline and post-compliance loadings, the EPA calculated EGU-level pollutant loadings by multiplying the average concentration of each pollutant in Table 19 by the EGU-level discharge flow rate. Using the EGU-level loadings, the EPA then calculated the baseline and post-compliance loadings for each plant as the sum of pollutant loadings for all EGUs. The EPA did not identify any plants transferring BA transport water to a POTW.

Baseline Loadings

For all plants discharging BA transport water, the EPA used BA transport water concentrations from Table 19 to represent baseline. The EPA assumed that plants subject to the 2020 rule have installed BAT (*i.e.*, HRR using an MDS or remote MDS, both with a purge option). If a plant is in the low utilization subcategory, the EPA assumed post-compliance loadings reflecting a surface impoundment plus best management practice (BMP) plan.[36]

HRR Post-compliance Loadings

Under the HRR technology option, which would allow plants to discharge a portion of their BA transport water, the EPA estimated loadings associated with MDS and remote MDS installations with a purge. The EPA assumed that plants that already have HRR technologies installed have post-compliance loadings identical to baseline loadings.

[36] The EPA assumed that any plant subject to the implementation of a BMP plan under the 2020 rule subcategories will continue to discharge BA transport water consistent with current operations (*i.e.*, the BA sluice flow rate). The 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 (U.S. EPA, 2015a).

Zero-Discharge Post-compliance Loadings

Under the zero-discharge technology option, the EPA estimated pollutant loadings associated with MDS and closed-loop remote MDS installations. (Closed-loop remote MDS installations use reverse osmosis systems to allow for complete recycle.) The EPA estimated post-compliance loadings of zero for all plants.

6.4 CRL

The EPA estimated CRL pollutant loadings under baseline conditions as well as for the CP technology option and zero discharge.

As described in the 2015 TDD, the EPA combined data from 26 landfills and 15 surface impoundments reported in the Steam Electric Survey to estimate the average effluent concentration of CRL (U.S. EPA, 2015a). The EPA used all data provided by the plants in the Steam Electric Survey, except for the following:

- For any value reported as less than the quantitation limit, the EPA assumed the concentration was equal to half the quantitation limit provided.
- If the plant did not provide a quantitation limit, the EPA assumed the concentration was equal to the method detection limit.

The EPA also obtained untreated landfill CRL sampling data in response to the 2023 proposed rule voluntary request, as described in Section 2.2.2. The EPA followed the same data quality criteria as described in this section and Section 6.1, with the following additional considerations:

- The EPA accepted sampling data that used solid waste leachate analytical methods accepted the data as long as the methodology is approved in 40 CFR 136 for the corresponding analyte (e.g., EPA Method 7470A for mercury is a cold-vapor atomic absorption procedure).
- The EPA excluded nondetect mercury observations that were sampled using methods other than 1631E, because those methods are insufficiently sensitive.
- When an original sample could be identified, the EPA included any field duplicate results and averaged the duplicate with its original sample.
- The EPA excluded data from retired landfills.

The EPA first calculated average analyte concentrations for each landfill. Then, the EPA calculated plant-level average analyte concentrations using all landfill and surface impoundment average analyte concentrations at a particular plant. Of the landfills with 2023 voluntary request data that met the data quality criteria, none had data from both the 2023 voluntary request and the 2015 rule. However, there were three plants that had data from both the 2015 rule and the 2023 voluntary request, so the EPA took the individual averages for all landfills and surface impoundments at a plant from both data sources and calculated a new plant-level average. Finally, the EPA calculated industry-level average concentrations using all plant-level average concentrations (those from the 2015 rule, those from the 2023 proposed rule, and the combined 2015/2023 rule averages for three plants). The EPA then updated the untreated CRL average concentration data set for calculating baseline loadings for the 2024 rule, as shown in Table 20. Refer to the *CRL Analytical Data Evaluation—2024 Final Rule* memorandum for additional details on the data sources, data processing, and data quality criteria (U.S. EPA, 2024s).

In 2015, the EPA identified one plant operating a biological treatment system to treat landfill CRL (combined with FGD wastewater) and one plant building a biological treatment system to treat its landfill CRL. Through the 2023 proposed rule public comments, the EPA also identified two plants that use CP to treat CRL. As described in Section 5.3.1, the EPA accounted for this treatment-in-place information in the 2024 analyses.

The EPA does not have analytical data from steam electric power plants using CP or biological treatment to treat CRL; therefore, the Agency used the same methodology as that of the 2015 rule, transferring the average FGD effluent concentrations for CP and biological treatment. In cases where the average concentration of the untreated CRL was less than the FGD treated concentration for CP or biological treatment, the EPA assumed that the treated concentration was equal to the untreated CRL average concentration. The EPA did not calculate removals of these pollutants by the wastewater treatment system. These concentrations are also presented in Table 20.

Table 20. Average CRL Pollutant Concentrations

Pollutant	Untreated CRL Average Concentration (µg/L)	Chemical Precipitation Average Concentration (µg/L)	Biological Treatment Average Concentration (µg/L)
Conventional Pollutants			
Total suspended solids	33,900	8,590	8,590
Priority Pollutants			
Antimony	3.82	3.75	3.75
Arsenic	32.2	5.83	5.83
Cadmium	8.17	4.21	4.21
Chromium	1,700	6.45	6.45
Copper	9.44	3.78	3.78
Mercury	0.940	0.139	0.0507
Nickel	45.6	9.11	6.30
Selenium	93.8	93.8	5.72
Thallium	1.55	1.16	1.16
Zinc	133	20.0	20.0
Nonconventional Pollutants			
Aluminum	3,190	120	120
Barium	148	53.2	53.2
Boron	22,000	22,000	22,000
Calcium	490,000	408,000	408,000
Chlorides	566,000	413,000	413,000
Cobalt	63.4	9.30	9.30
Iron	23,000	110	110
Magnesium	99,800	99,800	99,800
Manganese	2,840	2,720	2,720
Molybdenum	1,480	125	125
Sodium	328,000	276,000	276,000
Sulfate	1,630,000	1,240,000	1,240,000
Total dissolved solids	3,570,000	3,500,000	3,500,000
Vanadium	1,570	12.6	12.6

Sources: U.S. EPA, 2015a; ERG 2023c, 2023d.

As described in Section 3.2.3, the EPA also notes that unlined landfills and surface impoundments potentially discharge unmanaged CRL that may be covered under the ELGs when it is determined on a case-by-case basis to be the functional equivalent of a direct discharge. To evaluate the potential costs and loads of such discharges, the EPA conducted a bounding analysis, documented in its memorandum *Evaluation of Unmanaged CRL* (U.S. EPA, 2024). The EPA presents the pollutant loadings for unmanaged CRL in Section 6.6.

6.4.1 CRL Flows

As described in Section 5.3.1, the EPA used the same methodology from the 2015 rule to estimate CRL flow rates for the 2024 rule, with estimates deriving from the Steam Electric Survey. For plants without flow rate data, the EPA used the median CRL flow per landfill (active or inactive) or surface impoundment (refer to Section 5.3.1).

6.4.2 Baseline and Post-compliance Loadings

To estimate baseline and post-compliance loadings for the 2024 final rule, the EPA multiplied the appropriate average effluent pollutant concentrations from Table 20 by the CRL flow rate to calculate the pollutant loadings for each plant. All calculations, including baseline and the technology options, use the same CRL flow rate. The EPA estimated loadings using both the CRL flow and the post-closure CRL flow. The EPA adjusted pollutant loadings for plants discharging to a POTW to account for additional removals achieved by the POTW.

Baseline Loadings

For all plants except those with treatment in place, the EPA estimated baseline loadings using the untreated concentrations shown in Table 20.

For the two plants with biological treatment in place for CRL, the EPA used a methodology consistent with the 2015 rule and transferred the effluent concentrations from the FGD biological treatment, shown in Table 20, to calculate baseline loadings. For the two plants with CP treatment in place for CRL (identified through public comments), the EPA similarly transferred the FGD CP treatment effluent concentrations from Table 20 to calculate baseline loadings.

CP Post-compliance Loadings

To estimate CP post-compliance loadings for those plants without CRL treatment in place, the EPA used CRL flow rates and the CP effluent concentrations shown in Table 20. For the four plants with treatment in place, the EPA estimated option loadings identical to baseline loadings.

Zero-Discharge Post-compliance Loadings

For the zero-discharge technology option, the EPA estimated post-compliance loadings of zero for all plants discharging CRL.[37]

6.5 Legacy Wastewater

The EPA estimated legacy wastewater pollutant loadings under baseline conditions as well as for the CP technology option. The EPA used data collected in support of the 2015 ELG to characterize effluent concentrations for surface impoundments including FA, BA, combined ash (CA), and FGD wastewater. See Sections 11 and 12 of the *Final Steam Electric Incremental Costs and Pollutant Loadings Report* (ERG, 2015b) for details on how FGD wastewater and ash transport water characterization data were collected and edited to characterize effluent from surface impoundments containing these coal combustion residuals (CCRs).

As with CRL, the EPA does not have analytical data from steam electric power plants using CP to treat legacy wastewater; therefore, the EPA used a similar approach to that described in Section 6.4,

[37] Following closure of all coal-fired EGUs, plants may discharge membrane filtration permeate and/or thermal evaporation distillate. This allows plants to continue treating CRL that may not have an on-site use for the permeate/distillate. Although the EPA is allowing plants to discharge following closure, plants will still be required to meet the 2020 rule VIP limitations for permeate from a membrane filtration system or the 2015 rule new source performance standards (NSPS) limitations for distillate from a thermal treatment system (refer to preamble Section VII.B.3 for details).

transferring the average FGD effluent concentrations for CP. Since characterization data for FGD surface impoundment effluent, FA surface impoundment effluent, BA surface impoundment effluent, CA surface impoundment effluent, and CP treatment include different types of analytes, pollutant loadings were only generated for analytes that are consistent across all data sets (26 total). See Table 21 for the average pollutant concentrations used to characterize untreated legacy wastewater and CP treated legacy wastewater.

Table 21. Average Legacy Wastewater Pollutant Concentrations

Pollutant	FGD Surface Impoundment Effluent Concentration (µg/L)	FA Surface Impoundment Effluent Concentration (µg/L)	BA Surface Impoundment Effluent Concentration (µg/L)	CA Surface Impoundment Effluent Concentration (µg/L)	FGD CP Effluent Concentration (µg/L)
Conventional Pollutants					
Total suspended solids	27,900	10,400	19,700	15,300	8,590
Priority Pollutants					
Arsenic	7.59	36.4	17.4	50.3	5.83
Cadmium	113	7.63	2.19	1.42	4.21
Chromium	17.8	27.4	5.59	21.6	6.45
Copper	21.8	68.8	13.9	21.9	3.78
Lead	4.66	13.7	12.1	7.52	3.39
Mercury	7.78	0.828	0.634	1.18	0.139
Nickel	878	30.5	16.5	19.1	9.11
Selenium	1,170	15.4	11.8	28.0	928
Thallium	13.7	10.3	89.4	31.0	9.81
Zinc	1,390	226	31.0	72.3	20.0
Nonconventional Pollutants					
Aluminum	2,080	2,230	1,240	1,200	120
Barium	303	121	110	188	140
Boron	243,000	6,630	541	1,960	225,000
Calcium	2,050,000	99,300	68,800	74,600	1,920,000
Chloride	7,120,000	12,800	28,100	16,300	7,120,000
Cobalt	183	5.67	14.5	6.00	9.30
Iron	1,510	855	1,420	601	110
Magnesium	3,370,000	13,600	34,500	15,300	3,370,000
Manganese	93,400	144	1,440	67.5	12,500
Molybdenum	125	483	29.7	142	125
Nitrate/nitrite as N	96,000	2,360	6,070	2,550	96,000
Phosphorus	319	71.8	204	196	319
Sodium	276,000	34,000	53,000	12,400	276,000
Titanium	27.1	4.83	40.9	22.8	9.30
Total dissolved solids	32,500,000	469,000	754,000	266,000	24,100,000

Source: U.S. EPA 2015a.

6.5.1 Legacy Wastewater Flows

The EPA estimated legacy wastewater flows as described in Section 5.4.1.

The EPA reviewed materials in the rulemaking record (*e.g.,* steam electric power generating industry questionnaire database) and publicly available information, including geographic information system (GIS) mapping, to identify the receiving waters for legacy discharges. See the EPA memorandum *Receiving Waters Characteristics Analysis and Supporting Documentation for the Environmental Assessment of the Final Supplemental Steam Electric Rule* (U.S. EPA, 2024n) for details on the analysis. Based on available information, the EPA identified plants that are currently zero discharge and assumed that legacy wastewater would be managed as zero discharge. The EPA identified all other plants as direct dischargers and assumed that their legacy wastewater would also be directly discharged.

6.5.2 Baseline and Post-compliance Loadings

To estimate baseline and post-compliance loadings for the rule, the EPA multiplied the appropriate average effluent pollutant concentrations from Table 21 by the plant-specific legacy wastewater flow rate to calculate the pollutant loadings for each plant. Calculations for both baseline and the CP technology option use the same legacy wastewater flow rate.

Baseline Loadings

For all plants, the EPA estimated baseline loadings using the untreated concentrations shown in Table 21. Where possible, the EPA used the CCR impoundment effluent data set (FGD wastewater, FA, BA, or CA) that matched the surface impoundment description based on closure plans or other surface-impoundment-specific data (*e.g.,* the EPA used the FGD wastewater data set where CCR impoundments were titled "FGD pond"). Where the CCR material could not be determined, the EPA used data from the Steam Electric Survey to determine the type of CCR in each surface impoundment and assigned the most appropriate data set (U.S. EPA, 2015). Lacking other data, where it determined a steam electric power plant had never operated a wet FGD system, the EPA assigned these surface impoundments the CA data set.

CP Post-compliance Loadings

To estimate CP post-compliance loadings for all plants, the EPA used plant-specific legacy wastewater flow rates and the CP effluent concentrations shown in Table 21.

6.6 Summary of Baseline and Regulatory Option Loadings and Removals

The EPA evaluated three regulatory options to control FGD wastewater, BA transport water, CRL, and legacy wastewater discharges. For each regulatory option, the EPA combined the wastestream-level pollutant loadings for baseline and each technology option to obtain total regulatory option loadings; the EPA also calculated pollutant removals as the difference between baseline and each regulatory option (ERG, 2024f). This section discusses the specific loadings and removals calculations for each regulatory option evaluated by the EPA. This section also presents aggregated industry-level loadings and removals for each wastestream and regulatory option.

The EPA applied different effluent limitations to the following:

- Steam electric EGUs with less than 50 megawatts of generating capacity.
- EGUs permanently ceasing coal combustion by 2034 (FGD wastewater, BA transport water, and CRL).

In calculating the pollutant loading estimates for each regulatory option, the EPA considered the subcategorizations established by each option. The preamble describes the subcategories and requirements applicable for each of the regulatory options evaluated by the EPA.

Table 22, Table 23, Table 24, and Table 25 present the EPA's estimated total industry pollutant loadings and removals for FGD wastewater, BA transport water, CRL, and legacy wastewater, respectively, in pounds per year for baseline and each regulatory option. Table 26 presents the EPA's aggregated, industry-level pollutant loadings and removals at baseline and each regulatory option. Pollutant loadings and removals presented in these tables are calculated as the sum of TDS and TSS. The EPA estimated the pollutant removals by subtracting the post-compliance loadings from the baseline loadings. The *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule* memorandum presents the baseline and post-compliance loadings for each wastestream and each regulatory option at the unit level (U.S. EPA, 2024o). Post-compliance loadings represent loadings once all plants and EGUs comply 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).

Although they were not part of the main regulatory option analysis, the EPA also estimated industry-level pollutant loadings for discharges of unmanaged CRL. The EPA estimates pollutant removals associated with discharges of unmanaged CRL could be between 3.62 and 16.4 million pounds annually.

Table 22. Estimated Industry-Level FGD Wastewater Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	655,000,000	—
A	74,600,000	580,000,000
B	74,600,000	580,000,000
C	—	655,000,000

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

Table 23. Estimated Industry-Level BA Transport Water Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	7,570,000	—
A	353,000	7,220,000
B	353,000	7,220,000
C	—	7,570,000

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

Table 24. Estimated Industry-Level CRL Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	48,100,000	—
A	46,900,000	1,200,000
B	3,500,000	44,600,000
C	—	48,100,000

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

Table 25. Estimated Industry-Level Legacy Wastewater Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	96,400,000	—
A	96,400,000	—
B	72,300,000	24,100,000
C	72,300,000	24,100,000

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

Table 26. Estimated Industry-Level Pollutant Loadings and Removals by Regulatory Option

Regulatory Option	Estimated Total Industry Loadings (lb/Year)	Estimated Total Industry Removals (lb/Year)
Baseline	807,000,000	—
A	218,000,000	589,000,000
B	151,000,000	656,000,000
C	72,300,000	735,000,000

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

7. Non-Water Quality Environmental Impacts

Eliminating or reducing one form of pollution can aggravate other environmental problems, an effect often referred to as a cross-media impact. Sections 304(b) and 306 of the Clean Water Act (CWA) require the EPA to consider non-water quality environmental impacts (NWQEIs), including energy impacts, associated with effluent limitations guidelines and standards (ELGs). Accordingly, the EPA considered the potential impacts of the regulatory options considered for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, combustion residual leachate (CRL), and legacy wastewater discharged from steam electric power plants on energy consumption (including fuel usage), air emissions, solid waste generation, and water use. Like the costs discussed in Section 5 and pollutant removals discussed in Section 6, the NWQEIs associated with the regulatory options evaluated for this rulemaking are measured as incremental changes from baseline (*i.e.,* the 2020 rule).

As described in Section 3.2.3, the EPA also notes that unlined landfills and surface impoundments potentially discharge unmanaged CRL that may be covered under the ELGs when they are determined on a case-by-case basis to be the functional equivalent of a direct discharge. To evaluate the potential NWQEIs of such discharges, the EPA conducted analyses documented in its memorandum *Evaluation of Unmanaged CRL* (U.S. EPA, 2024). The EPA presents the NWQEIs for unmanaged CRL throughout Section 7, following the main regulatory option analysis.

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 rule, the EPA considered whether there would be an associated incremental change in energy need compared to the baseline. That need varies depending on the regulatory option evaluated and the current operations of the plant. Therefore, as applicable, the EPA estimated the change in annual energy consumption in megawatt hours (MWh) for equipment added to the plant systems or in consumed fuel (gallons) for transportation or equipment operation. Specifically, the EPA estimated energy usage associated with operating equipment for the FGD wastewater treatment systems, BA handling systems, CRL, and legacy wastewater treatment systems considered for this rule.

- To estimate changes in energy consumption associated with operating FGD wastewater treatment equipment, the EPA developed relationships between FGD wastewater flow and energy usage for the following technologies: low residence time reduction (LRTR) biological treatment, membrane filtration, and spray dryer evaporator (SDE).
- To estimate energy usage for operating BA handling systems, the EPA developed relationships between electric generating unit (EGU) capacity and energy usage for the following technologies: mechanical drag system (MDS), remote MDS with a purge, and remote MDS with RO treatment of a slipstream to achieve complete recycle. The EPA estimated electrical energy use from horsepower ratings of system equipment (*e.g.,* pumps, mixers, silo unloading equipment) and energy usage data provided by wastewater treatment vendors. See the *Methodology for Estimating NWQEI for the 2024 Final Steam Electric ELGs* memorandum for additional details (U.S. EPA, 2024t).
- To estimate energy usage for operating CRL wastewater treatment systems, the EPA relied on the methodology developed for the chemical precipitation technology for FGD wastewater treatment as part of the 2015 and 2020 rules. For membrane filtration and SDE, the EPA also relied on the methodology used for FGD wastewater but estimated energy usage for the system sized to accommodate the CRL flow. The EPA summed plant-specific energy usage estimates to calculate the net change in annual energy consumption for the regulatory options considered for the rule; this information is presented in Table 27.

- To estimate energy usage for operating legacy wastewater treatment using CP, the EPA used the methodology from CRL, but estimated plant-level energy usage for CP treatment based on legacy wastewater flows. The EPA summed plant-specific energy usage estimates to calculate the net change in annual energy consumption for the regulatory options considered for the rule.

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 a remote MDS BA slipstream with an RO system to off-site disposal using a tanker truck. In general, the 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 the *Methodology for Estimating NWQEI for the 2024 Final Steam Electric ELGs* memorandum, 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 (U.S. EPA, 2024t). Table 27 shows the net change in national annual fuel consumption associated with the regulatory options compared to baseline (*i.e.,* the 2020 rule).

Table 27. Net Change in Annual Energy Use for the Regulatory Options Compared to Baseline

Non-Water Quality Impact	Net Change in Energy Use Associated with the ELG		
	Option A	Option B	Option C
Electrical energy usage (MWh)	182,000	309,000	436,000
Fuel (gallons per year)	97,600	116,000	151,000

Source: ERG, 2024g

Note: Values rounded to three significant figures.

The EPA estimates that energy use associated with discharges of unmanaged CRL could amount to as much as 280,000 MWh and 442 thousand gallons of fuel annually.

7.2 Air Emissions

The 2024 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 BA handling systems in compliance 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 more detail on air emission changes associated with the first two mechanisms and presents the estimated net change in air emissions associated with all three. See also the EPA's *Benefit and Cost Analysis for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for further discussion of the third mechanism (U.S. EPA, 2024u).

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 (NO_x). 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.[38] Conversely, decreasing energy use or less vehicle operation will result in decreased air pollution.

The EPA calculated air emissions resulting from the change in power requirements[39] using year-explicit emission factors estimated by the Integrated Planning Model (IPM)[40] 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. The EPA used detailed outputs for the 2035 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 limitations and pretreatment standards associated with the 2024 final rule.

The 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.

The EPA assumed that plants with capacity utilization rates (CUR) of 90.4 percent or less would generate the additional auxiliary electricity on site and therefore estimated emissions using plant-specific and year-explicit emission factors obtained from IPM outputs.[41]

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

Because the EPA ran IPM for the 2024 final rule only, the EPA used IPM emission factors calculated for the 2024 final rule to estimate changes in power requirements air emissions for all other regulatory options.

To estimate air emissions associated with operation of transport vehicles, the EPA used the MOVES4 model to generate air emission factors for NO_x, SO_2, CO_2, and CH_4. The EPA assumed the general input parameters such as the year of the vehicle and the annual mileage accumulation by vehicle class to develop these factors (U.S. EPA, 2024v). Table 28 lists the transportation emission factors for each air pollutant considered in the NWQEI analysis.

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[38] The EPA did not specifically evaluate N_2O emissions as part of the NWQEI analysis. To avoid double-counting air emission estimates, the EPA calculated only NO_x emissions, which would include N_2O emissions.

[39] Power requirements refers to the electricity needed to operate FGD wastewater treatment, BA handling, CRL, and/or legacy wastewater treatment technologies. Plants may generate this electricity on site or purchase the electricity from the grid.

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

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

Table 28. MOVES4 Emission Rates for Model Year 2010 Diesel-Fueled, Long-Haul Trucks Operating in 2024

Roadway Type	NO_x (Tons/mi)	SO_2 (Tons/mi)	CO_2 (Tons/mi)	CH_4 (Tons/mi)
Highway	3.20E-06	5.72E-09	0.0017	1.47E-08
Local	4.04E-06	5.93E-09	0.00176	2.00E-08

Source: MOVES4.0 (database version "movesdb20240104").

Abbreviations: mi (mile).

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

Road types: Restricted access roads are "Highway" and unrestricted access are "Local."

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

The 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 off-site disposal would travel to comply with limitations associated with the regulatory options. See the EPA's memorandum *Methodology for Estimating NWQEI for the 2024 Final Steam Electric ELGs* for more information on the specific calculations used to estimate transport distance and number of trips per year (U.S. EPA, 2024t). The changes in national annual air emissions associated with auxiliary electricity and transportation for each of the regulatory options are shown in Table 29.

Table 29. 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
NO_X (thousand tons/year)	0.045	0.090	0.104
SO_2 (thousand tons/year)	0.049	0.116	0.123
CO_2 (million metric tonnes/year)	0.063	0.126	0.146
CH_4 (thousand metric tonnes/year)	0.007	0.008	0.011

Source: ERG, 2024g

The EPA estimates that air emissions associated with discharges of unmanaged CRL could amount to as much as 0.048 million metric tonnes of CO_2, 0.022 thousand tons of NO_X, and 0.014 thousand tons of SO_2 annually.

The modeled output from IPM predicts changes in electricity generation due to compliance costs attributable to the regulatory options compared to baseline. These changes in electricity generation are, in turn, predicted to affect the amount of NOx, SO_2, and CO_2 emissions from steam electric power plants. A summary of the net change in annual air emissions associated with Option B for all three mechanisms are shown in Table 30. Similar to costs, the IPM from these options reflect the range of NWQEI associated with all three regulatory options. To provide some perspective on the estimated changes in annual air emissions, the EPA compared the estimated change in air emissions to the net amount of air emissions generated in a year by all steam electric power plants throughout the U.S. For a detailed breakout of each of the three sources of air emission changes, see the EPA's BCA (U.S. EPA, 2024u).

Table 30. Estimated Net Change in Industry-Level Air Emissions associated with Changes in Power Requirements, Transportation, and Electricity Generation for Option B Compared to Baseline

Non-Water Quality Impact	Change in Emissions—Option B	2020 Emissions by Electric Power Generating Industry
CO_2 (million tons/year)	-13	1,650
NO_X (thousand tons/year)	-8.7	1,020
SO_2 (thousand tons/year)	-13	954

Sources: U.S. EPA, 2024u; ERG, 2024g.

7.3 Solid Waste Generation

Solid waste associated with the implementation of the rule is based on the generation of residual treatment solids from the change in solids from membrane filtration versus LRTR, RO systems, and CP. The EPA estimated the amount of solid waste generated from each technology for each applicable plant.

- The EPA determined the FGD solids generated from membrane filtration with brine encapsulation by multiplying an aggregate solids value by the plant-specific optimized FGD flow rate (expressed in GPD). The EPA then subtracted out the backwash dry solids generated from an LRTR system. The EPA estimated FGD solids generated from SDE by multiplying an aggregate solids value by the plant-specific optimized FGD flow rate (expressed in gallons per day [GPD]). The EPA then subtracted out the backwash dry solids generated from an LRTR system.
- The EPA determined the BA solids (expressed in tons of brine solids per year) generated from RO systems by multiplying the purge flow (10 percent of the total BA system volume) by the average TDS concentration in BA transport water.[42]
- The EPA determined the CRL solids generated from CP treatment by multiplying a flow-normalized dewatered sludge generation rate (expressed in tons per day of sludge per gallon per minute CRL flow) by the plant's CRL flow rate. The EPA estimated CRL solids generated from membrane filtration and from SDE by multiplying an aggregate solids value by the plant-specific CRL flow rate (expressed in GPD).
- The EPA determined the legacy wastewater solids generated from CP treatment by multiplying a flow-normalized dewatered sludge generation rate (expressed in tons per day of sludge per gallon per minute legacy wastewater flow) by the plant's legacy wastewater flow rate.

The net change in national solid waste production associated with the regulatory options is shown in Table 31. The EPA estimated that solid waste generation associated with the treatment of discharges of unmanaged CRL could amount to as much as 4.2 million tons per year.

Table 31. Net Change in Industry-Level Solid Waste by Regulatory Option

Non-Water Quality Impact	Solid Waste Generation with the ELG		
	Option A	Option B	Option C
Solids (million tons/year)	1.33	1.74	2.23

Source: U.S. EPA, 2024u

[42] Similar to the 2020 rule methodology, the EPA assumed plants would transfer RO brine off site at an average distance of 40 miles.

7.4 Change in Water Use

Steam electric power plants generally use water for handling solid waste, including BA, and for operating wet FGD scrubbers. The EPA estimated the plant-specific change in water intake, or process water use, associated with FGD wastewater treatment and BA handling for each evaluated technology options and baseline.

Plants expected to install a membrane filtration system for FGD wastewater treatment under the regulatory options are expected to experience a decrease in water use compared to baseline because the EPA anticipates they will reuse the membrane permeate in the FGD scrubber. The EPA estimated the reduction in water use resulting from membrane filtration treatment compared to baseline is 70 percent of the optimized FGD flow.

The EPA estimates that the regulatory options evaluated will decrease water intake associated with BA handling as the regulatory options require zero discharge of the BA purge. The EPA used the purge volume for each plant, equivalent to 10 percent of the total remote MDS volume as defined in Section 5.2.1, to estimate the decrease in water intake for each plant for BA. The EPA does not expect the treatment technologies evaluated for the 2024 final rule have an impact on water use related to CRL or legacy wastewater treatment.

Table 32 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 equivalent to the change in wastewater discharge. The industry-level process water use for membrane filtration is the same for all brine management options considered.

Table 32. Net Change in Industry-Level Process Water Use by Regulatory Option

Non-Water-Quality Impact	Change in Water Use with the Option		
	Option A	Option B	Option C
Water reduction (MGD)	5.52	5.52	5.80

Source: U.S. EPA, 2024u

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