United States
Environmental Protection
Agency

Office of Water
Washington, DC 20460

EPA-821-R-13-002
April 2013

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

United States
Environmental Protection
Agency

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

EPA-821-R-13-002

April 2013

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

Questions regarding this document should be directed to:

U.S. EPA Engineering and Analysis Division (4303T)
1200 Pennsylvania Avenue NW
Washington, DC 20460
(202) 566-1000

TABLE OF CONTENTS

Page

TABLE OF CONTENTS *(Continued)*

Page

TABLE OF CONTENTS *(Continued)*

TABLE OF CONTENTS *(Continued)*

Page

TABLE OF CONTENTS *(Continued)*

Page

TABLE OF CONTENTS *(Continued)*

TABLE OF CONTENTS *(Continued)*

Page

List of Tables

Page

List of Tables (*Continued*)

Page

List of Tables (*Continued*)

Page

List of Tables (*Continued*)

Page

List of Tables (*Continued*)

Page

List of Figures

Page

List of Figures (*Continued*)

Page

SECTION 1
BACKGROUND

This section provides background information on the development of revised effluent limitations guidelines and standards (ELGs) proposed for the Steam Electric Power Generating Point Source Category (Steam Electric Category). Sections 1.1 and 1.2 discuss the legal authority and regulatory background for the proposed rule. Section 1.3 presents a history of Steam Electric Category rulemaking activities.

In addition to this report, the proposed Steam Electric ELGs are supported by a number of reports including:

- Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. 821-R-13-003. This report summarizes the environmental and human health improvements that result from implementation of the proposed ELGs.
- Benefits and Cost Analysis for the Proposed Steam Electric Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. EPA-821-R-13-004. This report summarizes the monetary benefits and societal costs that result from implementation of the proposed ELGs.
- Regulatory Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA), Document No. EPA-821-R-13-005. This report presents a profile of the steam electric industry, a summary of the costs and impacts associated with the regulatory options, and an assessment of the proposed ELGs impact on employment and small businesses.

The proposed effluent limitation guidelines and standards for the Steam Electric Power Generating Point Source Category are based on data generated or obtained in accordance with EPA’s Quality Policy and Information Quality Guidelines. EPA’s quality assurance (QA) and quality control (QC) activities for this rulemaking include the development, approval and implementation of Quality Assurance Project Plans for the use of environmental data generated or collected from sampling and analyses, existing databases and literature searches, and for the development of any models, which used environmental data.

1.1 LEGAL AUTHORITY

EPA is proposing revisions of the ELGs for the Steam Electric Category (40 Code of Federal Regulations (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.

1.2 CLEAN WATER ACT

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.” 33 U.S.C. 1251(a). The CWA establishes a comprehensive program for protecting our nation's waters. Among its core provisions, the CWA prohibits the discharge of pollutants from a point source to waters of the U.S. except as authorized under the CWA. Under section 402 of the CWA, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA also authorizes EPA to establish national technology-based effluent limitations guidelines and standards (ELGs) for discharges from categories of point sources.

The CWA authorizes EPA to promulgate nationally applicable pretreatment standards that restrict pollutant discharges from facilities that discharge wastewater indirectly through sewers flowing to publicly owned treatment works (POTWs), as outlined in section 307(b) and (c), 33 U.S.C. 1317(b) and (c). EPA establishes national pretreatment standards for those pollutants in wastewater from indirect dischargers that may pass through, interfere with, or are otherwise incompatible with POTW operations. Generally, pretreatment standards are designed to ensure that wastewaters from direct and indirect industrial dischargers are subject to similar levels of treatment. See CWA section 301(b), 33 U.S.C. 1311(b). In addition, POTWs are required to implement local treatment limits applicable to their industrial indirect dischargers to satisfy any local requirements. See 40 CFR 403.5.

Direct dischargers (i.e., those discharging directly to surface waters) must comply with effluent limitations in NPDES permits. Indirect dischargers, who discharge through POTWs, must comply with pretreatment standards. Technology-based effluent limitations in NPDES permits are derived from effluent limitations guidelines (CWA sections 301 and 304, 33 U.S.C. 1311 and 1314) and new source performance standards (CWA section 306, 33 U.S.C. 1316) promulgated by EPA, or based on best professional judgment (BPJ) where EPA has not promulgated an applicable effluent guideline or new source performance standard (CWA section 402(a)(1)(B), 33 U.S.C. 1342(a)(1)(B)). Additional limitations based on water quality standards are also required to be included in the permit in certain circumstances. CWA section 301(b)(1)(C), 33 U.S.C. 1311(b)(1)(C). The ELGs are established by regulation for categories of industrial dischargers and are based on the degree of control that can be achieved using various levels of pollution control technology.

EPA promulgates national ELGs for major industrial categories for three classes of pollutants: (1) conventional pollutants (i.e., total suspended solids (TSS), oil and grease (O&G), biochemical oxygen demand (BOD_5), fecal coliform, and pH), as outlined in CWA section 304(a)(4) and 40 CFR 401.16; (2) toxic pollutants (e.g., toxic metals such as arsenic, mercury, selenium, and chromium; toxic organic pollutants such as benzene, benzo-a-pyrene, phenol, and naphthalene), as outlined in section 307(a) of the Act, 40 CFR 401.15 and 40 CFR part 423 appendix A; and (3) non-conventional pollutants, which are those pollutants that are not categorized as conventional or toxic (e.g., ammonia-N, phosphorus, and total dissolved solids).

EPA bases ELGs on the performance of control and treatment technologies. The legislative history of CWA section 304(b), which is the heart of the effluent guidelines program, describes the need to press toward higher levels of control through research and development of new processes, modifications, replacement of obsolete plans and processes, and other improvements in technology, taking into account the cost of controls. Congress has also stated that EPA need not consider water quality impacts on individual water bodies as the guidelines are developed; see Statement of Senator Muskie (October 4, 1972), reprinted in Legislative

History of the Water Pollution Control Act Amendments of 1972, at 170. (U.S. Senate, Committee on Public Works, Serial No. 93–1, January 1973.)

There are four types of standards applicable to direct dischargers (plants that discharge to surface waters), and two standards applicable to indirect dischargers (plants that discharge to POTWs). The following sections summarize these guidelines and standards.

1.2.1 Best Practicable Control Technology Currently Available (BPT)

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

1.2.2 Best Conventional Pollutant Control Technology (BCT)

The 1977 amendments to the CWA required EPA to identify additional levels of effluent reduction for conventional pollutants associated with BCT technology for discharges from existing industrial point sources. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that EPA establish BCT limitations after consideration of a two-part "cost reasonableness" test. EPA explained its methodology for the development of BCT limitations in July 9, 1986 (51 FR 24974). Section 304(a)(4) designates the following as conventional pollutants: BOD_5, TSS, fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated O&G as an additional conventional pollutant on July 30, 1979 (44 FR 44501; 40 CFR 401.16).

1.2.3 Best Available Technology Economically Achievable (BAT)

BAT represents the second level of stringency for controlling direct discharge of toxic and nonconventional pollutants. In general, BAT ELGs represent the best available economically achievable performance of facilities in the industrial subcategory or category. As the statutory phrase intends, EPA considers the technological availability and the economic achievability in determining what level of control represents BAT. CWA section 301(b)(2)(A), 33 U.S.C. 1311(b)(2)(A). Other statutory factors that EPA considers in assessing BAT are the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, and non-water quality environmental impacts, including energy requirements and such other factors as the Administrator deems appropriate. CWA section 304(b)(2)(B), 33 U.S.C. 1314(b)(2)(B). The Agency retains considerable discretion in assigning the weight to be accorded these factors. *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1045 (D.C. Cir. 1978). Generally, EPA determines economic achievability based on the effect of the cost of compliance with BAT limitations on overall industry and subcategory financial conditions. BAT may reflect the highest performance in the industry and may reflect a higher level of performance than is currently being achieved based on technology transferred from a different subcategory or category, bench scale or pilot plant studies, or foreign plants. *American Paper Inst. v. Train*, 543 F.2d 328, 353 (D.C. Cir. 1976); *American Frozen Food Inst. v Train*, 539 F.2d 107, 132 (D.C. Cir. 1976). BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice. *See American Frozen Foods*, 539 F.2d at 132, 140; *Reynolds Metals Co. v. EPA*, 760 F.2d 549, 562 (4th Cir. 1985); *California & Hawaiian Sugar Co. v. EPA*, 553 F.2d 280, 285-88 (2nd Cir. 1977).

1.2.4 New Source Performance Standards (NSPS)

NSPS reflect effluent reductions that are achievable based on the best available demonstrated control technology (BADCT). Owners of new facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS should represent the most stringent controls attainable through the application of the BADCT for all pollutants (that is, conventional, non-conventional, and toxic pollutants). In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements. CWA section 306(b)(1)(B), 33 U.S.C. 1316(b)(1)(B).

1.2.5 Pretreatment Standards for Existing Sources (PSES)

Section 307(b), 33 U.S.C. 1317(b), of the Act calls for EPA to issue pretreatment standards for discharges of pollutants to POTWs. PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT. The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR part 403. These regulations establish pretreatment standards that apply to all non-domestic dischargers. See 52 FR 1586 (January 14, 1987).

1.2.6 Pretreatment Standards for New Sources (PSNS)

Section 307(c), 33 U.S.C. 1317(c) of the Act calls for EPA to promulgate PSNS. Such pretreatment standards must prevent the discharge of any pollutant into a POTW that may interfere with, pass through, or may otherwise be incompatible with the POTW. EPA promulgates PSNS based on best available demonstrated control technology (BADCT) for new sources. New indirect dischargers have the opportunity to incorporate into their facilities the best available demonstrated technologies. The Agency typically considers the same factors in promulgating PSNS as it considers in promulgating NSPS.

1.3 REGULATORY HISTORY OF THE STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

This section presents a brief history of Steam Electric Category rulemaking activities. Section 1.3.1 discusses the existing steam electric industry wastewater discharge regulations. Section 1.3.2 discusses the Detailed Study of the Steam Electric Category. Section 1.3.3 discusses other statutes and regulatory requirements affecting this industry.

1.3.1 Summary of Current ELGs Discharge Requirements and Applicability

The CWA establishes a structure for regulating discharges of pollutants to surface waters of the United States. As part of the implementation of the CWA, EPA issues ELGs for industrial dischargers. EPA first issued ELGs for the Steam Electric Category in 1974 with subsequent revisions in 1977 and 1982. The Steam Electric ELGs are codified at 40 CFR 423 and include limitations for the following wastestreams:

- Once-through cooling water;
- Cooling tower blowdown;
- Fly ash transport water;
- Bottom ash transport water;
- Metal cleaning wastes;
- Coal pile runoff; and
- Low-volume waste sources, including but not limited to, wastewaters from wet scrubber air pollution control systems, ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, and recirculating house service water systems (sanitary and air conditioning wastes are not included) [40 CFR 423.11(b)].

Table 1-1 summarizes the current ELGs, which are applicable to:

> "…discharges resulting from the operation of a generating unit by an establishment primarily engaged in the generation of electricity for distribution and sale which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium." [40 CFR 423.10]

The ELGs do not apply to discharges from generating units that primarily use a nonfossil or nonnuclear fuel source (e.g., wood waste, municipal solid waste) to power the steam electric generators, nor do they apply to generating units operated by establishments that are not primarily engaged in generating electricity for distribution and sale.

Table 1-1. Current Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category

Wastestream	BPT[a]	BAT[a]	NSPS[a]	PSES and PSNS[a]
All Wastestreams	pH: 6-9 S.U. [b] PCBs: Zero discharge	PCBs: Zero discharge	pH: 6-9 S.U. [b] PCBs: Zero discharge	PCBs: Zero discharge
Fly Ash Transport	TSS: 100 mg/L; 30 mg/L Oil & Grease: 20 mg/L; 15 mg/L		Zero discharge	Zero discharge (PSNS only) No limitation for PSES
Bottom Ash Transport	TSS: 100 mg/L; 30 mg/L Oil & Grease: 20 mg/L; 15 mg/L		TSS: 100 mg/L; 30 mg/L Oil & Grease: 20 mg/L; 15 mg/L	
Low Volume Wastes	TSS: 100 mg/L; 30 mg/L Oil & Grease: 20 mg/L; 15 mg/L		TSS: 100 mg/L; 30 mg/L Oil & Grease: 20 mg/L; 15 mg/L	
Once-Through Cooling	Free Available Chlorine: 0.5 mg/L; 0.2 mg/L	Total Residual Chlorine: For any plant with rated electric generating capacity ≥ 25 MW: 0.20 mg/L instantaneous maximum; For any plant with rated electric generating capacity < 25 MW, equal to BPT	Total Residual Chlorine: For any plant with rated electric generating capacity ≥ 25 MW: 0.20 mg/L instantaneous maximum; For any plant with rated electric generating capacity < 25 MW, equal to BPT	
Cooling Tower Blowdown	Free Available Chlorine: 0.5 mg/L; 0.2 mg/L	Free Available Chlorine: 0.5 mg/L; 0.2 mg/L 126 Priority Pollutants: No detectable amount, except: Chromium, total: 0.2 mg/L; 0.2 mg/L Zinc, total: 1.0 mg/L; 1.0 mg/L	Free Available Chlorine: 0.5 mg/L; /0.2 mg/L 126 Priority Pollutants: No detectable amount, except: Chromium, total: 0.2 mg/L; 0.2 mg/L Zinc, total: 1.0 mg/L; 1.0 mg/L	126 Priority Pollutants: Zero discharge, except: Chromium: 0.2 mg/L; 0.2 mg/L Zinc: 1.0 mg/L; 1.0 mg/L
Coal Pile Runoff	TSS*: 50 mg/L instantaneous maximum		TSS*: 50 mg/L instantaneous maximum	

Table 1-1. Current Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category

Wastestream	BPT[a]	BAT[a]	NSPS[a]	PSES and PSNS[a]
Chemical Metal Cleaning Wastes	TSS: 100 mg/L; 30 mg/L Oil & Grease: 20 mg/L; 15 mg/L Copper: 1.0 mg/L; 1.0 mg/L Iron: 1.0 mg/L; 1.0 mg/L	Copper: 1.0 mg/L; 1.0 mg/L Iron: 1.0 mg/L; 1.0 mg/L	TSS: 100 mg/L; 30 mg/L Oil & Grease: 20 mg/L; 15 mg/L Copper: 1.0 mg/L; 1.0 mg/L Iron: 1.0 mg/L; 1.0 mg/L	Copper: 1.0 mg/L (daily maximum)
Non-chemical Metal Cleaning Wastes		Reserved	Reserved	Reserved

Source: [40 CFR Part 423].

a -The limitations for TSS, oil & grease, copper, iron, chromium, and zinc are presented in the table as daily maximum (mg/L); 30-day average (mg/L). For all effluent guidelines, where two or more wastestreams are combined, the total pollutant discharge quantity may not exceed the sum of allowable pollutant quantities for each individual wastestream. BPT, BAT, and NSPS allow either mass- or concentration-based limitations.

b -The pH limitation is not applicable to once-through cooling water.

Free Available Chlorine: 0.5 mg/L; 0.2 mg/L - 0.5 mg/L instantaneous maximum, 0.2 mg/L average during chlorine release period. Discharge is limited to 2 hrs/day/unit. Simultaneous discharge of chlorine from multiple units is prohibited. Limitations are applicable at the discharge from an individual unit prior to combination with the discharge from another unit.

Total Residual Chlorine: 0.20 mg/L instantaneous maximum. Total residual chlorine (TRC) = free available chlorine (FAC) + combined residual chlorine (CRC). TRC discharge is limited to 2 hrs/day/unit. TRC is applicable to plants ≥25 MW, and FAC is applicable to plants <25 MW. The TRC limitation is applicable at the discharge point to surface waters of the United States and may be subsequent to combination with the discharge from another unit.

126 Priority Pollutants: zero discharge - 126 priority pollutants from added maintenance chemicals (refer to App. A to 40 CFR 423). At the permitting authority's discretion, compliance with the zero-discharge limitations for the 126 priority pollutants may be determined by engineering calculations, which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

TSS*: 50 mg/L instantaneous maximum on coal pile runoff streams. No limitation on TSS for coal pile runoff flows ≥10-year, 24-hour rainfall event.

1.3.2 Detailed Study of the Steam Electric Power Generating Point Source Category

Section 304 of the CWA requires EPA to periodically review all effluent limitations guidelines and standards to determine whether revisions are warranted. In addition, Section 304(m) of the CWA requires EPA to develop and publish, biennially, a plan that establishes a schedule for the review and revision of promulgated national effluent guidelines required by Section 304(b) of the CWA. During the 2005 annual review of the existing effluent guidelines for all categories, EPA identified the regulations governing the steam electric power generating point source category for possible revision. At that time, publicly available data reported through the NPDES permit program and the Toxics Release Inventory (TRI) indicated that the industry ranked high in discharges of toxic and nonconventional pollutants. Because of these findings, EPA initiated a more detailed study of the category to determine if the effluent guidelines should be revised.

During the detailed study, EPA collected information on wastewater characteristics and treatment technologies through site visits, wastewater sampling, a data request that was sent to a limited number of companies, and various secondary data sources (Section 3 summarizes these data collection activities). EPA focused these data collection activities on certain discharges from coal-fired steam electric power plants (referred to in this report as “coal-fired power plants"). Based on the data collected, EPA determined that most of the toxic loadings for this category are associated with metals and certain other constituents, such as selenium, present in wastewater discharges, and that the wastestreams contributing the majority of these pollutants are associated with ash handling and wet flue gas desulfurization (FGD) systems. EPA also identified several wastestreams that are relatively new to the industry (e.g., carbon capture wastewater), and wastestreams for which there is little characterization data (e.g., gasification wastewater). See Section 4 and Section 7 for more information on these practices.

During the study, EPA found that the use of wet FGD systems to control sulfur dioxide (SO_2) emissions has increased significantly since the last revision of the effluent guidelines in 1982 and it is projected to continue increasing in the next decade as power plants take steps to address federal and state air pollution control requirements. EPA also found that FGD wastewaters generally contain significant levels of metals and other pollutants and that advanced treatment technologies are available to treat the FGD wastewater; however, most plants were employing surface impoundments designed primarily to remove suspended solids from FGD wastewater.

EPA also determined that technologies are available for handling the fly ash and bottom ash generated at a plant without using any water or at least eliminating the discharge of any transport water. EPA found that the fly ash and bottom ash transport waters generated from wet systems at coal-fired power plants are created in large quantities and contain significant concentrations of metals, including arsenic and mercury. Additionally, EPA determined that some of the metals are present primarily in the dissolved phase, and generally are not removed in the surface impoundments that are used to treat these wastestreams. Based on these findings, EPA determined that there are technologies readily available to reduce or eliminate the discharge of pollutants contained in fly ash and bottom ash transport water.

Finally, EPA determined that FGD and ash transport wastewaters contain pollutants that can have detrimental impacts to the environment. EPA reviewed publicly available data and found documented environmental impacts that were attributable to discharges from surface impoundments or discharges from leachate generated from landfills containing coal combustion residues. EPA determined that there are a number of pollutants present in wastewaters generated at coal-fired power plants that can impact the environment, including metals (e.g., arsenic, selenium, mercury), total dissolved solids (TDS), and nutrients. EPA found the interaction of coal combustion wastewaters with the environment has caused a wide range of harm to aquatic life.

Overall from the detailed study, EPA found that the industry is generating new wastestreams that during the previous rulemakings either were not evaluated or were evaluated to only a limited extent due to insufficient characterization data. Such wastestreams include FGD wastewater, flue gas mercury control (FGMC) wastewater, carbon capture wastewater, and gasification wastewaters. EPA also found that these wastestreams, as well as other combustion-related wastestreams at power plants (e.g., fly ash and bottom ash transport water, leachate) contain pollutants in concentrations and mass loadings that are causing documented environmental impacts and that treatment technologies are available to reduce or eliminate the pollutant discharges.

Upon completing the detailed study in 2009, EPA determined that the current regulations have not kept pace with the significant changes that have occurred in this industry over the last three decades. EPA's analysis of the wastewater discharges associated with steam electric power generation led the Agency to announce, in September 2009, plans to revise the effluent guidelines.

1.3.3 Other Statutes and Regulatory Requirements Affecting Management of Steam Electric Power Generating Wastewaters

EPA is taking action to reduce emissions, discharges, and other environmental impacts associated with steam electric power plants. These actions, which are being implemented by several different EPA offices (i.e., Office of Air and Radiation (OAR), Office of Solid Waste and Emergency Response (OSWER), Office of Water (OW)), include establishing new regulatory requirements which may affect the generation and composition of wastewater discharged from steam electric power plants. This section provides a brief overview of these statutes and regulatory requirements.

1. Mercury and Air Toxics Standards (MATS)

   When the CAA was amended in 1990, EPA was directed to control mercury and other hazardous air pollutants from major sources of emissions to the air. For power plants using fossil fuels, the amendments required EPA to conduct a study of hazardous air pollutant emissions. CAA Section 112(n)(1)(A). The CAA amendments also required EPA to consider the study and other information and to make a finding as to whether regulation was appropriate and necessary. In 2000, the Administrator found that regulation of hazardous air pollutants, including mercury, from coal- and oil-fired power plants was appropriate and necessary. 65 FR 79825 (Dec. 20, 2000).

EPA published the final MATS rule on February 16, 2012. 77 FR 9304. The rule established standards that will reduce emissions of hazardous air pollutants including metals (e.g., mercury, arsenic, chromium, nickel) and acid gases (e.g., hydrochloric acid, hydrofluoric acid). Steam electric power plants may use any number of practices, technologies, and strategies to meet the new emission limits, including using wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and fabric filters.

2. Cross-State Air Pollution Rule (CSAPR)

   EPA promulgated the CSAPR in 2011 to require 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions of SO_2, nitrogen oxides (NO_x) and/or ozone-season NO_x that cross state lines and significantly contribute to ground-level ozone and/or fine particle pollution problems in other states. The emissions of SO_2, NO_x and ozone-season NO_x addressed by the CSAPR react in the atmosphere to form PM2.5 and ground-level ozone and are transported long distances, making it difficult for a number of states to meet the national clean air standards that Congress directed EPA to establish to protect public health. The U.S. Court of Appeals for the D.C. Circuit stayed the CSAPR on December 30, 2011, and on August 21, 2012, issued an opinion vacating the rule and ordering EPA to continue administering the Clean Air Interstate Rule. *EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7 (D.C.Cir. 2012). On March 29, 2013, the United States filed a petition asking the Supreme Court to review the D.C. Circuit decision.

3. Greenhouse Gas Emissions for New Electric Utility Generating Units

   On April 13, 2012, the EPA proposed new source standards of performance under CAA section 111 for emissions of carbon dioxide (CO_2) for fossil-fuel-fired electricity generating units. 77 FR 22392. The proposed requirements, which apply only to new sources, would require new plants greater than 25 megawatts (MW) to meet an output-based standard of 1,000 pounds of CO_2 per MW-hour of electricity generated. EPA based this proposed standard on the performance of natural gas combined cycle technology because EPA and others project that even without this rule, for the foreseeable future, new fossil-fuel-fired power plants will be built with that technology. New coal- or petroleum coke-fired generating units could meet the standard by using carbon capture and storage of approximately 50 percent of the CO_2 in the exhaust gas when the unit begins operating or by later installing more effective carbon capture and storage to meet the standard on average over a 30-year period. EPA is evaluating the public comments received on the proposal and has not determined a schedule at this time for taking final action on the proposed rule.

4. Cooling Water Intake Structures (CWA Section 316(b))

   Section 316(b) of the CWA, 33 U.S.C. 1326(b), requires that standards applicable to point sources under section 301 and 306 of the Act require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to minimize adverse environmental impacts. Each year, these facilities withdraw large volumes of water from lakes, rivers, estuaries or oceans for use in their facilities. In the process, these facilities remove billions of aquatic organisms from waters of the United States each year, including fish, fish larvae and eggs, crustaceans, shellfish, sea turtles, marine mammals, and other aquatic life. The most significant effects of these withdrawals are on early life stages of fish and shellfish through impingement (being pinned against intake screens or other parts at the facility) and entrainment (being drawn into cooling water systems).

In November 2001, EPA took final action on regulations for cooling water intake structures at new facilities that have a design intake flow greater than 2 million gallons per day (MGD) and that have at least one cooling water structure that uses at least 25 percent of the water it withdraws for cooling purposes. See 40 CFR 125.81. EPA's requirements provide a two-track approach. Under Track 1, the intake flow at facilities that withdraw greater than 10 MGD is restricted to a level commensurate with the level that may be achieved by use of a closed-cycle recirculating cooling system. Facilities withdrawing greater than 10 MGD located in areas where fisheries need additional protection must also use technology or operational measures to further minimize impingement mortality and entrainment. For facilities with intakes of less than 10 MGD, the cooling water intake structures may not exceed a fixed intake screen velocity and the quantity of intake is restricted. Under Track 2, a facility may choose to demonstrate to the permitting authority that other technologies will reduce the level of adverse environmental impacts to a level that would be achieved under Track 1.

In March 2011, EPA proposed standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The proposed rule would subject existing power plants and manufacturing facilities withdrawing in excess of 2 MGD of cooling water to an upper limit on the number of fish destroyed through impingement, as well as site-specific entrainment mortality standards. Certain plants that withdraw very large volumes of water would also be required to conduct studies for use by the permit writer in determining site-specific entrainment controls for such facilities. Finally, under the proposed rule, new generating units at existing power plants would be required to reduce the intake of cooling water associated with the new unit, to a level which could be attained by using a closed-cycle cooling system. EPA is continuing analysis and is in the process of addressing comments and finalizing the rule.

5. Coal Combustion Residuals (CCR) Proposed Rule

CCRs are residues from the combustion of coal in steam electric power plants and include materials such as coal ash (fly ash and bottom ash) and FGD wastes. CCRs are currently exempt from the requirements of subtitle C of the Resource Conservation and Recovery Act (RCRA), which governs the disposition and management of hazardous wastes. Potential environmental concerns regarding the management and disposal of CCR include pollution leaching from surface impoundments and landfills contaminating ground water and natural resource damages and risks to human health caused by structural failures of surface impoundments, like that which occurred at the Tennessee Valley Authority's plant in Kingston, Tennessee, in December 2008. The spill, which flooded more than 300 acres of land with CCR and contaminated the Emory and Clinch rivers, emphasized the need for national standards to address risks associated with the disposal of CCR.

On June 21, 2010, EPA co-proposed regulations that included two approaches to regulating the disposal of CCRs generated by electric utilities and independent power producers. Under one proposed approach, EPA would list these residuals as "special wastes," when destined for disposal in landfills or surface impoundments, and would apply the existing regulatory requirements established under subtitle C of RCRA to such wastes. Under the second proposed approach, EPA would establish new regulations applicable specifically to CCRs under subtitle D of RCRA, the section of the statute applicable to solid (i.e., non-hazardous) wastes. Under both approaches, CCR that are beneficially used would remain exempt under the Bevill exclusion. EPA has not yet taken final action on the proposed CCR regulations.

SECTION 2
SUMMARY OF PROPOSED REGULATION

This section presents a brief summary of the proposed revisions to the ELGs. Section 2.1 summarizes the proposed revisions to discharge requirements and Section 2.2 describes the proposed revisions to the applicability provision and specialized definitions.

2.1 SUMMARY OF PROPOSED REVISIONS TO DISCHARGE REQUIREMENTS

The proposed Steam Electric rule would revise the technology-based ELGs at 40 CFR 423 for certain wastewater discharges associated with the operation of new and existing generating units within the Steam Electric Category. The current regulations, which were last updated in 1982, do not adequately address the toxic pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades. The development of new technologies for generating electric power (e.g., coal gasification) and the widespread implementation of air pollution controls (e.g., flue gas desulfurization (FGD), selective catalytic reduction (SCR)) have altered existing or created new wastewater streams at many power plants. Therefore, EPA is proposing to establish new or additional requirements for wastewaters associated with these new or altered wastestreams.

EPA is proposing to establish new requirements for BAT, NSPS, PSES, and PSNS for certain wastestreams, described below, for the Steam Electric ELGs. EPA is not proposing new BCT nor new BPT requirements as part of this proposed rulemaking. Section 8 describes the technology options considered for each wastestream as the basis for the regulations, as well as the combination of technology options/wastestreams that comprise the regulatory options considered for the rulemaking. As described in Section 8, EPA is considering several options in this rulemaking and has identified four preferred alternatives (i.e., Regulatory Options 3a, 3b, 3, and 4a) for regulation of existing discharges (i.e., BAT and PSES requirements) for the proposed revisions to the ELGs. EPA is also proposing Regulatory Option 4 for the new NSPS and PSNS requirements. The preferred alternatives for the proposed ELGs are summarized below.

<u>Discharges Directly to Surface Water from Existing Facilities</u>

For existing sources that discharge directly to surface water, with the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), under one preferred alternative for BAT (referred to as Option 3a) the proposed rule would establish BAT for wastestreams from these sources that include:

- "Zero discharge" effluent limit for all pollutants in fly ash transport water and wastewater from flue gas mercury control systems;
- Numeric effluent limits for mercury, arsenic, selenium and TDS in discharges of wastewater from gasification processes;

- Numeric effluent limits for copper and iron in discharges of nonchemical metal cleaning wastes;[1] and
- Effluent limits for bottom ash transport water and combustion residual leachate from landfills and surface impoundments that are equal to the current Best Practicable Control Technology Currently Available (BPT) effluent limits for these discharges (i.e., numeric effluent limits for TSS and oil and grease.

Under a second preferred alternative for BAT (referred to as Option 3b), the proposed rule would establish numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater from certain steam electric facilities (those with a total plant-level wet scrubbed capacity of 2,000 MW or greater).[2] All other proposed Option 3b requirements are identical to the proposed Option 3a requirements described above.

Under a third preferred alternative for BAT (referred to as Option 3), the proposed rule would establish numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater, with the exception of small generating units (i.e., 50 MW or smaller). All other proposed Option 3 requirements are identical to the proposed Option 3a requirements described above.

Under a fourth preferred alternative for BAT (referred to as Option 4a), the proposed rule would establish "zero discharge" effluent limits for all pollutants in bottom ash transport water, with the exception of all generating units with a nameplate capacity of 400 MW or less (for those generating units that are less than or equal to 400 MW, the proposed rule would set BAT equal to BPT for discharges of pollutants found in the bottom ash transport water). All other proposed Option 4a requirements are identical to the proposed Option 3 requirements described above.

In addition, for oil-fired generating units and small generating units (i.e., 50 MW or smaller) that are existing sources and discharge directly to surface waters, under the four preferred alternatives for regulation of existing sources, the proposed rule would establish effluent limits (BAT) equal to the current BPT effluent limits for the wastestreams listed above. [3]

Discharges to POTWs from Existing Facilities

For discharges from existing sources to POTWs, EPA is proposing to establish PSES that are equal to the proposed BAT, with the following exceptions:

[1] As described in Section VIII, EPA is proposing to exempt from new copper and iron BAT limitations any existing discharges of nonchemical metal cleaning wastes that are currently authorized without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits applicable to low volume wastes.

[2] Total plant-level wet scrubbed capacity is calculated by summing the nameplate capacity for all of the units that are serviced by wet FGD systems.

[3] As described in Section VIII, one of the preferred options would increase this threshold for purposes of discharges of pollutants in bottom ash transport water only, to 400 MW or less.

- Numeric standards for discharges of nonchemical metal cleaning wastes would be established only for copper;[4]
- Under Options 3a, 3b, and 3 for PSES, EPA is not proposing to establish pretreatment standards for discharges of bottom ash transport water. Under Option 4a, EPA is not proposing to establish pretreatment standards for discharges of bottom ash transport water for generating units with a nameplate capacity of 400 MW or less;[5] and
- Other than the pretreatment standards for nonchemical metal cleaning wastes, EPA is not proposing to establish pretreatment standards for existing sources for discharges from existing oil-fired units and small generating units (i.e., 50 MW or smaller).

Discharges Directly to Surface Water from New Sources

For all generating units that are new sources and discharge directly to surface waters, including oil-fired generating and small generating units, the proposed rule would establish NSPS that include:

- Numeric standards for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater;
- Maintaining the current “zero discharge” standard for all pollutants in fly ash transport water for direct dischargers;
- Establishing “zero discharge” standards for all pollutants in bottom ash transport water and wastewater from flue gas mercury control systems;
- Numeric standards for mercury, arsenic, selenium, and TDS in discharges of wastewater from gasification processes;
- Numeric standards for mercury and arsenic in discharges of combustion residual leachate; and
- Numeric standards for TSS, oil and grease, copper, and iron in discharges of nonchemical metal cleaning wastes.

Discharges to POTWs from New Sources

For generating units that are new sources and discharge to POTWs, including oil-fired generating units and small generating units, EPA is proposing to establish PSNS that are equal to the proposed NSPS, except that the PSNS would also establish a “zero discharge” standard for all pollutants in fly ash transport water (the current NSPS already includes a zero discharge standard for pollutants in fly ash transport water), and the PSNS would not include numeric standards for TSS, oil and grease, or iron in discharges of nonchemical metal cleaning wastes.

[4] As described in Section VIII, EPA is proposing to exempt from new copper PSES standards any existing discharges of nonchemical metal cleaning wastes that are currently authorized without copper limits. For these discharges, the regulations would not specify PSES.

[5] This is because, as explained in Section VII, EPA generally does not establish pretreatment standards for conventional pollutants (e.g., TSS and oil and grease) because POTWs are designed to treat these conventional pollutants.

EPA is also proposing to add provisions to the ELGs that would prevent facilities from circumventing the new effluent limitations guidelines and standards. The proposed provision would do the following:

- Generally require that compliance with the effluent limits applicable to a particular wastestream be demonstrated prior to mixing the treated wastestream with other wastestreams; and
- Establish requirements that prevent moving effluent produced by a process operation for which there is a zero discharge effluent limit/standard, to another process operation for discharge under less stringent requirements.

In addition to the proposed requirements, EPA is also considering establishing the following provisions to the ELGs:

- Establish best management practices (BMP) requirements that would apply to surface impoundments containing coal combustion residuals (e.g., ash ponds, FGD ponds); and
- Establish a voluntary program that would provide incentives for existing power plants that dewater and close their surface impoundments containing combustion residuals and for power plants that eliminate the discharge of all process wastewater (excluding cooling water discharges).

2.2 REVISIONS TO APPLICABILITY PROVISION AND SPECIALIZED DEFINITIONS

In addition to the proposed revisions to the discharge requirements, EPA is proposing certain modifications to the applicability provision for the ELGs. These are not substantive modifications that would alter which generating units are regulated by the ELGs. These units have been traditionally regulated by the exiting ELGs. Instead, the proposed modifications would remove potential ambiguity present in the current regulatory text. The changes include:

- Clarification that certain facilities, such as certain municipal-owned facilities, which generate and distribute electricity within a service area (such as distributing electric power to municipal-owned buildings), but which use accounting practices which are not commonly thought of as a "sale" are nevertheless subject to the ELGs;
- Clarification that "primarily," as used in 423.10, refers to those operations where the generation of electricity is the predominant source of revenue and/or principal reason for operation;
- Clarification that fuels derived from fossil fuel are within the scope of the current ELGs; and
- Clarification that combined cycle systems, which are generating units composed of one or more combustion turbines operating in conjunction with one or more steam turbines, are subject to the ELGs.

In addition to the proposed revisions discussed above, EPA is proposing revisions to certain existing specialized definitions, as well as inclusion of new specialized definitions. The proposed revisions to existing specialized definitions (with revisions underlined) are:

(b) The term *low volume waste sources* means, taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established in this part. Low volume waste sources include, but are not limited to, the following: wastewaters from ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, recirculating house service water systems, and scrubber air pollution control systems whose primary purpose is particulate removal. Sanitary wastes, air conditioning wastes, and wastewater from carbon capture or sequestration systems are not included in this definition.

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

The proposed new specialized definitions are:

(n) The term *flue gas desulfurization (FGD) wastewater* means any process wastewater generated specifically from the wet FGD scrubber system, including any solids separation or solids dewatering processes.

(o) The term *flue gas mercury control (FGMC) wastewater* means any process wastewater generated from an air pollution control system installed or operated for the purpose of removing mercury from flue gas. This includes fly ash collection systems when the particulate control system follows the injection of sorbents or implementation of other controls to remove mercury from flue gas. Flue gas desulfurization systems are not included in this definition.

(p) The term *transport water* means any process wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection equipment, or boiler, and has direct contact with the ash.

(q) The term *gasification wastewater* means, taken collectively as if from one source, wastewater from all sources associated with the gasification process or related chemical recovery processes at an integrated gasification combined cycle operation. Gasification wastewater includes, but is not limited to, slag handling wastewater, fly ash stream, sour/grey water (which consists of condensate from gas cooling, as well as other wastestreams), CO_2/steam stripper wastewater, air separation unit blowdown, and sulfur recovery unit blowdown.

(r) The term *combustion residual leachate* means leachate from onsite landfills or surface impoundments (e.g., ponds) containing combustion residuals. Leachate includes liquid, including any suspended or dissolved constituents in the liquid that has percolated through or drained from waste or other materials emplaced in a landfill, or that pass through the containment structure (e.g., bottom, dikes, berms) of a surface impoundment. Leachate also includes the terms seepage, drains, leak, and leakage, which are generally used in reference to leachate from an impoundment.

(s) The term *oil-fired unit* means a generating unit that uses oil as the primary or secondary fuel source and does not use a gasification process or any coal or petroleum coke as a fuel source. This definition does not include units that use oil only for start up or flame-stabilization purposes.

(t) The term *sufficiently sensitive analytical method* means a method that ensures the sample-specific quantitation level for the wastewater being analyzed is at or below the level of the effluent limitation.

(u) The term *nonchemical metal cleaning waste* means any wastewater resulting from the cleaning of any metal process equipment without chemical cleaning compounds, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.

SECTION 3
DATA COLLECTION ACTIVITIES

EPA collected and evaluated information and data from various sources in the course of developing the proposed effluent limitations guidelines and standards (ELGs) for the Steam Electric Power Generating Point Source Category (Steam Electric Category). EPA used these data to develop the industry profile, determine the applicability of the rule, evaluate industry subcategorization, and determine wastewater characteristics, technology options, compliance costs, pollutant loading reductions, and non-water quality environmental impacts. This section discusses the following data collection activities as they relate to technical aspects of this proposed rulemaking:

- Steam Electric Power Generating Detailed Study (Section 3.1);
- Engineering site visits (Section 3.2);
- Questionnaire for the Steam Electric Power Generating Effluent Guidelines (Section 3.3);
- Field sampling program (Section 3.4);
- EPA and state sources (Section 3.5);
- Industry-submitted data (Section 3.6);
- Technology vendor data (Section 3.7);
- Other data sources (Section 3.8); and
- Protection of confidential business information (Section 3.9).

3.1 STEAM ELECTRIC POWER GENERATING DETAILED STUDY

EPA conducted a detailed study of the steam electric power generating industry between 2005 and 2009. During the study, EPA collected data about the industry by performing the following activities:

- Conducted 34 site visits and six wastewater sampling episodes at steam electric power plants;
- Distributed a questionnaire to collect data from nine companies (operating 30 coal-fired power plants);
- Reviewed publicly available sources of data; and
- Coordinated with EPA program offices, other government organizations (e.g., state groups and permitting authorities), and industry and other stakeholders.

EPA's *Steam Electric Power Generating Point Source Category: Detailed Study Report* provides an overview of the steam electric power generating industry and its wastewater discharges, and the data collection activities and analyses conducted during EPA's detailed study [U.S. EPA, 2009b]. The study focused largely on discharges associated with coal ash handling operations and wastewater from flue gas desulfurization (FGD) air pollution control systems because these sources are responsible for the majority of the toxic pollutants currently discharged by steam electric power plants.

EPA also evaluated wastewater from coal pile runoff, condenser cooling, equipment cleaning, and leachate from landfills and surface impoundments. Additionally, EPA reviewed information on integrated gasification combined cycle (IGCC) operations and carbon capture technologies. EPA also identified wastewaters from flue gas mercury control systems and regeneration of the catalysts used for Selective Catalytic Reduction (SCR) NOx controls as potential new wastestreams that warrant attention.

EPA used the information collected during the detailed study to select plants with different technology bases for site visits, support the development of the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey), select plants to receive the questionnaire, and select plants for EPA's sampling program during the rulemaking. Additionally, EPA used the data collected during the detailed study to develop an industry profile and supplement the findings from the survey and sampling program (i.e., Form 2C data provided by the industry trade association). The remainder of Section 3 provides additional details regarding the data used from the study.

3.2 ENGINEERING SITE VISITS

EPA conducted a site visit program to gather information on the types of wastewaters generated by steam electric power plants, and the methods of managing these wastewaters to allow for recycle, reuse, or discharge. EPA focused data gathering activities primarily on FGD wastewater treatment and management of ash transport water at coal- and petroleum coke-fired power plants because the FGD and ash transport water streams are the primary sources of pollutant discharges from the industry. EPA also conducted site visits at oil-, gas-, and nuclear-fueled power plants to better understand the plant operations, the wastewaters generated, and the types of treatment systems used. EPA conducted 65 site visits at steam electric power plants in 22 states between December 2006 and February 2013. The Agency conducted three additional site visits in Italy in April 2011 to obtain information on their FGD wastewater treatment systems. Table 3-1 summarizes the site visits conducted. The list of site visits excludes EPA sampling episodes and EPA audits of CWA 308 sampling described in Section 3.4.

The purpose of the site visits was to collect information about each site's electric generating processes, wastewater management practices, and treatment technologies, and to evaluate each plant for potential inclusion in EPA's sampling program. To identify potential candidate plants for site visits, EPA used information from EPA's Office of Air and Radiation (OAR) and data provided by the Utility Water Act Group (UWAG), and other sources to determine the types of operations at power plants. During the detailed study, EPA used the UWAG data in conjunction with information from other sources, including publicly available plant-specific information, state and regional permitting authorities, and the Study data request, to identify plants to contact and obtain additional details regarding the plants' operations. During the rulemaking effort, EPA identified potential site visit candidates based on information provided in the survey (i.e., plant operating characteristics). From the information obtained during these contacts, EPA selected plants for site visits.

The specific objectives of these site visits were to:

- Gather general information about each plant's operations;
- Gather information on pollution prevention and wastewater treatment/operations;
- Evaluate whether the plant was appropriate to include in the sampling program;
- Gather plant-specific information to develop sampling plans; and
- Select and evaluate potential sampling points.

Table 3-1. List of Site Visits Conducted During the Detailed Study and Rulemaking

Plant Name, Location	Month/Year of Site Visit
Yates, *Georgia*	Dec 2006
Wansley, *Georgia*	Dec 2006
Widows Creek, *Alabama*	Dec 2006; Sept 2007
Conemaugh, *Pennsylvania*	Feb 2007; Aug 2012
Homer City, *Pennsylvania*	Feb 2007; Aug 2007; Aug 2012
Pleasant Prairie, *Wisconsin*	Apr 2007; Mar 2010
Bailly, *Indiana*	Apr 2007
Seminole, *Florida*	Apr 2007; Jan 2013
Big Bend, *Florida*	Apr 2007; Jul 2007
Cayuga, *New York*	May 2007
Mitchell, *West Virginia*	May 2007; Oct 2007
Cardinal, *Ohio*	May 2007; Oct 2007; Feb 2010
Bruce Mansfield, *Pennsylvania*	Oct 2007
Roxboro, *North Carolina*	Mar 2008
Belews Creek, *North Carolina*	Mar 2008; Oct 2008
Marshall, *North Carolina*	Mar 2008
Mount Storm, *West Virginia*	Sept 2008
Harrison, *West Virginia*	Sept 2008
Mountaineer, *West Virginia*	Sept 2008; Jan 2009
Gavin, *Ohio*	Sept 2008
Deely, *Texas*	Oct 2008
Clover, *Virginia*	Oct 2008
JK Spruce, *Texas*	Oct 2008
Fayette Power Project/Sam Seymour, *Texas*	Oct 2008
Ghent, *Kentucky*	Dec 2008
Trimble County, *Kentucky*	Dec 2008
Cane Run, *Kentucky*	Dec 2008
Mill Creek, *Kentucky*	Dec 2008
Brandon Shores, *Maryland*	Jan 2009; Mar 2010
Kenneth C Coleman, *Kentucky*	Feb 2009
Gibson, *Indiana*	Feb 2009

Table 3-1. List of Site Visits Conducted During the Detailed Study and Rulemaking

Plant Name, Location	Month/Year of Site Visit
Paradise, *Kentucky*	Feb 2009
Wabash River, *Indiana*	Feb 2009; Aug 2010
Miami Fort, *Ohio*	Apr 2009; Mar 2010
Covanta, *Virginia*	Jul 2009
Chesterfield, *Virginia*	Sept 2009
Karn-Weadock, *Michigan*	Sept 2009
Kinder Morgan Power, *Michigan*	Sept 2009
Monroe, *Michigan*	Sept 2009
Allen, *North Carolina*	Oct 2009
Cape Fear, *North Carolina*	Oct 2009
Catawba, *South Carolina*	Oct 2009
HB Robinson, *South Carolina*	Oct 2009
FP&L Sanford, *Florida*	Oct 2009
Polk, *Florida*	Oct 2009
Fort Martin, *West Virginia*	Feb 2010
Hatfield's Ferry, *Pennsylvania*	Feb 2010
Keystone, *Pennsylvania*	Feb 2010
Dickerson, *Maryland*	Mar 2010
Dallman, *Illinois*	Apr 2010
Duck Creek, *Illinois*	Apr 2010
Iatan, *Missouri*	Apr 2010
Edwardsport, *Indiana*	Mar 2011
Torrevaldaliga Nord, *Italy*	Apr 2011
Monfalcone, *Italy*	Apr 2011
Frederico II (Brindisi), *Italy*	Apr 2011
FP&L Manatee, *Florida*	Nov 2011
Wateree, *South Carolina*	Jan 2013
McMeekin, *South Carolina*	Jan 2013

3.3 QUESTIONNAIRE FOR THE STEAM ELECTRIC POWER GENERATING EFFLUENT GUIDELINES

The principal source of information and data used in developing the ELGs is the industry response to the survey distributed by EPA under the authority of Section 308 of the Clean Water Act (CWA), 33 U.S.C. 1318. EPA designed the industry survey to obtain technical information related to wastewater generation and treatment, and economic information such as costs of wastewater treatment technologies and financial characteristics of potentially affected companies. The responses were used to evaluate pollution control options for establishing revisions to the ELGs for the Steam Electric Category.

EPA developed an Information Collection Request (ICR) entitled *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey). The survey was approved by the Office of Management and Budget (OMB) in May 2010 (OMB Control No. 2040-0281).

The survey comprised the following nine parts:

- Part A: Steam Electric Power Plant Operations
- Part B: FGD Systems
- Part C: Ash Handling
- Part D: Pond/Impoundment Systems and Other Wastewater Treatment Operations
- Part E: Wastes from Cleaning Metal Process Equipment
- Part F: Management Practices for Ponds/Impoundments and Landfills
- Part G: Leachate Sampling Data for Ponds/Impoundments and Landfills
- Part H: Nuclear Power Generation
- Part I: Economic and Financial Data

Part A gathered information on all steam electric generating units at the surveyed plant, the fuels used to generate electricity, air pollution controls, cooling water, ponds/impoundments and landfills used for coal combustion residues (CCR), coal storage and processing, and outfalls. Parts B through I collected economic data and detailed technical information on certain aspects of power plant operations, including requiring some plants to collect and analyze wastewater samples.

In order to identify the population of plants that would be candidates to receive the survey, EPA first created a sample frame consisting of all fossil- and nuclear-fueled steam electric power plants in the United States that reported operating under NAICS code 22, and their corresponding generating units. NAICS code 22 (Utilities) comprises establishments engaged in providing the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Because power generation was not the primary purpose of some of the plants in this NAICS code (i.e., sewage removal plants), EPA removed them from the sample frame.

The resulting sample frame consisted of information obtained from databases that are maintained by the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE) that collects information on existing electric generating plants and associated equipment to evaluate the current status and potential trends in the industry. The source of the information came primarily from the 2007 Electric Generator Report (Form EIA-860) and was supplemented by information collected by Form EIA-923 and a survey conducted by EPA's Office of Solid Waste and Emergency Response (OSWER) [U.S. EPA, 2009a]. In addition, EPA identified two plants that started operations after 2007 and obtained information about them from Internet searches.

Collectively, the data sources provided key frame information for each steam electric power plant with a NAICS code of 22, such as county, state, North American Electric Reliability Council (NERC) region, business size (small or non-small), and regulatory status (e.g., regulated by public service commission). Also included in the data sources were the number of each type of generating unit operated at the plant, an identifier that specified the fuel classification of each generating unit for the plant, and an identifier based on the fuel classifications of the generating units (e.g., coal, gas-combined cycle, nuclear). In addition, the OSWER survey results and the EIA-923 data set provided information on the presence of surface impoundments and landfills at the plant along with the materials that were stored or disposed of in the impoundment/landfill. EPA also used data for each generating unit reported in the EIA-860 data set classified as a steam electric generating unit, such as prime mover and fuel (fossil or nuclear), nameplate capacity (in megawatts (MW)), unit fuel classification, and the plant where the generating unit is housed. The sample frame contained information on 1,197 plants containing 2,571 generating units that were potentially within the scope of the Steam Electric ELGs.

To minimize the burden on the respondents, EPA grouped plants into strata based on fuel classification so that an efficient stratified sampling scheme could be used.[6] This sampling strategy allowed for different sampling rates across the strata. Depending on the amount or type of information it required for the rulemaking, EPA solicited information either from all plants within a stratum (i.e., a census or “certainty” stratum) or from a random sample of plants within a stratum (i.e., probability sampled stratum). As a result, the survey was distributed to all coal- and petroleum coke-fired power plants and a sample of the rest of the steam electric industry, including oil-fired, gas-fired, gas-combined cycle, and nuclear power plants. Table 3-2 presents the number of plants in each fuel classification (i.e. strata) included in the sample frame used to identify survey recipients.

Table 3-2. Number of Plants in Each Fuel Classification in the Survey Sample Frame Used to Identify Survey Recipients

Fuel Classification	Number of Facilities
Coal	495
Petroleum coke	9
Oil	43
Gas	555
Nuclear	63
Combination[a]	32

a - EPA used the “combination” designation for plants that have at least two generating units that have different unit-level designations (e.g., oil, gas, nuclear), but do not have any coal or petroleum coke units.

The survey comprised several sections that were tailored to address specific processes, data needs, or types of power plants. Parts A and I of the survey were sent to all sampled plants;

[6] EPA classified plants into the fuel categories to develop the sample frame of all fossil- and nuclear-fueled steam electric power plants in the United States. EPA further developed plant-level fuel classifications based on a hierarchy of the type of units operating at the plant; therefore, some plants may operate units that burn other types of fuel in addition to the fuel under which they are classified. Plants that operated coal- or petroleum coke-fired units were classified as coal or petroleum coke regardless of other fuels at the plant. For example, a plant classified as coal will have coal-fired unit(s) at the plant, but may also have oil- fired, gas-fired, or nuclear unit(s).

the remaining sections were sent to sampled plants according to their fuel classification. Specifically, in addition to Parts A and I, all coal- and petroleum coke-fired power plants received Parts B, C, D, and H. A subsample of coal- and petroleum coke-fired power plants also received Parts E, F, and G. The sampled plants in the oil-fired and combination strata received Parts A, B, C, D, E, H, and I.[7] The sampled plants in the gas-fired, gas-combined cycle, and nuclear power strata received Parts A, E, H, and I.

Most parts of the survey focused on gathering information from all coal- and petroleum coke-fired power plants. Therefore, all plants with a fuel classification of coal or petroleum coke were selected with certainty (i.e., probability of selection equal to one), except for Parts E, F, and G. In addition, for strata with 10 or fewer plants, EPA included all plants in the sample, and at least 10 plants were sampled within strata containing more than 10 plants. As such, all regulated and nonregulated combination plants (except gas-fired and gas-combined cycle) were selected with certainty. For the remaining no regulated and regulated plants with plant fuel classifications of gas, gas-combined cycle, oil, nuclear, and combination (gas and gas-combined cycle), EPA randomly selected 30 percent of the plants to receive the survey while adhering to the 10 plant minimum per stratum. Based on this sampling design, 733 plants were selected to receive the survey. This total includes 495 coal-fired, 9 petroleum coke-fired, 20 oil-fired, 167 gas-fired, 20 nuclear power plants, and 22 combination power plants.

EPA received 733 completed surveys, including those from 53 plants that certified that they were not and did not have the capability to be engaged in steam electric power production, would be retired by December 31, 2011, or did not generate electricity in 2009 by burning any fossil or nuclear fuels.[8] Because responses were received for all 733 sampled plants (including those 53 plants that were not required to complete the remainder of the survey), there were no plants that were considered non-respondents, thus the response rate is 100 percent.

EPA then developed weighting factors to represent the entire industry on a national level from the data provided by the 733 plants that received the survey. Because coal- and petroleum coke-fired plants were selected with certainty, EPA did not weight the responses for the majority of data because all plants were represented. However, because EPA sent only Parts E, F, and G of the survey to a probability sample of coal- and petroleum coke-fired plants, the Parts E, F, and G data were weighted to represent the entire industry. In addition, data collected from the probability-sampled strata for other fuel types were weighted to represent the entire industry. All survey data presented in this document have been weighted to represent the entire industry, unless otherwise noted.

3.4 FIELD SAMPLING PROGRAM

Between July 2007 and April 2011, EPA conducted a sampling program at 17 different steam electric power plants in the United States and Italy to collect wastewater characterization

[7] For the purpose of the survey, combination power plants mean plants that do not operate generating units fueled by coal or petroleum coke and have at least two generating units that have different unit-level fuel classifications (e.g., gas and oil, gas and gas-combined cycle).

[8] At the time EPA developed the survey, EPA used 2011 as the cutoff year for retirements because the plants would be retired before the proposed rule was published.

data and/or treatment performance data associated with FGD wastewater, fly ash and bottom ash wastewater, and wastewater from gasification and carbon capture processes. EPA also obtained sampling data for surface impoundment and landfill leachate collection and treatment systems at 39 plants, as required by Part G of the Steam Electric Survey (described in Section 3.3). This leachate sampling is not included in the following description of the field sampling program.

EPA's field sampling program began during its detailed study and continued throughout this rulemaking effort. During the study, EPA conducted one- or two-day sampling episodes at six plants to characterize untreated wastewaters generated by coal-fired power plants, as well as to obtain a preliminary assessment of treatment technologies and best management practices for reducing pollutant discharges. The types of wastewaters sampled during the detailed study were untreated and treated FGD wastewater, fly ash wastewater, and bottom ash wastewater. See the *Steam Electric Power Generating Point Source Category: Final Detailed Study Report* for additional information on the sampling program completed during the detailed study [U.S. EPA, 2009b].

Following completion of the detailed study, EPA conducted a sampling program at steam electric power plants to collect wastewater characterization data and treatment performance data associated with FGD wastewater and to collect data for other emerging wastestreams for which characterization data were not available (i.e., carbon capture and gasification wastewaters). As part of this sampling program, EPA conducted on-site sampling activities (i.e., samples were collected directly by EPA), as well as requiring some plants to collect samples for EPA (i.e., CWA 308 monitoring program). The following sections present information on the selection of plants sampled, the wastewater treatment systems sampled, and the sampling process for field sampling conducted following the completion of the detailed study.

3.4.1 <u>On-Site Sampling Activities</u>

3.4.1.1 United States

EPA conducted four-day sampling episodes at seven U.S. plants to obtain the following: 1) wastewater characterization data and 2) wastewater treatment technology performance data. EPA used these data in combination with other industry-supplied data to evaluate wastewater discharges resulting from steam electric power plants and to evaluate technology options for handling and treating these wastewaters. The sampling program primarily focused on the wastewaters associated with the operation of wet FGD systems. EPA collected information to characterize the untreated FGD scrubber purge wastewater, as well as treated FGD wastewater from chemical precipitation and biological treatment systems.

The sampling characterized the wastewaters generated by wet FGD scrubbers and the treatment performance of the systems used to treat the FGD scrubber purge wastewaters. EPA also collected field quality control (QC) samples consisting of bottle blanks, field blanks, equipment blanks, and duplicate samples, and laboratory QC samples used for matrix spike/matrix spike duplicate analyses.

EPA's sampling program also collected data in order to perform an engineering assessment of the design, operation, and performance of treatment systems at steam electric power plants. Specifically, EPA collected information regarding system design and day-to-day operation.

EPA considered the following characteristics to select plants for sampling:

- **Coal-Fired Boilers**: All of the plants selected for the sampling program were coal-fired plants because the wastestreams of interest for the sampling program data objectives are associated with coal-fired power plants.
- **Wet FGD System**: EPA evaluated wastewaters generated from wet FGD systems and the treatment of these wastewaters. EPA considered the following selection criteria regarding FGD systems:
  - *Type of FGD Wastewater Treatment System*: The primary factor for selection was the type of wastewater treatment system being operated to treat FGD wastewater. EPA selected plants operating the following types of wastewater treatment systems, which are the basis for the technology options:
    - Chemical precipitation;
    - Biological treatment; and
    - Vapor-compression evaporation.
  - *Age of FGD Wastewater Treatment System:* EPA collected samples from wastewater treatment systems that reached steady-state operation. EPA sampled FGD wastewater treatment systems that had been operating for at least six months and that plant staff considered the system to have reached a pseudo-steady state condition past the initial commissioning period.
  - *Type of FGD System*: EPA considered the type of FGD system operated by the plant (e.g., limestone forced oxidation, lime inhibited oxidation) when selecting plants for sampling. Plants generating FGD scrubber wastewater typically operate limestone forced oxidation (LSFO) FGD systems. The LSFO system has the capability of producing wallboard-grade gypsum, but it typically requires a purge stream that needs to be treated prior to discharge.[9]
- **NO_x Controls**: EPA considered whether the plants operate a selective catalytic reduction (SCR) system or a selective noncatalytic reduction (SNCR) system. Although these NO_x control systems do not generate a specific wastewater stream, their operation may affect the FGD wastewater characteristics as well as the fly ash and associated fly ash sluice water characteristics.
- **Power Load Cycling**: EPA considered a plant’s load cycling (i.e., baseload, cycling, peaking) because the production load could potentially affect the FGD wastewater

[9] EPA did not select any plants operating inhibited oxidation FGD systems or once-through FGD systems for sampling after completion of the detailed study because EPA did not identify any plants that operate these systems and also operate a chemical precipitation or biological treatment system. The wastewater pollutants present in these systems are similar to those generated by LSFO systems because the scrubbing process will capture the same types of pollutants from the flue gas. The technologies used to treat wastewater from a recirculating LSFO FGD system would also be effective at treating the wastewater from inhibited oxidation or once-through LSFO FGD systems.

characteristics Most of the plants selected for sampling were baseload plants; however, plants with cycling units were also selected.

- **Type of Coal:** EPA considered the type of coal that the plant burns and selected plants burning different types of coal because the types and concentration of metals present in the FGD wastewater could differ based on the fuel source. Most of the plants sampled burn bituminous coal because the majority of plants with wet FGD systems burn bituminous coal; however, EPA also sampled wastewater at plants that burn subbituminous coal.

EPA selected and conducted sampling activities at the following plants in the U.S.:

- Duke Energy Carolina's Belews Creek Steam Station;
- We Energies' Pleasant Prairie Power Plant;
- Duke Energy's Miami Fort Station;
- Duke Energy Carolina's Allen Steam Station;
- Mirant Mid-Atlantic, LLC's Dickerson Generating Station;
- RRI Energy's Keystone Generating Station; and
- Allegheny Energy's Hatfield's Ferry Power Station.

All of the selected plants operate chemical precipitation wastewater treatment systems to treat their FGD wastewater. The treatment systems at Belews Creek, Allen, and Dickerson also include a biological treatment stage following the chemical precipitation. Table 3-3 presents the selection details for each sampled plant.

The pollutants selected for analysis reflected the current understanding of FGD wastewaters, including contributions from the fuel, scrubber sorbents, treatment chemicals, and other sources. Table 3-4 lists the analytical methods that EPA used for each analyte. In addition to these analytes, EPA collected field measurements at all sampling points including temperature and pH.

Table 3-3. Selection Criteria for Plants Included in EPA's Sampling Program in the United States

Plant Name	Selection Criteria							
	Coal-Fired Boilers	FGD Treatment System		Type of FGD System	NOx Controls	Power Load Cycling	Type of Coal	Commercial-Grade Gypsum By-product
		Chemical Precipitation	Biological					
Belews Creek	Yes	Yes[1,3]	Yes[5]	LSFO	SCR	Baseload	Eastern Bituminous	Yes
Pleasant Prairie	Yes	Yes[2,4]	No	LSFO	SCR	Baseload	Subbituminous (Powder River Basin)	Yes
Miami Fort	Yes	Yes[2]	No	LSFO	SCR	Baseload	Eastern Bituminous	Yes
Allen	Yes	Yes[1,3]	Yes[5]	LSFO	SNCR	Cycling	Bituminous	Yes
Dickerson	Yes	Yes[1,3]	Yes[6]	LSFO	SNCR	Cycling	Eastern Bituminous	Yes
Keystone	Yes	Yes[2]	No	LSFO	SCR	Baseload	Eastern Bituminous	No
Hatfield's Ferry	Yes	Yes[2]	No	LSFO	SNCR	Baseload	Bituminous, Subbituminous (Powder River Basin)	No

1 - The chemical precipitation system at these plants include hydroxide precipitation and iron coprecipitation, but do not include sulfide precipitation as part of the process.

2 - The chemical precipitation system at these plants include hydroxide precipitation, sulfide precipitation, and iron coprecipitation.

3 - The chemical precipitation system at these plants precede a biological treatment stage.

4 - Two-stage chemical precipitation treatment. All other sampled plants use one-stage chemical precipitation.

5 - Anoxic/anaerobic biological system primarily designed to remove selenium.

6 - Sequencing batch reactor (SBR) primarily designed for nutrient removal (nitrification/denitrification).

Table 3-4. Analytical Methods Used for EPA's Sampling Program

Parameter	Method Number
Classicals	
Biochemical oxygen demand (BOD_5)	SM 5210 B
Chemical oxygen demand (COD)	EPA 410.4
Total suspended solids (TSS)	SM 2540 D
Total dissolved solids (TDS)	SM 2540 C
Sulfate	EPA 300.0
Chloride	EPA 300.0
Ammonia as nitrogen	EPA 350.1
Nitrate/nitrate as nitrogen	EPA 353.2
Total Kjeldahl nitrogen (TKN)	EPA 351.2
Total phosphorus	EPA 365.1
Total cyanide	SM 4500 CN E
Total and Dissolved Metals	
Mercury	EPA 1631E
Hexavalent chromium (dissolved only)	EPA 218.6
Antimony, arsenic, cadmium, chromium, copper, lead, manganese, nickel, selenium, silver, thallium, and vanadium	EPA 200.8 with collision cell
Aluminum, barium, beryllium, boron, calcium, cobalt, iron, magnesium, molybdenum, sodium, tin, titanium, and zinc[1]	EPA 200.7

a - Zinc was analyzed using EPA Method 200.8 with collision cell for the Belews Creek, Pleasant Prairie, Miami Fort, and Allen sampling episodes, but was analyzed by EPA Method 200.7 for the Dickerson, Keystone, and Hatfield's Ferry sampling episodes. EPA changed methods because it was observing high concentrations of zinc in the influent and effluent samples that were more suited for analysis by EPA Method 200.7.

EPA collected representative samples at the influent and effluent of the FGD wastewater treatment systems and, where applicable, the mid-point of the FGD treatment system (i.e., effluent from chemical precipitation system prior to biological treatment). EPA collected 24-hour composite samples at the mid-point and effluent sampling points for all analytes except mercury and cyanide. At the mid-point and effluent sampling points, EPA collected cyanide as a single grab sample and mercury as four individual grab samples over the 24-hour period (i.e., a grab sample collected every six hours). All influent samples were collected as grab samples.

Sampling episode reports describing the sample collection activities and the analytical results from the seven on-site sampling episodes are included in the rulemaking record. [ERG, 2012a – 2012g]

3.4.1.2 Italy

In April 2011, EPA conducted a three-day sampling episode at Enel's Federico II Power Plant (Brindisi), located in Brindisi, Italy. The purpose was to characterize untreated FGD scrubber purge and treated FGD wastewater from an FGD wastewater treatment system consisting of chemical precipitation followed by mechanical vapor-compression evaporation.

The mechanical vapor-compression evaporation system used a falling-film brine concentrator to produce a concentrated wastewater stream and a reusable distillate stream. The concentrated wastewater stream was further processed in a forced-circulation crystallizer, in which a solid product was generated along with a reusable condensate stream.

In addition to collecting the samples of untreated FGD scrubber purge and treated FGD wastewater, EPA also collected field QC samples consisting of bottle blanks, field blanks, equipment blanks, field duplicate samples, and laboratory QC aliquots used for matrix spike/matrix spike duplicate analyses.

Brindisi was selected by EPA for sampling because it operates a one-stage chemical precipitation system followed by softening and a two-stage vapor-compression evaporation system for the treatment of FGD wastewater. The following are the characteristics of the Brindisi plant:

- The plant is a coal-fired power plant;
- The plant operates limestone forced oxidation wet FGD systems on all four units;
- The plant operates a segregated FGD wastewater treatment system, which includes the following steps:
  - Settling,
  - Equalization,
  - Lime, sodium sulfide, and caustic soda addition (pH adjustment/metal hydroxide precipitation),
  - Ferric chloride addition,
  - Polyelectrolyte addition,
  - Clarification,
  - Ferrous chloride and soda ash addition (softening),
  - Clarification,
  - Evaporation (brine concentrator),
  - Crystallization; and
- The plant operates selective catalytic reduction (SCR) systems on all four units.

EPA collected samples for the same list of analytes listed in Table 3-4, except for excluding the following analytes either because of holding time considerations or time constraints for the sampling event:

- BOD5;
- Total cyanide; and
- Dissolved metals (all analytes).

EPA also collected field measurements at all sampling points including temperature and pH.

EPA collected representative samples of the influent to the FGD wastewater treatment system, the distillate from the brine concentrator, and the condensate from the crystallizer. EPA collected six-hour composite samples at the brine concentrator and crystallizer sampling points for all analytes except mercury. At the brine concentrator and crystallizer sampling points, EPA collected mercury as three individual grab samples over the six-hour period (i.e., a grab sample collected every two hours). EPA collected all analytes at the influent to the FGD wastewater treatment system as one-day grab samples.

A sampling episode report describing the sample collection activities and the analytical results from this sampling episode are included in the rulemaking record. [ERG, 2012h]

EPA also requested that a second plant in Italy, A2A's Centrale di Monfalcone (Monfalcone), collect one-day grab samples. Monfalcone operates a chemical precipitation followed by vapor-compression evaporation system to treat FGD wastewater. Monfalcone personnel collected samples of the FGD influent to wastewater treatment, the distillate from the brine concentrator, and the condensate from the crystallizer. Site visit notes and the corresponding analytical results are included in the rulemaking record. [ERG, 2013]

3.4.2 CWA 308 Monitoring Program

EPA required a subset of steam electric power plants to collect samples that were used to supplement the EPA on-site sampling program. Each of the seven plants selected for the on-site sampling program (except for the Italian plant) were required to participate in the CWA 308 monitoring program so EPA could evaluate the variability associated with the FGD wastewaters treatment systems performance.

For those seven plants, in addition to the samples collected by EPA during the four-day on-site sampling event, EPA required the plants to collect four sets of samples over a four- or five-month period. The samples were collected directly by the plants and shipped to EPA-contracted laboratories for analysis.

EPA required four additional plants (not sampled by EPA) to participate in its CWA 308 monitoring program. These plants were selected to obtain data about operations or treatment systems because EPA did not have existing data for these processes or treatment technologies. EPA obtained data from the following four plants:

- Tampa Electric Company's Polk Station (first of only two currently operating integrated gasification combined cycle (IGCC) plants);
- Wabash Valley Power Association's Wabash River Station (second of only two currently operating IGCC plants);
- Appalachian Power Company's Mountaineer Plant (only plant operating a carbon capture system that is of interest to EPA); and
- Kansas City Power & Light's Iatan Station (only plant in United States operating a one-stage vapor-compression evaporation system for treatment of FGD wastewater).

For these four plants, EPA required the plants to collect four consecutive days of samples at two to four locations specifically identified for each plant. The sample locations were identified to characterize gasification wastewaters, carbon capture wastewaters, and the treatment of FGD wastewater and gasification wastewater by vapor-compression evaporation systems. EPA used the same four-consecutive-day sampling approach that was used for EPA's on-site sampling program (as described in Section 3.4.1). These samples were collected directly by the plants and shipped to EPA-contracted laboratories for analysis.

A report describing the results from the CWA 308 monitoring program is included in the rulemaking record. [ERG, 2012i]

3.5 EPA AND STATE SOURCES

EPA collected information from databases, publications, and state groups and permitting authorities, including the following sources discussed below:

- Information on current and proposed permitting practices for the steam electric industry from a review of selected National Pollutant Discharge Elimination System (NPDES) permits and accompanying fact sheets;
- Input from EPA and state permitting authorities regarding implementation of the existing Steam Electric Power Generating ELGs;
- Background information on the steam electric industry from documents prepared during the development of the existing Steam Electric Power Generating ELGs (i.e., the 1974 and 1982 rulemakings);
- Information from a survey of the industry conducted in support of the CWA section 316(b) Cooling Water Intake Structures rulemaking;
- Information from EPA's OAR, including Integrated Planning Model (IPM) projections based on recent air rules (i.e., Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS));
- Information from EPA's Office of Research and Development (ORD) characterizing CCRs and the potential leaching of pollutants from CCRs stored or disposed of in landfills and surface impoundments;
- Information from EPA's Office of Research and Development (ORD) characterizing CCRs and the potential leaching of pollutants from CCRs stored or disposed of in landfills and surface impoundments
- Data provided by the North Carolina Department of Environment and Natural Resources for one plant that operates an anoxic/anaerobic biological treatment system for FGD wastewater; and
- Information collected by EPA's OSWER, regarding surface impoundments or other similar management units that contain CCRs at power plants and other information gathered in support of the proposed rule for regulating CCRs under the Resource Conservation and Recovery Act (RCRA).

EPA's Office of Water (OW) has coordinated its efforts with ongoing research and activities being undertaken by the EPA offices listed above. In addition, EPA's OW has also coordinated with the Office of Enforcement and Compliance Assurance (OECA) and EPA regional offices to gather further information on the industry.

3.5.1 NPDES Permits and Fact Sheets

The CWA requires direct dischargers (i.e., industrial facilities that discharge process wastewaters from any point source into receiving waters) to control their discharges according to ELGs and water-quality-based effluent limitations included in NPDES permits. EPA collected and reviewed selected NPDES permits and, where available, accompanying fact sheets to confirm or help clarify information reported in the survey responses.

3.5.2 State Groups and Permitting Authorities

Throughout the detailed study and rulemaking, EPA interacted with states and EPA regional permitting authorities, such as when contacting and visiting steam electric power plants. EPA also solicited input and suggestions from states and permitting authorities on specific steam electric power plant characteristics, ICR development, and implementation of the Steam Electric Power Generating ELGs. EPA hosted a webcast seminar in December 2008 to review information on wastewater discharges from power plants for NPDES permitting and pretreatment authorities. The webcast provided an update on EPA's review of the current ELGs (40 CFR 423) and presented information on pollutant characteristics and treatment technologies for wastewater from FGD scrubbers. During the webcast, state and interstate approaches for managing steam electric power plant wastewaters were shared by representatives from Wisconsin, North Carolina, and the Ohio River Valley Water Sanitation Commission (ORSANCO).

In November 2009, EPA held conference calls with states and EPA permitting authorities to discuss development and input for the ICR [ERG, 2009]. Additionally, EPA held a joint Federalism/Unfunded Mandates Reform Act (UMRA) consultation meeting in October 2011 to request input regarding the Steam Electric Power Generating ELGs [U.S. EPA, 2011b].

EPA participated in periodic conference calls with ORSANCO during the rulemaking to discuss treatment technologies for managing wastewaters from steam electric power plants.

Additionally, EPA coordinated with the state of North Carolina to obtain long-term characterization data from Progress Energy Carolinas' Roxboro Steam Electric Plant for the FGD wastewater treatment influent, FGD impoundment effluent, and biological treatment effluent, as well as ash impoundment effluent data [NCDENR, 2011].

3.5.3 1974 and 1982 Technical Development Documents for the Steam Electric Power Generating Point Source Category

Two documents prepared by EPA during previous rulemakings for the Steam Electric Category have provided useful information for the current rulemaking. These documents are the 1974 *Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category* (referred to in this report as "the 1974 Development Document") (U.S. EPA, 1974) and the 1982 *Development Document for Effluent Limitations Guidelines and Standards and Pretreatment Standards for the Steam Electric Point Source Category* (referred to in this report as "the 1982 Development Document") (U.S. EPA, 1982). These development documents contain findings, conclusions, and recommendations on control and treatment technology relating to discharges from steam electric power plants. During this rulemaking, EPA used the information presented in the 1974 and 1982 Development Documents for historical background on the Steam Electric Power Generating ELGs and for information on sources of pollutants and wastewater characteristics.

3.5.4 CWA Section 316(b) - Cooling Water Intake Structures Supporting Documentation and Data

For the CWA section 316(b) Cooling Water Intake Structures rulemaking, EPA conducted a survey of steam electric utilities and steam electric non-utilities that use cooling water, as well as facilities in four other manufacturing sectors: Paper and Allied Products (Standard Industrial Classification (SIC) code 26), Chemical and Allied Products (SIC code 28), Petroleum and Coal Products (SIC code 29), and Primary Metals (SIC code 33). The survey requested the following types of information:

- General plant information, such as plant name, location, and SIC codes;
- Cooling water source and use;
- Design and operational data on cooling water intake structures and cooling water systems;
- Studies of the potential impacts from cooling water intake structures conducted by the facility; and
- Financial and economic information about the facility.

Although the Section 316(b) survey was used to create guidelines for cooling water intake structures, the cooling water system information collected in the survey was also useful for this rulemaking effort. EPA used the information provided by the Section 316(b) survey in the following analyses:

- Identifying plant-specific cooling water sources (e.g., specific rivers, streams);
- Identifying industrial non-utilities;
- Identifying the type of cooling systems used by plants;
- Linking EIA plant information to the Toxic Release Inventory (TRI) and Permit Compliance System (PCS) discharges; and
- Determining plant-specific wastewater dilutions associated with cooling water prior to discharge for the Environmental Assessment (EA) analyses associated with the rulemaking effort.

3.5.5 Office of Air and Radiation

EPA's OAR works to control air pollution and radiation exposure and takes action on climate change by developing regulations under the Clean Air Act (CAA), and developing national programs and technical policies. OAR relies on the Integrated Planning Model (IPM) for some of its analyses of the effects of policies on the electric power sector. IPM is an engineering-economic optimization model of the electric power industry, which generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. The model uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand-supply equilibrium on a seasonal basis and by region. In addition to existing capacity, the model also considers new resource investment options, including capacity expansion at existing plants, as well as investment in new plants. The model is dynamic in that it is capable of using forecasts of future conditions to make decisions for the present. IPM Version 4.10 MATS (IPM V4.10) incorporates in its analytic baseline the expected compliance response for the following air regulations affecting the power sector: the final Mercury and Air Toxics Standards (MATS) rule; the final Cross-State Air Pollution Rule (CSAPR); regulatory SO_2 emission rates arising from State Implementation Plans; Title IV of the Clean Air Act Amendments; NOx SIP Call trading program; Clean Air Act Reasonable Available Control Technology requirements and Title IV unit specific rate limits for NOx; the Regional Greenhouse Gas Initiative; Renewable Portfolio Standards; New Source Review Settlements; and several state-level regulations affecting emissions of SO_2, NOx, and Hg that were either in effect or expected to come into force by 2017.

Thus, IPM V4.10 projects the characteristics of electricity generation for various "plant types" in the future, considering the expected impacts of regulations [U.S. EPA, 2011a]. EPA used the output from the MATS policy case for run year 2015 to identify potential future wet FGD scrubber installation that may not be accounted for in the survey responses. EPA used these data to inform a "future" profile of the industry, which is discussed in Section 8.1.7.

3.5.6 Office of Research and Development

EPA's ORD is evaluating the impact of air pollution controls on the characteristics of CCRs. Specifically, ORD is studying the potential cross-media transfer of mercury and other metals from flue gas, fly ash, and other residuals collected from coal-fired boiler air pollution controls and disposed of in landfills or impoundments. The key routes of release being studied are leaching into ground water or subsequent release into surface waters, re-emission of mercury, and bioaccumulation. ORD is also examining the use of CCRs in asphalt, cement, and wallboard production.

The goal of the research is to better understand potential impacts from disposal practices and beneficial use of CCRs. The research evaluates life-cycle environmental tradeoffs that compare beneficial use applications with and without using CCRs. The outcome of this research will help to identify potential management practices of concern where environmental releases may occur, such as developing and applying a leach testing framework that evaluates a range of materials and the different factors affecting leaching for the varying field conditions in the environment.

EPA's OW consulted with the ORD on the status and findings of current research assessing the potential for CCRs to impact water quality. Additionally, during EPA's sampling program, OW collected samples of CCR landfill leachate from several of the plants for characterization analysis by ORD.

3.5.7 Office of Solid Waste and Emergency Response

On June 21, 2010, EPA proposed the *Hazardous and Solid Waste Management System: Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities* (i.e., the CCR rule) (75 FR 35128; June 21, 2010). The proposed rule would regulate coal ash to address the risks from the disposal of the wastes generated by electric utilities and independent power producers. EPA used data collected by EPA's OSWER to supplement the data collected for the ELGs. EPA also used costing methodologies developed by EPA's OSWER in some of the costing approaches for the proposed ELGs, if appropriate.

As part of the proposed CCR rule development, EPA's OSWER issued Information Request Letters to electric utilities that have surface impoundments or similar management units that contain CCRs. EPA's OSWER identified the recipients of the request letters based on plants that potentially operate CCR surface impoundments identified from data compiled in DOE's EIA databases. However, the EIA data do not include information about waste disposal practices for those plants with a nameplate electric generating capacity of less than 100 MW. Additionally, the EIA data excludes information about impoundments at plants that use the impoundment as an interim step (e.g., to dewater ash or other CCR solids), but ultimately dispose of the CCRs in an on-site landfill or off site. Therefore, OSWER may not have identified the plants operating these types of impoundments as potential recipients. As such, data collected by the OSWER survey underestimates the total number of CCR impoundments nationwide.

As explained in Section 1.3.3, because the CCR rule has not been finalized, EPA cannot factor in with certainty how any operational changes associated with any final CCR rule may impact the analyses for the proposed ELGs. Therefore, the analyses presented for the proposed ELGs represent current industry operations, without implementation of new requirements contemplated by the CCR rule. Rather, EPA conducted a sensitivity analyses to see how any final CCR rule might impact the analyses for the proposed ELGs. See DCN SE02123.

3.6 INDUSTRY-SUBMITTED DATA

EPA obtained information on steam electric processes, technologies, wastewaters, and pollutants directly from the industry through self-monitoring data, as well as NPDES Form 2C data.

3.6.1 Self-Monitoring Data

EPA requested self-monitoring data from Duke Energy's Belews Creek Steam Station and Allen Steam Station to evaluate the treatment efficiency and pollutant characteristics of wastewater discharged from FGD wastewater treatment systems that incorporate both chemical precipitation and biological treatment (Duke Energy, 2011a and 2011b). EPA also used these data to supplement the data from the EPA sampling program.

3.6.2 NPDES Form 2C

UWAG and EPA coordinated efforts to create a database of selected NPDES Form 2C data from UWAG's member companies. Form 2C (or an equivalent form used by a state permitting authority) is an application for a permit to discharge wastewater that must be completed by industrial facilities (including manufacturing, commercial, mining, and silvicultural operations). This form includes facility information, data on facility outfalls, process flow diagrams, treatment information, and intake and effluent characteristics.

The Form 2C database contains information about the outfalls of coal-fired power plants that receive FGD, ash handling, or coal pile runoff wastestreams. EPA received Form 2C data from UWAG for 86 plants in late June 2008 [UWAG, 2008]. UWAG did not include data on other outfalls, such as separate outfalls for sanitary wastes, cooling water, landfill runoff, and other wastestreams, in the database. The database does not include Form 2C information for plants that have neither a wet FGD system nor wet fly ash handling. For example, if a plant has no wet FGD system and the plant's only wet ash handling is for bottom ash transport, UWAG did not include its information in the database. EPA used the Form 2C data for developing a preliminary industry profile and the survey, but these outfall data were eventually superseded by the data received in response to the survey.

3.7 TECHNOLOGY VENDOR DATA

EPA gathered data from technology vendors through presentations, conferences, meetings, and email and phone contacts regarding the technologies used in the industry. The data collected informed the development of the detailed study, the industry survey, and technology costs and loadings estimates. Between 2007 and 2012, EPA participated in multiple technical conferences and reviewed the papers presented.

To gather FGD wastewater treatment information for the cost analyses, EPA contacted companies that manufacture, distribute, or install various components of chemical precipitation and biological wastewater treatment systems and vapor-compression evaporation. The vendors provided the following types of information for EPA's analyses:

- Operating details;
- Performance data;
- Equipment used in the system;
- Capital cost information on a component level and system level;
- Operating and maintenance costs; and
- Equipment and system energy requirements.

To gather information on handling of fly ash and bottom ash, EPA also contacted several ash handling and ash storage vendors. The vendors provided the following types of information for EPA's analyses:

- The type of fly ash and bottom ash handling systems available for handling ash dry or in closed-loop recycle;

- Equipment and modifications required to convert wet fly ash and bottom ash handling systems to dry handling or closed-loop recycle systems;
- Equipment that can be reused as part of the conversion from wet to dry handling or in a closed-loop recycle system;
- Outage time required for the different types of ash handling systems;
- Maintenance required for each type of system;
- Operating data for each type of system;
- Equipment and installation capital costs for fly ash and bottom ash conversion;
- The specifications for the types of ash storage available for the different types of handling systems;
- The equipment and installation capital costs associated with the storage of fly ash and bottom ash; and
- Operating and maintenance costs for fly ash and bottom ash handling systems.

To obtain additional information on FGD treatment systems and fly ash and bottom ash conversions, EPA held meetings, conference calls, and site visits with treatment and ash vendors.

3.8 OTHER SOURCES

EPA obtained additional information on steam electric processes, technologies, wastewaters, pollutants, and regulations from sources including trade associations, the Electric Power Research Institute (EPRI), DOE, the U.S. Geological Survey (USGS), UWAG, and literature and Internet searches.

3.8.1 Utility Water Act Group

UWAG is an association of over 200 individual electric utilities and four national trade associations of electric utilities: the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, and the Nuclear Energy Institute. UWAG's purpose is to participate on behalf of its members in EPA's rulemakings under the CWA. Specifically, EPA coordinated with UWAG on collecting information on power plant characteristics to support site visit selection, discussing wastewater sampling approaches and recommendations, laboratory analytical methods, reviewing the questionnaire for clarity, reviewing the questionnaire mailing list to confirm plants and mailing addresses, and collecting existing permit data. At the invitation of individual plants, UWAG representatives also collected split samples during EPA's on-site sampling and CWA 308 monitoring programs and participated in most site visits.

3.8.2 Electric Power Research Institute

EPRI is a research-oriented trade association for the steam electric industry. EPRI conducts research funded by the steam electric industry and has extensively studied wastewater discharges from FGD systems. The trade association provided EPA with the following reports that summarize the data collected during several EPRI studies:

- Flue Gas Desulfurization (FGD) Wastewater Characterization: Screening Study (EPRI, 2006a);
- EPRI Technical Manual: Guidance for Assessing Wastewater Impacts of FGD Scrubbers (EPRI, 2006b);
- The Fate of Mercury Absorbed in Flue Gas Desulfurization (FGD) Systems (EPRI, 2005);
- Update on Enhanced Mercury Capture by Wet FGD: Technical Update (EPRI, 2007);
- PISCES Water Characterization Field Study, Sites A-G (EPRI, 1997b-2001);
- Selenium Removal by Iron Cementation from a Coal-Fired Power Plant Flue Gas Desulfurization Wastewater in a Continuous Flow System – A Pilot Study (EPRI, 2009a); and
- Laboratory and Pilot Evaluation of Iron and Sulfide Additives with Microfiltration for Mercury Water Treatment (EPRI, 2009b).

The EPRI reports provided EPA with background information regarding the characteristics of FGD wastewaters and the sampling techniques used during the program. These reports also provided EPA with information regarding the characteristics of discharges from fly ash and bottom ash impoundments and the respective percentage of loadings from ash impoundments containing both fly ash and bottom ash. Additionally, the EPRI reports provided information on the treatment technologies available to treat FGD and ash wastewaters, including findings from pilot-study evaluations.

EPRI also participated in meetings with EPA and provided comments on EPA's planned data collection activities, including the survey and the sampling program.

3.8.3 Department of Energy (DOE)

DOE is the department of the United States government responsible for energy policy. EPA used information on electric generating plants from DOE's EIA data collection forms.

The Agency used information from two of EIA's data collection forms: Form EIA-860, Annual Electric Generator Report, and Form EIA-923, Power Plant Operations Report. Form EIA-860 collects information annually from all electric generating facilities that have or will have a nameplate capacity of 1 MW or more and are operating or plan to be operating within five years of filing this form.[10] The data collected in Form EIA-860 are associated only with the design and operation of generators at facilities [U.S. DOE, 2007a and 2009a]. Form EIA-923 collects information from electric power plants and combined heat and power plants in the United States that have a total generator nameplate capacity greater than 1 MW. The form asks where the generator(s), or the facility in which the generator(s) resides, and if it is connected to

[10] DOE defines the generator nameplate capacity as the maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in kilowatts (kW) on a nameplate physically attached to the generator. More generally, generator capacity is the maximum output, commonly expressed in MW, that generating equipment can supply to system load, adjusted for ambient conditions.

the local or regional electric power grid and has the ability to draw power from the grid or deliver power to the grid. The data collected in Form EIA-923 are associated with the operation and design of the entire facility [U.S. DOE, 2007b and 2009b]. EPA used these data to help identify the industry the sample frame for the Steam Electric Survey. Additionally, EPA used these data to supplement Steam Electric Survey data, such as age of the generating units, which was not included in the survey.

3.8.4 Literature and Internet Searches

EPA conducted literature and Internet searches to obtain information on various aspects of the steam electric process, both for plants regulated by the ELGs and certain operations outside the scope of the regulations for which EPA evaluated whether they could/should be covered by the ELGs. The objectives of these searches included characterizing wastewaters and pollutants originating from these steam electric processes, the environmental impacts of these wastewaters, and applicable regulations. EPA also used the Internet searches to identify or confirm reports of planned plant/unit retirements or reports of planned unit conversions to dry or closed-loop recycle ash handling systems. EPA used industry journals, reference texts about the industry, and company press releases obtained from Internet searches to inform the industry profile and process modifications occurring in the industry.

3.8.5 Environmental Groups and Other Stakeholders

EPA received information from several environmental groups and other stakeholders as part of public comments submitted for the 2006 and 2008 Effluent Guidelines Plans, the survey, and in other discussions during the detailed study and rulemaking. In general, the information highlighted environmental concerns associated with the pollutants present in steam electric power plant wastewaters, and technological controls for reducing or eliminating pollutant discharges from FGD and ash handling systems.

3.9 PROTECTION OF CONFIDENTIAL BUSINESS INFORMATION

Certain data in the rulemaking record have been claimed as confidential business information (CBI). The Agency has withheld CBI from the public docket in the Federal Docket Management System. In addition, the Agency has withheld from disclosure some data not claimed as CBI because the release of these data could indirectly reveal CBI. Furthermore, EPA has aggregated certain data in the public docket, masked plant identities, or used other strategies to prevent the disclosure of CBI. The Agency's approach to CBI protection ensures that the data in the public docket both explain the basis for the proposed rule and provide the opportunity for public comment, without compromising data confidentiality.

3.10 REFERENCES

1. Duke Energy. 2011a. Industry Provided Sampling Data from Duke Energy's Allen Steam Station. (17 August). DCN SE01809
2. Duke Energy. 2011b. Industry Provided Sampling Data from Duke Energy's Belews Creek Steam Station. (17 August). DCN SE01808

3. Eastern Research Group (ERG). 2009. Memorandum to Ron Jordan, US EPA. "Outreach Calls for the Proposed Steam Electric ICR." (25 February). DCN SE00203.
4. Eastern Research Group (ERG). 2012a. Final Sampling Episode Report, Duke Energy Carolinas' Belews Creek Steam Station. (13 April). DCN SE01305.
5. Eastern Research Group (ERG). 2012b. Final Sampling Episode Report, We Energies' Pleasant Prairie Power Plant. (13 April). DCN SE01306.
6. Eastern Research Group (ERG). 2012c. Final Sampling Episode Report, Duke Energy Miami Fort Station. (13 April). DCN SE01304.
7. Eastern Research Group (ERG). 2012d. Final Sampling Episode Report, Duke Energy Carolinas' Allen Steam Station. (13 April). DCN SE01307.
8. Eastern Research Group (ERG). 2012e. Final Sampling Episode Report, Mirant Mid-Atlantic, LLC's Dickerson Generating Station. (13 April). DCN SE01308.
9. Eastern Research Group (ERG). 2012f. Final Sampling Episode Report, Allegheny Energy's Hatfield's Ferry Power Station. (13 April). DCN SE01310.
10. Eastern Research Group (ERG). 2012g. Final Sampling Episode Report, RRI Energy's Keystone Generating Station. (13 April). DCN SE01309.
11. Eastern Research Group, Inc. (ERG). 2012h. Final Site Visit Notes and Sampling Episode Report for Enel's Power Plants. (8 August). DCN SE02013.
12. Eastern Research Group (ERG). 2012i. Final Power Plant Monitoring Data Collected Under Clean Water Act Section 308 Authority ("CWA 308 Monitoring Data"). (30 May). DCN SE01326.
13. Eastern Research Group (ERG). 2013. Final Monfalcone Site Visit Notes. (11 March). DCN SE03795 and SE03796.
14. Electric Power Research Institute (EPRI). 1997b - 2001. PISCES Water Characterization Field Study, Sites A-G. Palo Alto, CA. DCN SE01818 through SE01823.
15. Electric Power Research Institute (EPRI). 2005. The Fate of Mercury Absorbed in Flue Gas Desulfurization (FGD) Systems. 1009955. Palo Alto, CA. (March). DCN SE01814.
16. Electric Power Research Institute (EPRI). 2006a. Flue Gas Desulfurization (FGD) Wastewater Characterization: Screening Study. 1010162. Palo Alto, CA. (March). DCN SE01816.
17. Electric Power Research Institute (EPRI). 2006b. EPRI Technical Manual: Guidance for Assessing Wastewater Impacts of FGD Scrubbers. 1013313. Palo Alto, CA. (December). Available online at: http://www.epriweb.com/public/000000000001013313.pdf. Date accessed: 16 May 2008. DCN SE01817.
18. Electric Power Research Institute (EPRI). 2007. Update on Enhanced Mercury Capture by Wet FGD: Technical Update. 1012673. Palo Alto, CA. (March). DCN SE01815.
19. Electric Power Research Institute (EPRI). 2009a. Laboratory and Pilot Evaluation of Iron and Sulfide Additives with Microfiltration for Mercury Water Treatment. 1016813. Palo Alto, CA. (March). DCN SE00409A3.

20. Electric Power Research Institute (EPRI). 2009b. Selenium Removal by Iron Cementation from a Coal-Fired Power Plant Flue Gas Desulfurization Wastewater in a Continuous Flow System – Pilot Study. 1017956. Palo Alto, CA. (July). DCN SE00409A2.
21. NCDENR. 2011. North Carolina Department of Environment and Natural Resources (NCDENR) State Provided Sampling Data From North Carolina's Progress Energy Roxboro Plant. (26 June). DCN SE01812.
22. U.S. DOE. 2007a. U.S. Department of Energy. Annual Electric Generator Report (collected via Form EIA-860). Energy Information Administration (EIA). The data files are available online at: http://www.eia.gov/electricity/data/eia860/index.html. DCN SE02014.
23. U.S. DOE. 2007b. U.S. Department of Energy. Power Plant Operations Support (collected via Forms EIA-906/920/923). Energy Information Administration (EIA). The data files are available online at: http://www.eia.gov/electricity/data/eia923/. DCN SE02015.
24. U.S. DOE. 2009a. U.S. Department of Energy. Annual Electric Generator Report (collected via Form EIA-860). Energy Information Administration (EIA). The data files are available online at: http://www.eia.gov/electricity/data/eia860/index.html. DCN SE01805.
25. U.S. DOE. 2009b. U.S. Department of Energy. Power Plant Operations Support (collected via Form EIA-923). Energy Information Administration (EIA). The data files are available online at: http://www.eia.gov/electricity/data/eia923/. DCN SE02030.
26. U.S. EPA. 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C. (October). DCN SE02917.
27. U.S. EPA. 1982. *Development Document for Effluent Limitations Guidelines and Standards and Pretreatment Standards for the Steam Electric Point Source Category*. EPA-440-1-82-029. Washington, DC. (November). DCN SE02931.
28. U.S. EPA. 2009a. Office of Solid Waste and Emergency Response (OWSER), Summary Results from the 2009 OSWER Information Request. DCN SE02032.
29. U.S. EPA. 2009b. Steam Electric Power Generating Point Source Category: Final Detailed Study. EPA 821-R-09-008. Washington, D.C., (October). DCN SE00003.
30. U.S. EPA. 2011a. Office of Air and Radiation (OAR). Integrated Planning Model (IPM) 2015 MATS Policy Case Output. (December). DCN SE02047.
31. U.S. EPA. 2011b. Steam Electric ELG Rulemaking – UMRA and Federalism Implications: Consultation Meeting. (11 October). DCN SE03286 and SE03287.
32. Utility Water Act Group (UWAG). 2008. UWAG Form 2C Effluent Guidelines Database. (30 June). DCNs SE02918 and SE02918A1.

SECTION 4
STEAM ELECTRIC INDUSTRY DESCRIPTION

Electricity is produced by converting mechanical, chemical, and/or fission energy into electrical energy, and may or may not involve the use of steam. This section provides an overview of the various types of electric generating processes operating in the United States and describes more fully the categories of processes regulated by the Steam Electric Power Generating effluent limitations guidelines and standards (ELGs). Section 4.1 generally describes the electric generating industry, including demographics of the steam electric industry; Section 4.2 describes the steam electric power generating process; Section 4.3 describes the wastestreams generated by the steam electric industry that were evaluated for new or additional controls in the proposed ELGs; and Section 4.4 describes the wastestreams generated by the steam electric industry that were not evaluated for new or additional controls in the proposed ELGs.

4.1 OVERVIEW OF ELECTRIC GENERATING INDUSTRY

This section describes the types of plants that compose the overall electric generating industry as well as the definition of the Steam Electric Power Generating Point Source Category (Steam Electric Category). As shown in Figure 4-1, the plants regulated by the Steam Electric Power Generating ELGs are only a portion of the electric generating industry.

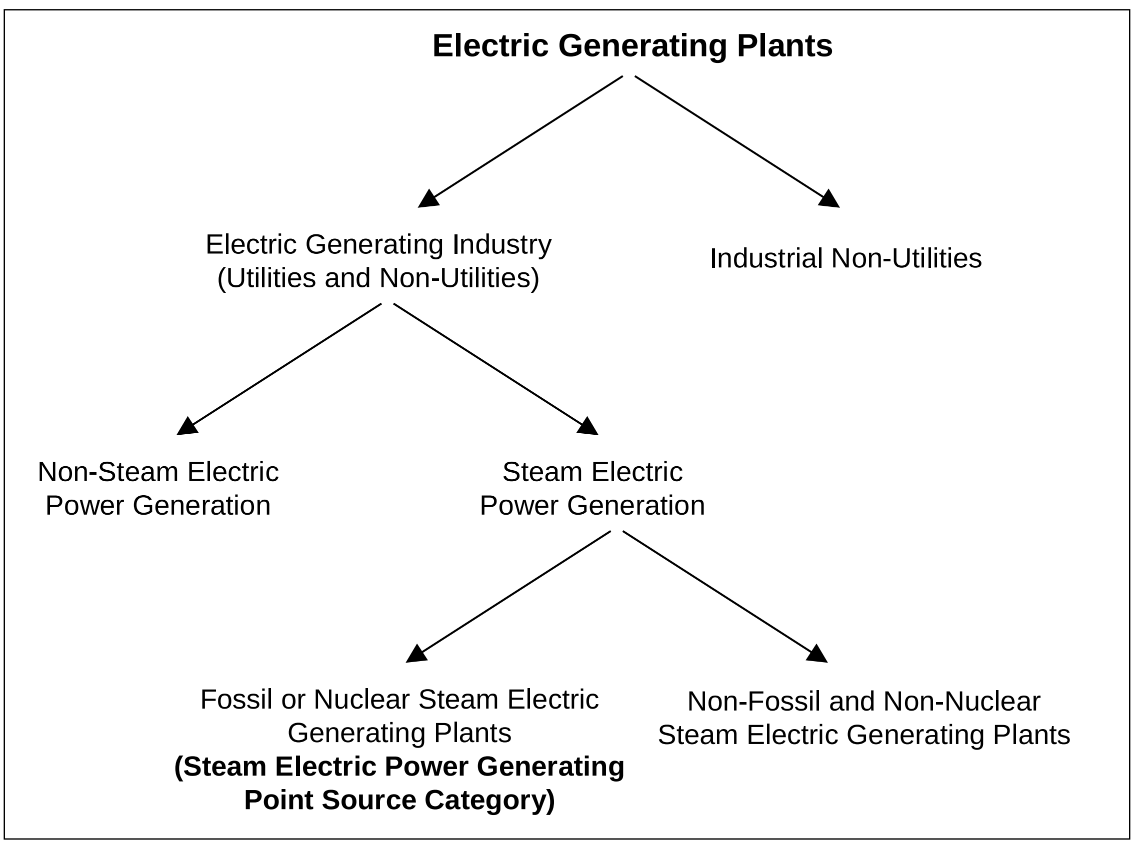


Figure 4-1. Types of U.S. Electric Generating Plants

4.1.1 Electric Generating Industry Population

In general, the companies generating electrical power are categorized as one of the following types:

- *Utility*: Any entity that generates, transmits, and/or distributes electricity and recovers the cost of its generation, transmission and/or distribution assets and operations, either directly or indirectly, through cost-based rates set by a separate regulatory authority (e.g., state Public Service Commission), or is owned by a governmental unit or the consumers that the entity serves. According to the Department of Energy (DOE)'s Energy Information Administration (EIA), plants that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act are not considered electric utilities [U.S. DOE, 2012b].
- *Non-Industrial Non-Utility*: Any entity that generates, transmits, and/or sells electricity, or sells or trades electricity services and products, where costs are not established and recovered by a regulatory authority. Non-utility power producers include, but are not limited to, independent power producers, power marketers and aggregators, merchant transmission service providers, self-generation entities, and cogeneration firms with Qualifying Facility Status [U.S. DOE, 2012b]. Like utilities, the primary purpose of non-industrial non-utilities is producing electric power for distribution and/or sale.
- *Industrial Non-Utility*: Industrial non-utilities are similar to non-industrial non-utilities except their primary purpose is not distributing and/or selling electricity. This category includes electric generators that are located at industrial plants such as chemical manufacturing plants or paper mills. Industrial non-utilities typically provide most of the electrical power they generate to the industrial operation with which they are located, although they may also provide some electric power to the grid for distribution and/or sale.

This section presents available demographic data and other information for the electric generating industry, excluding industrial non-utilities. EPA analyzed the available demographic information using EIA data for the year 2009 (Form EIA-860) [U.S. DOE, 2009] and U.S. Census Bureau data collected in the 2007 Economic Census [USCB, 2007]. EPA used the 2009 EIA data because data collected from the steam electric industry via EPA's *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (survey) represents plant-level operations in 2009 and the 2007 Census data because, as a 5-year census, it is the most recent year for which data are available. Together, these sources provide the most recent and comprehensive set of power plant data available. EPA identified electric generating plants in the EIA database as those reporting North American Industrial Classification System (NAICS) code 22 – Utilities.[11] The 2007 Economic Census data include more specific industry sector information at the six-digit NAICS code level.

[11] NAICS code 22 – *Utilities* is defined as establishments providing the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Excluded from this sector are establishments primarily engaged in waste management services [USCB, 2007].

EPA also examined the data on operations that electric generating plants reported to the EIA in 2009. Form EIA-860 contains records for 15,169 steam and nonsteam electric generating units having at least one megawatt (MW) of capacity operated at 5,300 facilities for calendar year 2009 [U.S. DOE, 2009]. Because the EIA data also include units at industrial non-utilities, they overestimate the number of units and plants that may be considered part of the electric generating industry.

According to the Economic Census, there were 1,934 electric generating plants in the United States in 2007, 69 percent (1,327 plants) of which were characterized primarily as using fossil or nuclear fuel [USCB, 2007]. These data include both steam and non-steam-electric generating processes. Table 4-1 presents the distribution of plants among each of the electric generating NAICS codes. The Economic Census includes all facilities reporting under NAICS code 22. As a result, it includes entities categorized by DOE as utilities and non-industrial non-utilities, but does not include industrial non-utilities.

Table 4-1. Distribution of U.S. Electric Generating Plants by NAICS Code in 2007

NAICS Code – Description	Plants
221111 – Hydroelectric Power Generation	295
221112 – Fossil Fuel Electric Power Generation	1,248
221113 – Nuclear Electric Power Generation	79
221119 – Other Electric Power Generation (includes conversion of other forms of energy, such as solar, wind, or tidal power, into electrical energy)	312
22111 – Electric Power Generation (Total)	**1,934**

Source: U.S. Census, [USCB, 2007].

4.1.2 <u>Applicability of Steam Electric Power Generating Effluent Guidelines</u>

Industrial non-utilities are not included within the scope of the existing Steam Electric Power Generating ELGs because they are not primarily engaged in producing electricity for distribution and/or sale.[12] As described above, these industrial non-utilities typically are industrial plants that produce, process, or assemble goods, and the electricity generated at these plants is an ancillary operation used to dispose of a by-product or for cost savings.

Because industrial non-utilities are not included in the applicability of the Steam Electric Power Generating ELGs, EPA has excluded them from the discussion of the U.S. electric generating industry for the purposes of this document. Therefore, information presented on plants composing the electric generating industry includes only the utilities and the non-industrial non-utilities. Although the transmission and distribution entities are included in the definition of utilities and non-industrial non-utilities, they are not included in the Steam Electric

[12] The applicability of the Steam Electric Power Generating Point Source Category (40 CFR 423.10) states the following: "The provisions of this part are applicable to discharges resulting from the operation of a generating unit by an establishment primarily engaged in the generation of electricity for distribution and sale which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium."

Category; therefore, this document presents information only on the plants and NAICS codes associated with the generation of electricity.

As shown in Figure 4-1, the electric generating industry can be further broken down based on the type of prime mover used to generate electricity. EIA defines a prime mover as the engine, turbine, water wheel, or similar machine that drives an electric generator or a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)) [U.S. DOE, 2012a]. Because the Steam Electric Power Generating ELGs are applicable only to plants generating electricity using a "thermal cycle employing the steam water system as a thermodynamic medium," EPA categorized the prime movers into "steam electric" and "non-steam-electric" categories. The steam electric generating units include steam turbines and combined cycle systems (see Sections 4.2.1 and 4.2.2 for more details on these types of units). The non-steam-electric generating units include, but are not limited to, stand-alone combustion turbines, internal combustion engines, fuel cells, and wind turbines.

The final criterion for a plant to meet the applicability of the Steam Electric Power Generating ELGs is that it must primarily utilize a fossil or nuclear fuel to generate the steam used in the turbine. Fossil fuels include coal, oil, or gas, and fuels derived from coal, oil, or gas such as petroleum coke, residual fuel oil, and distillate fuel oil. Fossil fuels also include blast furnace gas and the product of gasification processes using fossil-based feedstocks such as coal, petroleum coke, and oil. Examples of nonfossil/nonnuclear fuels used by some steam electric power plants include pulp mill black liquor, municipal solid waste, and wood solid waste.

4.2 STEAM ELECTRIC GENERATING INDUSTRY

EPA identified the subset of electric generating plants in the EIA database that use steam electric processes as those operating at least one prime mover that utilizes steam. The following electric generating unit or prime mover types specified in the EIA database are included in the steam electric industry:

- Steam turbine;
- Combined cycle system – steam turbine portion; and
- Combined cycle system – combustion turbine portion.[13]

Within each prime mover category, electric generating units are also classified by type of unit based on how often the units are in operation. Units can be classified as baseload, peaking, cycling, or intermediate. Baseload units produce electricity at an essentially constant rate and typically run for extended periods, peaking units operate during peak-load periods, cycling units generally operate in a routine cycle (i.e., only operating during the day), and intermediate units produce electricity on an as needed basis operating more frequently than peaking units but less frequently than baseload units.

[13] Although the combustion turbine portion of the combined cycle system does not use steam to turn the turbine, the combined cycle system does use steam associated with the steam turbine portion; therefore, both portions are included in the analysis because the entire combined cycle system is covered under the Steam Electric Power Generating ELGs.

The subset of steam electric power plants that are regulated by the Steam Electric Power Generating ELGs use a fossil or nuclear fuel as the primary energy source for the steam electric generating unit. In analyzing the EIA data, EPA included plants using the following EIA-defined nuclear and fossil (or fossil-derived) fuel types:

- Anthracite coal;
- Bituminous coal;
- Lignite coal;
- Subbituminous coal;
- Coal synfuel;
- Waste/other coal;
- Petroleum coke;
- No. 1 Fuel Oil;
- No. 2 Fuel Oil;
- No. 4 Fuel Oil;
- No. 5 Fuel Oil;
- No. 6 Fuel Oil;
- Diesel Fuel;
- Jet fuel;
- Kerosene;
- Oil-other and waste oil (e.g., crude oil, liquid by-products, oil waste, propane (liquid), rerefined motor oil, sludge oil, tar oil);
- Natural gas;
- Blast furnace gas;
- Gaseous propane;
- Other gas; and
- Nuclear (e.g., uranium, plutonium, thorium).

Using the criteria for the prime mover type and energy source described above for all plants (utilities and non-industrial non-utilities) reporting a NAICS code of 22 to EIA in 2009, EPA identified 1,179 steam electric power plants potentially subject to the Steam Electric Power Generating ELGs. In analyzing the EIA energy source data for the purpose of this report, EPA limited the analysis to identify only plants/units that reported one of the above energy sources as a "primary" or "secondary" energy source in the 2009 EIA data.[14] The 1,179 plants operate an

[14] For the purposes of this analysis, EPA included only plants/units based on the "secondary" energy source when it was reported as a type of coal or petroleum coke. For example, if a generating unit reported the "primary" energy source as municipal solid waste and the "secondary" energy source as coal, the plant was included in the analysis; however, if the generating unit reported the "secondary" energy source as natural gas, then the plant would not have been included in the analysis.

estimated 3,341 stand-alone steam electric generating units or combined cycle systems, which have a total generating capacity of 778,000 MW [U.S. DOE, 2009].

4.2.1 Steam Electric Generating Process

Steam electric power plants generate electricity using a process that includes a steam generator (i.e., boiler), a steam turbine/electrical generator, and a condenser. Figure 4-2 illustrates the stand-alone steam electric process, in which a combustible fuel is used as the energy source to generate steam. The Steam Electric Power Generating ELGs regulate wastewater discharged by those steam electric power plants that use fossil-type fuel (e.g., coal, oil, or gas) or nuclear fuel to generate the steam. As shown in Figure 4-2, fuels are fed to a boiler where they are combusted to generate steam. Boilers and their associated subsystems often include components to improve thermodynamic efficiency by boosting steam temperature and preheating intake air using superheaters, reheaters, economizers, and air heaters. The hot gases from combustion (i.e., the flue gas) leave the steam generator subsystem and pass through particulate collection and the sulfur dioxide (SO_2) scrubbing system (if present), and then are emitted through the stack. Natural gas-fired units typically do not operate these types of air pollution controls. The high-temperature, high-pressure steam leaves the boiler and enters the turbine generator where it drives the turbine blades as it moves from the high-pressure to the low-pressure stages of the turbine. The spinning of the turbine blades drives the linked generator, producing electricity. The lower-pressure steam leaving the turbine enters the condenser, where it is cooled and condensed by the cooling water flowing through heat exchanger (condenser) tubes. The water collected in the condenser (condensate) is returned to the boiler where it is again converted to steam [Babcock & Wilcox, 2005].

Combusting coal, petroleum coke, and oil in steam electric boilers produces a residue of noncombustible fuel constituents, referred to as ash. Some of the ash consists of very fine particles that are light enough to be entrained in the flue gas and carried out of the furnace and is commonly known as fly ash. The heavier ash that settles in the furnace or is dislodged from furnace walls is collected at the bottom of the boiler and is referred to as bottom ash.

Combusting fossil fuels also generates pollutants in the flue gas (e.g., nitrogen oxides, SO_2, carbon dioxide (CO_2)) that, if not removed, would be emitted to the atmosphere. Therefore, many plants operate air pollution control technologies that remove these pollutants from the flue gas. The following are some of the common air pollution control technologies used in the industry and the pollutant they are primarily used to control:

- Electrostatic precipitator (ESP): fly ash/particulate matter;
- Flue gas desulfurization (FGD): SO_2;
- Selective catalytic reduction (SCR): nitrogen oxides;
- Selective non-catalytic reduction (SNCR): nitrogen oxides; and
- Flue gas mercury controls (FGMC): mercury.

The nuclear-fueled steam electric process is similar to the steam/water system described above. The nuclear system differs from the non-nuclear system in three key ways: fuel handling, nuclear fission within the reactor core instead of the boiler as the heat source for producing steam, and no air pollution control equipment. No fuel is combusted and no ash is generated in a nuclear-fueled steam electric process. Instead, heat transferred from the reactor core creates steam in boiling water reactors or creates superheated water in pressurized-water reactors. The steam turbine/electric generator and condenser portions of the nuclear-fueled steam electric process are the same as those described for the stand-alone steam electric process [U.S. DOE, 2012c].

4.2.2 Combined Cycle Systems

Some steam electric power plants operate one or more combined cycle systems fueled by fossil or fossil-type fuels to produce electricity. A combined cycle system comprises one or more combustion turbine electric generating units operating in conjunction with one or more steam turbine electric generating units. Combustion turbines, which typically are similar to jet engines, commonly use natural gas as the fuel, but may also use oil. Exhaust gases from combustion are sent directly through the combustion turbine, which is connected to a generator to produce electricity. The exhaust gases exiting the combustion turbine still contain useful waste heat, so they are directed to heat recovery steam generators (HRSGs) to generate steam to drive an additional turbine. The steam turbine is also connected to a generator (which may be a different generator or the same generator that is connected to a combustion turbine) that produces additional electricity. Thus, combined cycle systems use steam turbine technology to increase the efficiency of the combustion turbines. Figure 4-3 illustrates the combined cycle system process.

Steam electric units within combined cycle systems operate almost identically to stand-alone steam electric units, except without the boiler. In a combined cycle system, the combustion turbines and HRSGs functionally take the place of the boiler of a stand-alone steam electric unit. The other two major components of steam electric generating units within combined cycle systems, the steam turbine/electric generator and steam condenser, are virtually identical to those of stand-alone steam electric units. Thus, the wastewaters and pollutants generated from both types of systems are the same. However, the wastewaters of the combined cycle units are more closely associated with gas-fired steam electric units, and therefore do not typically generate ash or FGD wastewaters. The wastewaters generated from combined cycle units typically include cooling water, boiler blowdown, metal cleaning wastes, and steam condensate water treatment wastes.

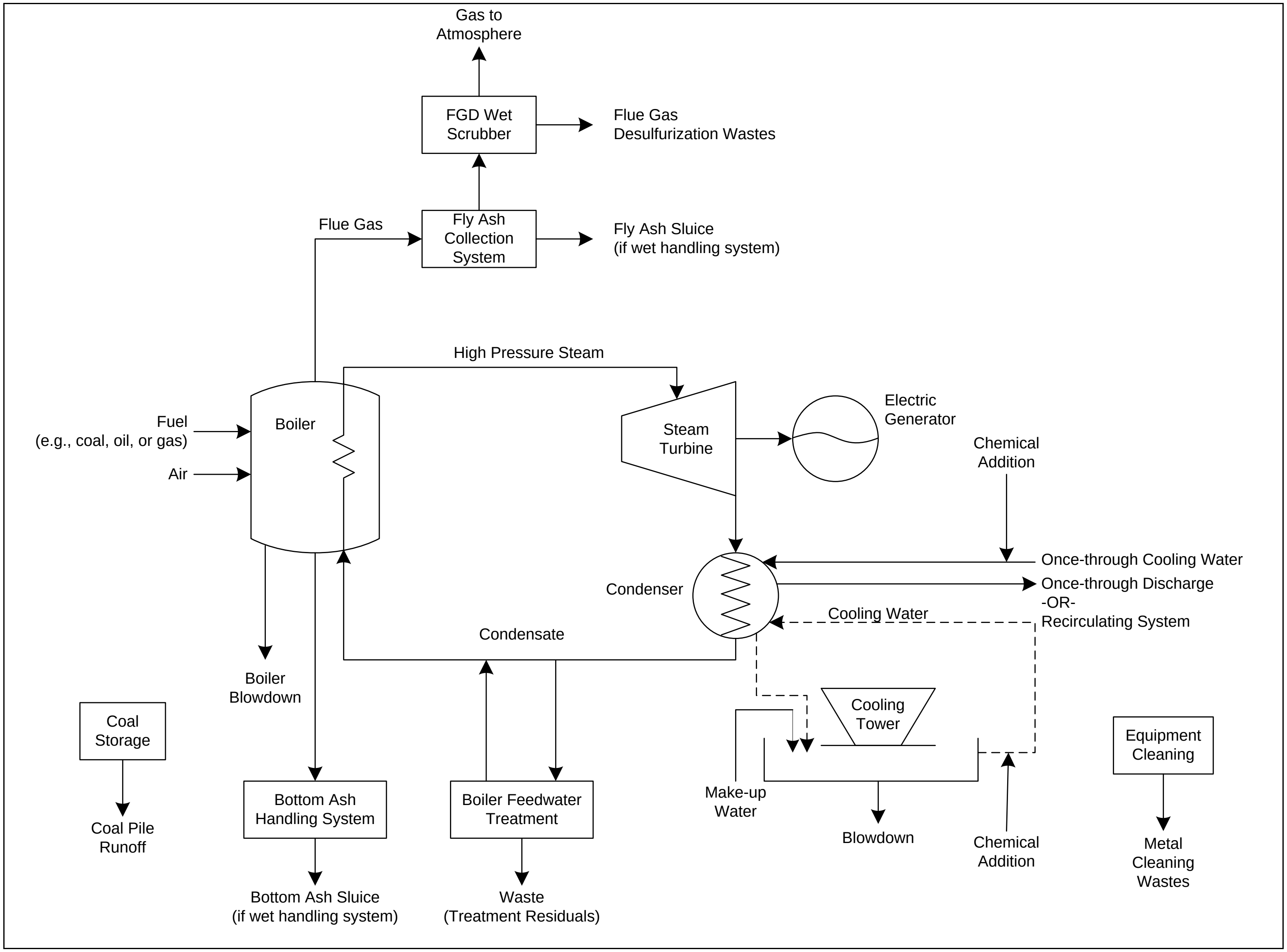


Figure 4-2. Steam Electric Process Flow Diagram

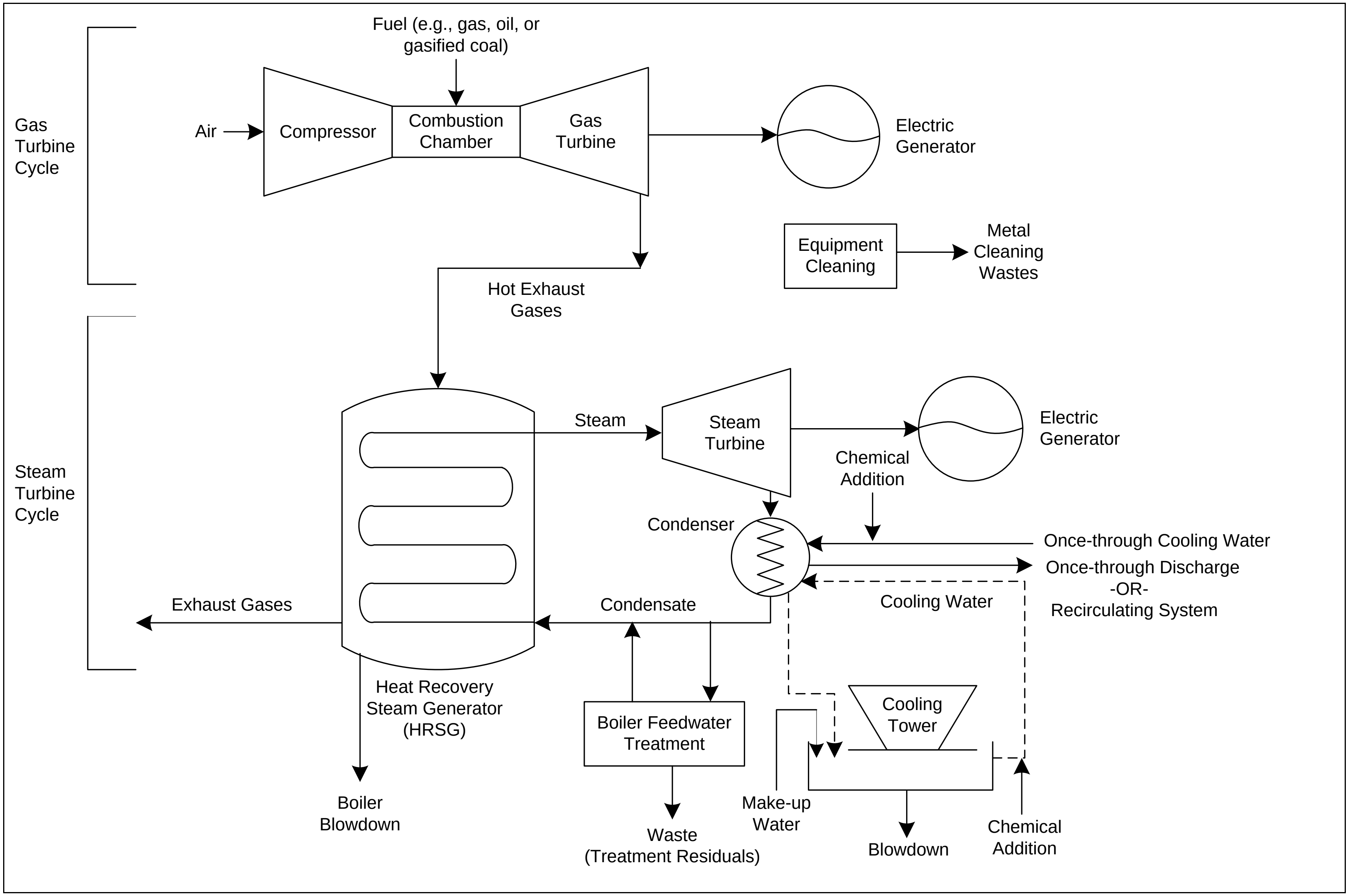


Figure 4-3. Combined Cycle Process Flow Diagram

4.2.3 Integrated Gasification Combined Cycle Systems

Integrated gasification combined cycle (IGCC) systems combine gasification technology with both gas turbine and steam turbine power generation (i.e., combined cycle power generation). In an IGCC system, a gasifier converts carbon-based feedstock (e.g., coal or petroleum coke) into a synthetic gas ("syngas"). The syngas is cleaned of particulates, sulfur, and other contaminants and is then combusted in a high-efficiency combustion gas turbine/generator. An HRSG then extracts heat from the combustion turbine exhaust to produce steam and drive a steam turbine/generator. IGCC plants can achieve higher thermodynamic efficiencies, emit lower levels of criteria air pollutants, and consume less water per MW than traditional coal combustion power plants. Like typical combustion power plants, solid wastes and wastewater are generated from the gasification process.

DOE's National Energy Technology Laboratory (NETL) Gasification World Database reports two commercial-scale IGCC systems located in the United States -- the 262-MW Wabash River IGCC Repowering Project (Wabash River) in Indiana and the 250-MW Tampa Electric Polk Power Station IGCC Project (Polk) in Florida. Other U.S. power companies are investigating or planning IGCC systems at new or existing plants, such as Duke Energy's Edwardsport Station in Knox County, Indiana, which has an IGCC unit under construction that was expected to begin commercial operation sometime in 2012 [Duke Energy, 2012].

EPA has conducted site visits at each of the three plants identified above. Figure 4-4 presents a general process flow diagram for an IGCC system. The specific gas preparation and by-product recovery operations at the plants may vary, but each uses the same general electric generating process. For example, Polk operates a sulfuric acid plant to recover sulfur, while Wabash River uses the Claus process to generate an elemental sulfur product [ERG, 2009c; ERG, 2011].

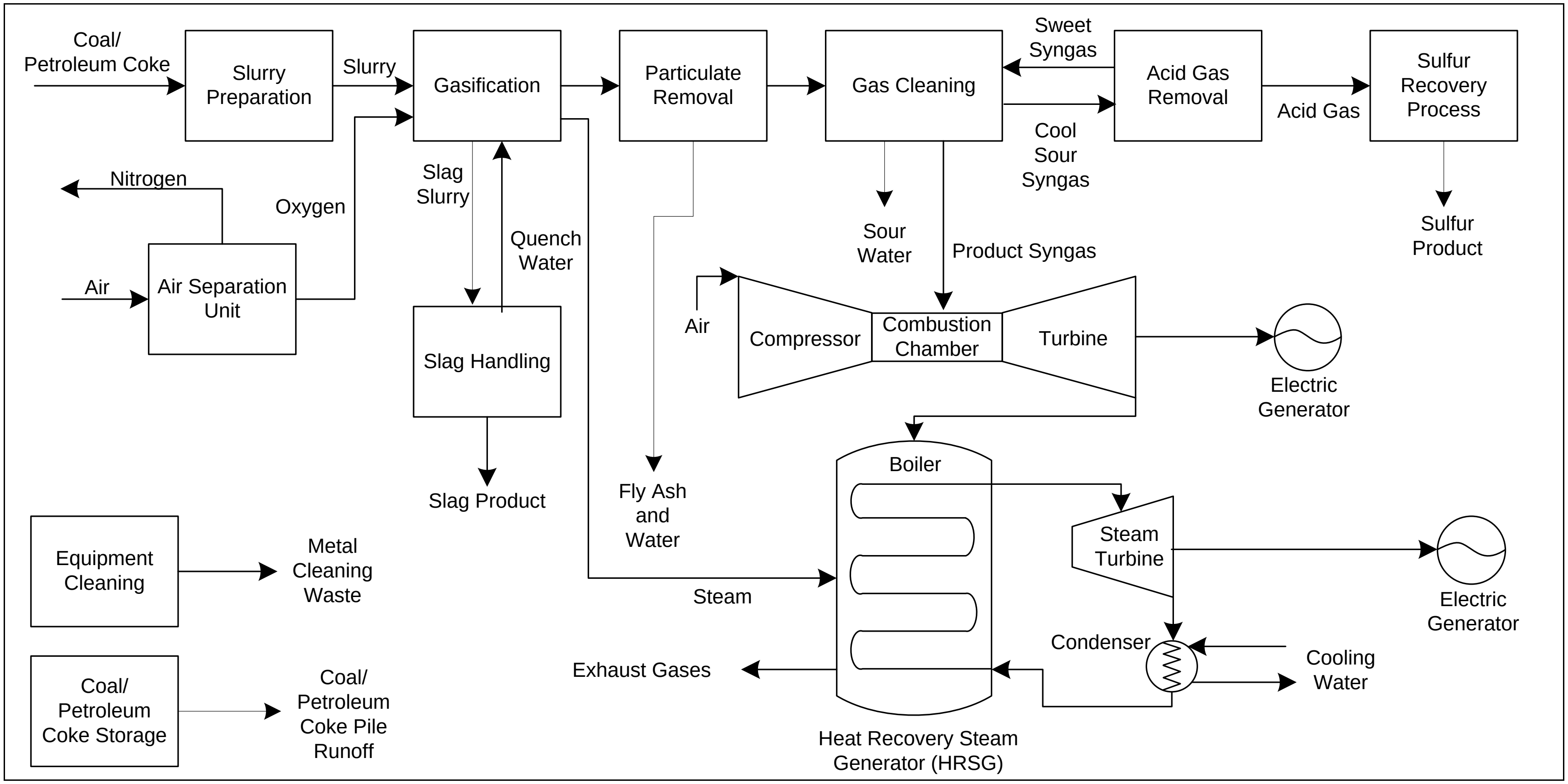


Figure 4-4. IGCC Process Flow Diagram

4.2.4 Demographics of the Steam Electric Power Generating Industry

In 2010, EPA's Office of Water administered the Steam Electric Information Collection Request (ICR) (Steam Electric Survey) to power plants believed to be subject to the Steam Electric Power Generating ELGs. As described in Section 3.3, EPA distributed the survey to all coal- and petroleum-coke fired plants identified in the 2007 EIA and a statistically sampled subset of steam electric power plants burning other types of fuel, including oil-fired, gas-fired, and nuclear power plants. EPA obtained information on specific aspects of power plant operation for the 2009 calendar year.[15] The survey also requested information about planned steam electric generating units, treatment systems, and other improvements or modifications through the year 2020. EPA uses data from the Steam Electric Survey throughout this report to describe the current state of the steam electric industry and to make predictions on the general direction of the industry in the near future. This section presents demographic data and other information to characterize the steam electric industry based on data obtained through the 2009 EIA and EPA's Steam Electric Survey.

Table 4-2 presents the distribution of the types of steam electric prime movers used by plants subject to the Steam Electric Power Generating ELGs using both the 2009 EIA data and EPA's Steam Electric Survey. The table includes the numbers of plants, electric generating units, and capacity for each type of steam electric prime mover. The number of electric generating units represents the number of generators/turbines used to generate electricity and does not necessarily relate to the number of boilers. The number of plants, units, and capacity in the steam electric industry generated from the Steam Electric Survey are based on values reported in the survey, which were scaled up to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

As shown in Table 4-2, the Steam Electric Survey estimates are lower than the 2009 EIA data estimates. Based on EIA data, the industry had 1,179 plants operating at least one steam electric generating unit powered by a fossil or nuclear fuel in 2009. The weighted survey data indicate that the industry had 1,079 plants operating at least one steam electric generating unit in 2009.[16] As described in Section 3.3, the survey captured data from plants identified using 2007 EIA data but responses reflect data for the 2009 production year. The steam electric industry is dynamic; the discrepancies between survey data and the 2009 EIA could be due to new installations, unit fuel conversions, plant/unit retirements. In addition, the Steam Electric Power Generating ELGs are not applicable to all units generating electricity. Units that do not burn fossil fuels or plants with a primary purpose other than generating electricity do not fall under the applicability of the Steam Electric ELGs. Therefore, EPA used the weighted survey results for the remainder of the analyses in this document to represent the steam electric industry in 2009.

[15] EPA is using January 1, 2014 as the baseline for the proposed ELG because 2014 is the year that EPA expects to promulgate the final rule. The data presented in this section represent 2009 conditions, unless otherwise noted, because the data are based on responses collected from the Steam Electric Survey.

[16] The weighted survey initially indicated that there were 1,088 power plants operating at least one steam electric generating unit powered by a fossil or nuclear fuel. However, upon further inspection, the data indicated that only 1,079 of these plants operated at least one steam electric generating unit in 2009.

Based on the Steam Electric Survey data, the majority (66 percent) of the steam electric power produced by the plants subject to the ELGs is generated using stand-alone steam turbines, which are also the most prevalent type of steam electric prime mover used. Table 4-3 presents the distribution of fossil and nuclear fuels used to power each type of steam electric prime mover. The number of electric generating units represents the number of generators/turbines used to generate electricity and is not equal to the number of boilers. The vast majority (93 percent) of these generating units burn at least some amount of either coal or gas. Coal is the most common primary fuel type for stand-alone steam turbines, while gas is the primary fuel for nearly all combined cycle systems. Oil-fired units are not very prevalent in the industry, accounting for roughly only 3 to 4 percent of the total number of generating units and capacity.

Table 4-4 presents the steam electric capacity, as well as the number of steam electric power plants distributed by *overall plant capacity.*[17] Table 4-4 includes the stand-alone steam turbines and all the combined cycle system turbines (i.e., combined cycle steam turbine, combined cycle single shaft, and combined cycle combustion turbine) in the number of steam electric power plants and steam electric capacity. According to the weighted Steam Electric Survey data, the largest capacity plants (>500 MW) comprise over 60 percent of all steam electric power plants and 90 percent of the steam electric generating capacity for all plants regulated by the ELGs. Based on the weighted Steam Electric Survey data, most steam electric power plants are either gas- or coal-fired and have a generating capacity greater than 500 MW.

Table 4-5 presents the steam electric industry broken out by size of the generating units. Table 4-5 includes the stand-alone steam turbines and the all the combined cycle steam turbines. To determine the size of the combined cycle generating units, EPA added the capacity for all combined cycle turbines (i.e., combined cycle steam turbine, combined cycle single shaft, and combined cycle combustion turbine) for each turbine identified for the specific generating unit. There are 281 generating units with a capacity of 50 MW or less (13 percent of all steam electric generating units); however, only 71 coal- or petroleum coke-fired generating units have a capacity of 50 MW or less (3.2 percent of all coal- or petroleum coke-fired generating units). The 281 generating units account for only 1.1 percent of the total capacity associated with the steam electric industry.

Stand-alone steam turbines are more prevalent than combined cycle units within the steam electric industry. These stand-alone steam turbines are generally larger units, with 70 percent having a capacity of 500 MW or greater. In most cases, stand-alone steam turbines will burn coal- or petroleum-coke as either a primary or a secondary fuel. Of the total steam electric capacity, stand-alone steam turbines burning coal or petroleum coke account for 70 percent.

[17] The overall plant capacity includes all electric power generated by the plant, including electricity produced using non-steam generators and through the use of non-fossil/non-nuclear energy sources.

Table 4-2. Distribution of Prime Mover Types for Plants Regulated by the Steam Electric Power Generating Effluent Guidelines

	2009 EIA			Steam Electric Survey		
Steam Electric Prime Movers	**Number of Plants [a]**	**Number of Electric Generating Units**	**Total Steam or Combined Cycle Turbine Capacity (MW)**	**Number of Plants [a]**	**Number of Electric Generating Units**	**Total Steam or Combined Cycle Turbine Capacity (MW)**
Stand-Alone Steam Turbine	787 (67%)	1,868 (76%)	555,000 (71%)	716 (66%)	1,640[b] (74%)	528,000 (71%)
Combined Cycle Systems [c]	438 (37%)	599 (24%)	224,000 (29%)	408 (38%)	573 (26%)	213,000 (29%)
Combined Cycle Steam Turbine [d]	416	550	81,100	408	573	87,700[g]
Combined Cycle Single Shaft (steam and combustion turbines shaft as single shaft) [e]	22	49	9,570	-	-	-
Combined Cycle Combustion Turbine	411	1,013	134,000	404	570	125,000[g]
Total	**1,179 (100%)**	**2,467[f] (100%)**	**780,000 (100%)**	**1,079 (100%)**	**2,214[f] (100%)**	**741,000 (100%)**

Source: Steam Electric Survey, [ERG, 2013]; 2009 EIA, [U.S. DOE, 2009].

Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric industry generated from the Steam Electric Survey are based on values reported in the survey, which were scaled up to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – Because a single plant may operate multiple electric generating units of various prime mover types, the number of plants by prime mover type is not additive. There are 1,179 plants (according to the 2009 EIA) or 1,079 plants (according to the steam electric survey) in the industry that operate at least one steam electric generating unit powered by either fossil or nuclear fuel.

b - One generating unit operating a stand-alone steam turbine was reported as burning only wood. This unit is not included in the count of generating units because it does not meet the applicability of the steam electric ELGs.

c – Due to the nature of the EIA data, EPA was able to identify the number of combined cycle turbines (i.e., prime movers), but could not discern the number of actual combined cycle systems. EPA estimated the number of combined cycle systems reported in EIA by adding the number of combined cycle steam turbines and the number of single shaft turbines. Typically, there are multiple combustion turbines to a single steam turbine in a combined cycle system; therefore, EPA believes this methodology better represents the number of combined cycle systems than simply adding the number of combined cycle combustion and steam turbines. For the Steam Electric Survey data, the plants reported the combined-cycle-system-level information directly.

d – One plant in the 2009 EIA database reported using a fossil fuel for its combined cycle steam turbine and a non-fossil/non-nuclear fuel for its three combined cycle combustion turbines. EPA included the combined cycle steam turbine from this plant in the table, but did not include the combined cycle combustion turbines using fuels not covered by the ELGs.

e – EIA data differentiate among types of combined cycle turbines, with a separate designation for single shaft turbines (steam and combustion turbines sharing a single shaft). EPA's Steam Electric Survey does not differentiate between types of combined cycle systems; single shaft turbines are included as combined cycle systems in the survey.

f – EPA estimated the total number of electric generating units as the sum of the stand-alone steam turbines and the estimated number of combined cycle systems. EPA did not sum the total number of turbines.

g – From the survey data, EPA was not able to categorize the combined cycle systems as a combined cycle steam turbine, a combined cycle single shaft, or a combined cycle combustion turbine. Seven plants (17 units) identified operating a combined cycle system but provided only the steam turbine capacity. The 2009 EIA data identifies these units as single-shaft turbines. The total capacity of these units, steam turbine and combustion turbine capacity, is accounted for under combined cycle steam turbines.

Table 4-3. Distribution of Fuel Types Used by Steam Electric Generating Units

Fossil or Nuclear Fuel [a]	Stand-Alone Steam Turbines			Combined Cycle Steam Turbines [b]		
	Number of Plants	Number of Electric Generating Units	Total Turbine Capacity (MW)	Number of Plants	Number of Electric Generating Units	Total Turbine Capacity (MW)
Coal:	*455-465*	*1,080-1,090*	*328,000-330,000*	*2*	*2*	*427*
Anthracite Coal	1	1	128	0	0	0
Bituminous Coal	209	497	144,000	1	1	101
Subbituminous Coal	145	310	109,000	0	0	0
Lignite Coal	10-15	10-20	7,000-8,000	0	0	0
Coal Synfuel	0	0	0	0	0	0
Waste/Other Coal	17	18	1,660	0	0	0
Blend [c]	106	240	66,700	1	1	326
Petroleum Coke	*8*	*11*	*751*	*1*	*1*	*334*
Oil:	*55-65*	*70-85*	*22,500-23,500*	*5-10*	*5-15*	*1,400-1,900*
No. 1 Fuel Oil	0	0	0	0	0	0
No. 2 Fuel Oil	1-5	1-5	200-300	0	0	0
No. 4 Fuel Oil	1	1	210	0	0	0
No. 5 Fuel Oil	0	0	0	0	0	0
No. 6 Fuel Oil	15-20	20-30	12,500-13,500	0	0	0
Diesel Fuel	3	3	1,480	4	7	438
Jet Fuel	0	0	0	0	0	0
Kerosene	0	0	0	1-5	1-5	1,000-1,500
Waste Oil/Other Oil	0	0	0	0	0	0
Blend [c]	32	46	8,430	0	0	0
Gas:	*171*	*367*	*71,500*	*400*	*562*	*210,000*
Natural Gas	171	367	71,500	395	556	210,000
Blast Furnace Gas	0	0	0	0	0	0
Gaseous Propane	0	0	0	0	0	0
Other Gases	0	0	0	0	0	0
Blend [c]	0	0	0	5	5	537

Table 4-3. Distribution of Fuel Types Used by Steam Electric Generating Units

Fossil or Nuclear Fuel [a]	Stand-Alone Steam Turbines			Combined Cycle Steam Turbines [b]		
	Number of Plants	Number of Electric Generating Units	Total Turbine Capacity (MW)	Number of Plants	Number of Electric Generating Units	Total Turbine Capacity (MW)
Nuclear	*66*	*99*	*104,000*	*0*	*0*	*0*
Total	**716 [d]**	**1,640**	**528,000**	**408 [d]**	**573**	**213,000**

Source: Steam Electric Survey [ERG, 2013].

Note: Certain cells contain ranges of values to protect the release of information claimed confidential business information (CBI).

Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric industry generated from the Steam Electric Survey are based on values reported in the survey, which were scaled up to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – Units were first classified by fuel group based on the following hierarchy: coal, oil, gas, and nuclear. For example, if a unit burns both coal and gas then it was categorized as coal, even if coal was reported as generating less electricity compared to other fuel groups. Units were then categorized by the type of fuel burned.

b – The Steam Electric Survey identifies combined cycle systems, which include at least one steam turbine and one combustion turbine.

c – The 'blend' category identifies units that burn more than one type of fuel within the fuel group. For example, for a generating unit that burns coal, a blend coal unit burns at least two different types of coal.

d – Because a single plant may operate multiple electric generating units burning various types of fuel, the number of plants by fuel type is not additive. There are 716 plants responding to the survey that operate at least one stand-alone steam turbine powered by either fossil or nuclear fuel. There are 408 plants responding to the survey that operate at least one combined-cycle system powered by either fossil or nuclear fuel.

Table 4-4. Distribution by Size of Steam Electric Capacity and Plants Regulated by the Steam Electric Power Generating Effluent Guidelines

	Overall Plant Capacity Range[a]						Total
	0-100 MW	100-200 MW	200-300 MW	300-400 MW	400-500 MW	>500 MW	
Total Steam Electric Capacity (MW) [b]	5,040	9,410	11,300	17,600	17,100	680,000	741,000
Percentage of Capacity	0.7%	1.3%	1.5%	2.4%	2.3%	91.8%	100%
Number of Plants	103	88	72	79	61	676	1,079
Percentage of Plants	9.6%	8.2%	6.6%	7.3%	5.7%	62.7%	100%

Source: Steam Electric Survey, [ERG, 2013].

Note: Capacity values are rounded to three significant figures.

Note: The number of plants and total steam electric capacity includes the stand-alone turbines and the combined cycle systems.

Note: The number of plants and capacity in the steam electric industry are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – Overall plant steam electric capacity includes electricity produced by only steam electric generating units. Electricity generated by non-steam-electric electric units and those using non-fossil/non-nuclear energy sources is not included.

b – The capacity presented within each size distribution is based on the overall plant steam electric capacity.

Table 4-5. Distribution by Size of Steam Electric Generating Units Regulated by the Steam Electric Power Generating Effluent Guidelines

	Unit Capacity Range							Total
	0-50 MW	50-100 MW	100-200 MW	200-300 MW	300-400 MW	400-500 MW	>500 MW	
Total Steam Electric Capacity (MW) [a]	8,010	23,200	65,700	62,200	72,200	55,700	454,000	741,000
Percentage of Capacity	1.1%	3.1%	8.9%	8.4%	9.7%	7.5%	61.3%	100%
Number of Steam Electric Generating Units	281	305	445	247	207	124	605	2,214
Percentage of Steam Electric Generating Units	12.7%	13.8%	20.1%	11.2%	9.3%	5.6%	27.3%	100%

Source: Steam Electric Survey, [ERG, 2013].

Note: Capacity values are rounded to three significant figures.

Note: The number of plants, number of steam electric generating units, and total steam electric capacity include the stand-alone turbines and the combined cycle systems.

Note: The number of units and capacity in the steam electric industry are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – The capacity presented within each size distribution is based on the capacity at the unit level.

4.3 STEAM ELECTRIC WASTESTREAMS EVALUATED FOR NEW OR ADDITIONAL CONTROLS IN THE PROPOSED ELGS

This section describes the wastestreams generated by steam electric power plants for which EPA evaluated new or revised discharge requirements for the proposed ELGs. Section 4.4 discusses other wastestreams generated by the steam electric industry that EPA did not evaluate for new or revised discharge requirements in the proposed ELGs.

4.3.1 Fly Ash Transport Water

Depending on the boiler design, as much as 70 to 80 percent of the ash from a pulverized coal furnace consists of fly ash. Certain boiler designs, such as cyclone boilers, produce relatively small amounts of fly ash, approximately 20 to 30 percent. Many plants transport fly ash from the boiler using water as the motive force, known as sluicing. This section presents an overview of fly ash transport water generated by the steam electric industry.

As discussed in Section 4.2.1, flue gas contains entrained fly ash as it leaves the boiler. Steam electric units employ three main particulate collection methods to remove fly ash from the flue gas: electrostatic precipitators (ESPs), baghouses, and venturi-type wet scrubbers. Of the approximately 1,100 coal-, petroleum coke-, and oil-fired units collecting fly ash, 97 percent utilize one of these three collection methods. The remaining 3 percent identified some other type of particulate collection system. Table 4-6 presents the number of coal- , petroleum coke-, and oil-fired units utilizing each of these collection methods and each is described below.

Table 4-6. Fly Ash Collection Practices in the Steam Electric Industry

Fly Ash Collection Method	Number of Plants	Number of Coal- and Petroleum Coke-Fired Steam Electric Units	Number of Oil-Fired Steam Electric Units
ESP	335	816	5-10
Baghouse	143	220	0
Baghouse and ESP	5-15	10-15	2
Wet Scrubber	5-15	15-25	0
Other	20	12	9
Total	**508-528[a]**	**1,080-1,100[a]**	**26-31**

Source: Steam Electric Survey, [ERG, 2013].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: The number of plants, units, and capacity in the steam electric industry are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – 15 coal-fired generating units at 9 plants identified no fly ash collection method. These plant and unit values are included in the count of total plants and units collecting fly ash.

To remove the fly ash particles from the flue gas, many plants operate electrostatic precipitators (ESPs). ESPs use high voltage to generate an electrical charge on the particles contained in the flue gas. The charged particles then collect on a metal plate with an opposite electric charge. Additionally, some plants may use agglomerating agents, such as ammonia, which help small charged ash particles form larger agglomerates that are more readily attracted to the charged plates, improving the removal efficiency of the ESPs. As the particles begin to layer on the metal plates, the plates are tapped/rapped to loosen the particles, which fall into collection hoppers. ESPs can remove 99.9 percent of fly ash from the flue gas [Babcock & Wilcox, 2005]. These types of systems are the most common type of fly ash collection system used in the steam electric industry. Of the approximately 1,100 coal-, petroleum coke-, and oil-fired units in the industry collecting fly ash in the steam electric survey, about 830 units (75 percent) utilize an ESP system [ERG, 2013].[18]

Plants may also use other particulate control technologies, such as baghouse filters. A baghouse system contains several compartments, each containing fabric filter bags that are suspended vertically in the compartment. The bags can be quite long (e.g., 40 feet) and small in diameter [Babcock & Wilcox, 2005]. The reverse air system is the baghouse configuration most commonly used by steam electric power plants. In this system, the flue gas enters into the various compartments and is forced to flow into the bottom of the fabric filter bags. The flue gas passes through the fabric filter, but the fly ash particulates cannot pass and are captured on the inside walls of the baghouse. As the baghouses collect more particulates, the layer of particulates becomes thicker and help to remove more particulates from the flue gas. After a specified period of time or once the pressure drop in the baghouse reaches a high set point, the plants reverse the flow in the compartments and send clean flue gas from the outside of the fabric filter bags to the inside, which dislodges the particulates. The particulates are captured in hoppers at the bottom of the compartment [Babcock & Wilcox, 2005]. Of the approximately 1,100 coal-, petroleum coke-, and oil-fired generating units that reported collecting fly ash from flue gas, about 235 units use baghouse filters (22 percent) [ERG, 2013].[19]

After the ESP or baghouse deposits the fly ash into the hoppers, the plant can either handle the fly ash in a dry or wet fashion. In either system, dry fly ash is initially drawn away from the hoppers using a vacuum to pneumatically transport the ash. Plants operating a dry fly ash handling system pneumatically transfer the fly ash from the hopper to a fly ash storage silo and then dispose of the ash. Plants operating a wet fly ash handling system use water as the motive force to transport the fly ash from the hopper to a surface impoundment. Section 7.2 discusses the different ash handling methods used in the steam electric industry in more detail.

Additionally, between fifteen and twenty-five generating units use venturi-type wet scrubbers to remove fly ash from the flue gas [ERG, 2013]. Venturi scrubbers contain a tube with flared ends and a constricted middle section. The flue gas enters from one of the flared ends and approaches the constricted section. A liquid slurry stream is added to the scrubber just prior to or at the constricted section. As the flue gas enters the constricted section, its pressure and velocity increases, which causes the gas and liquid slurry to mix. The greater the pressure drop in the scrubber, the better the mixing, and the better the reaction rate, which increases the particulate removal efficiency. However, venturi scrubbers must be operated at high pressure drops to remove the same level of particulates as ESPs, making their operation costs higher than

[18] This includes 10 to 15 generating units that use a combination system that incorporates an ESP and baghouse filters to remove particulates from the flue gas.

[19] This includes 10 to 15 generating units that use a combination system that incorporates an ESP and baghouse filters to remove particulates from the flue gas.

ESPs [Babcock & Wilcox, 2005; U.S. EPA, 2010]. Based on the proposed revisions to the specialized definitions, described in Section 2.2, EPA does not consider the ash collected by venture scrubbers as fly ash, and therefore, the water generated by these systems is not considered fly ash transport water.

Table 4-7 presents the fly ash handling practices used by plants operating coal-, petroleum coke-, and oil-fired generating units. Approximately one-fourth of the plants operating coal-fired generating units handle at least a portion of their fly ash with a wet sluicing system. A small percentage of oil-fired units, approximately 20 percent, also wet sluice fly ash. In most cases, plants manually remove the fly ash from these oil-fired units by methods such as scraping the ash out of the boiler. In general, oil-fired units produce much less fly ash than coal-fired units. For example, oil-fired units responding to the survey produced an average of just over 60 tons of fly ash per year per unit, compared to over 60,000 tons per year for an average coal-fired unit.

Table 4-7. Fly Ash Handling Practices in the Steam Electric Industry

Fly Ash Handling	Number of Plants	Coal- and Petroleum Coke-Fired Steam Electric Units		Oil-Fired Steam Electric Units	
		Number of Units	Capacity (MW)	Number of Units	Capacity (MW)
Wet-Sluiced	57 (11%)	205	47,000 (14%)	10-15	7,500-10,000 (33%)
Handled Dry or Removed in Scrubber [a]	344 (67%)	713	222,000 (67%)	10-15	2,500-5,000 (17%)
Handled Either Wet or Dry [b]	81 (16%)	168	59,000 (18%)	1-5	500-1,500 (3%)
No Handling System Reported	31 (6%)	10	2,370 (1%)	61	11,400 (44%)
Total	**514**	**1,096**	**330,000**	**80-95**	**21,900-27,900**

Source: Steam Electric Survey, [ERG, 2013].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

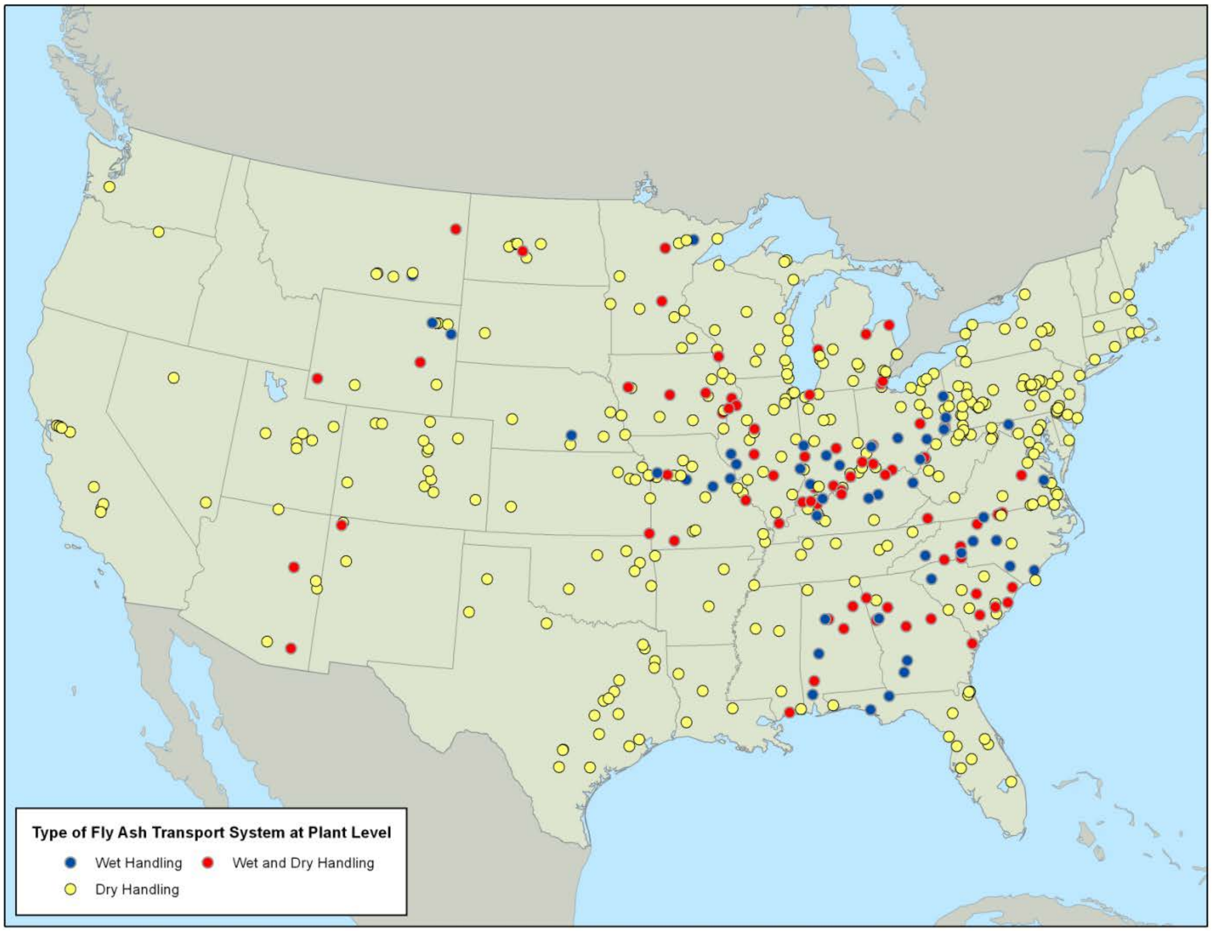
Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric industry are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – EPA considered all transport methods other than wet sluicing as dry fly ash transport.

b –These units have both wet and dry handling systems for removing fly ash from the boiler and can operate either system as needed.

Most plants operating wet fly ash handling systems are located east of the Mississippi River. Figure 4-5 provides a distribution of the three categories of fly ash handling practices presented in Table 4-7. Each symbol represents the plant-level fly ash handling system. The figure only includes the plants for which responses were provided in the Steam Electric Survey (i.e., the figure does not represent the weighted numbers). Plants categorized as ‘wet and dry handling’ operate some units at the plant with wet fly ash handling systems and other units at the plant with dry fly ash handling systems, or in some instances operate both a wet and a dry fly ash handling system for an individual generating unit.



Source: Steam Electric Survey, [ERG, 2013].

Figure 4-5. Plant-Level Fly Ash Handling Systems

In 1982, EPA promulgated new source performance standards (NSPS) that prohibited new sources from discharging wastewater pollutants in fly ash transport water. Not surprisingly, EPA has found that the steam electric units generating wet fly ash transport water tend to be older units (e.g., more than 30 years old), while most units built since the NSPS were promulgated are outfitted with dry fly ash handling systems.

EPA identified several plants that have installed dry fly ash handling systems, either to replace the preexisting wet handling system or to operate as a parallel system. Table 4-8 presents the number of units converted from wet fly ash handling to dry fly ash handling since 2000. Each plant and unit is classified by the type of dry system installed, which include wet vacuum pneumatic systems, dry vacuum systems, pressure systems, and combined vacuum and pressure systems. Each of these dry fly ash handling systems is described in Section 7. Data from the Steam Electric Survey show that power companies converted at least 115 units at over 45 plants to dry fly ash handling systems since 2000. Power companies also reported that they are planning to convert an additional 61 units to dry handling systems by the year 2020. The reasons cited for installing the dry handling systems include environmental remediation (i.e., discharges from the fly ash impoundments caused environmental impacts), economic opportunity (e.g., revenues from sale of fly ash), and the need to replace ash impoundments approaching full storage capacity. Because dry fly ash handling practices do not generate fly ash transport water, converting to a dry system eliminates the discharge of fly ash transport water and the pollutants contained therein. In addition, it reduces the amount of intake water the plant uses and eliminates the need for an impoundment to store the fly ash transport water. Section 6.2 presents additional information on the amount of fly ash transport water generated and discharged by the steam electric industry and the pollutant characteristics of the transport water.

Table 4-8. Conversions of Wet Fly Ash Sluicing Systems Since 2000

Type of Dry Fly Ash Handling System Installed	Number of Plants	Number of Units	Capacity (MW)
Wet Vacuum System (pneumatic) [a]	1-5	1-5	2,000-3,000
Dry Vacuum System [b]	24	50	9,400
Pressure System [c]	5-10	15-25	7,500-10,000
Combined Vacuum/Pressure System [d]	18	36	15,800
Total [e]	**45 – 55 (35 – 42%)**	**85 – 115 (26 – 35%)**	**34,700 – 38,200 (38-42%)**

Source: Steam Electric Survey, [ERG, 2013].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric industry are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

Note: Approximately 33 of these units also wet sluiced a portion of the fly ash in 2009.

a – One of these units also wet sluiced a portion of the fly ash in 2009.

b – Twelve of these units also wet sluiced a portion of the fly ash in 2009.

c – Four of these units also wet sluiced a portion of the fly ash in 2009.

d – Sixteen of these units also wet sluiced a portion of the fly ash in 2009.

e – The percentages are based on the number of systems conducting any wet sluicing operations (wet sluicing systems and wet and dry systems) in 2000 prior to any conversions (excluding units that have retired since that time).

4.3.2 Bottom Ash Transport Water

As much as 70 to 80 percent of the ash from a pulverized coal furnace consists of fly ash. The remaining 20 to 30 percent is bottom ash. Cyclone boilers, and other boiler designs, can produce a larger percentage of bottom ash, upwards of 70 to 80 percent. Like fly ash, bottom ash can be transported from the boiler using water. This section presents an overview of bottom ash transport water generated by the steam electric industry.

Heavy bottom ash particles collect in the bottom of the boiler. The sloped walls and opening at the bottom of the boiler allow the bottom ash to feed by gravity to the bottom ash hoppers positioned below the boiler. The bottom ash hoppers are connected directly to the boiler bottom to prevent any boiler gases from leaving the boiler. Depending on the size of the boiler, there may be more than one bottom ash hopper running along the opening of the bottom of the boiler. Most bottom ash hoppers are filled with water to quench the hot bottom ash as it enters the hopper. Once the bottom ash hoppers have filled with bottom ash, a gate at the bottom of the hopper opens and the ash is directed to grinders to grind the bottom ash into smaller pieces. From the hopper, bottom ash can be handled in a wet or dry fashion.

Plants operating a wet bottom ash handling system sluice the ground ash with water to an impoundment or a dewatering bin. Because bottom ash particles are heavier than fly ash particles, they more easily separate from the sluice water. Some plants operate large surface impoundments for bottom ash, while others use a system of relatively small impoundments operating in series and/or parallel. Other plants operate dewatering bin systems, in which they use a tank-based settling operation to separate the bottom ash solids from the transport water. A dewatering bin system generally consists of at least two bins; while one bin is receiving bottom ash, the other bin is decanting the water from the collected bottom ash material. Excess water in the bin flows over a weir, leaving the dewatering bin. Plants can reuse this overflow water directly as bottom ash transport water, send it to an ash impoundment for additional settling, or discharge it directly to surface water.

Most coal and petroleum coke plants operate wet bottom ash handling systems, as described above; however, a substantial number of plants operate a completely dry bottom ash handling system or a system that does not generate ash transport water (e.g., mechanical drag system). As seen in Table 4-9, 112 plants handle at least a portion of their bottom ash dry.[20] These 112 plants represent 22 percent of plants operating a coal-, petroleum coke-, or oil-fired generating unit. Approximately 20 percent of all coal- and petroleum coke-fired generating units use dry bottom ash handling systems. The most common type of dry ash handling system used in the steam electric industry is the mechanical drag chain system. The plant uses a drag chain to remove the bottom ash out of the boiler. The bottom ash is dewatered as the drag chain pulls the bottom ash up an incline, draining the water back to the boiler. The plant then conveys the bottom ash to a nearby collection area from which it is loaded onto trucks and either sold for beneficial use or stored on site in a landfill. Section 7.3 provides more detail on dry and closed-loop recycle bottom ash handling systems.

[20]For the purpose of this report, dry bottom ash handling systems includes all systems that do not generate bottom ash transport water, which includes completely dry bottom ash handling systems, mechanical drag systems, and other mechanical removal systems (e.g., scraping of bottom ash from boiler). Complete recycle and remote mechanical drag systems are considered wet sluicing systems.

Table 4-9. Bottom Ash Handling Practices in the Steam Electric Industry

Bottom Ash Handling	Number of Plants	Coal- and Petroleum Coke-Fired Steam Electric Units		Oil-Fired Steam Electric Units	
		Number of Units	Capacity (MW)	Number of Units	Capacity (MW)
Wet-Sluiced	335 (65%)	863	286,000 (87%)	0-5	0-250 (1%)
Handled Dry [a]	101 (20%)	214	39,900 (12%)	30-35	10,000-15,000 (51%)
Handled Either Wet or Dry	11 (2%)	6	2,610 (1%)	0	0
No Handling System Reported	69 (13%)	12	1,400 (<1%)	57	11, 500 (48%)
Total	**516**	**1,096**	**330,000**	**80 – 95**	**21,900 – 27,900**[b]

Source: Steam Electric Survey, [ERG, 2013].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

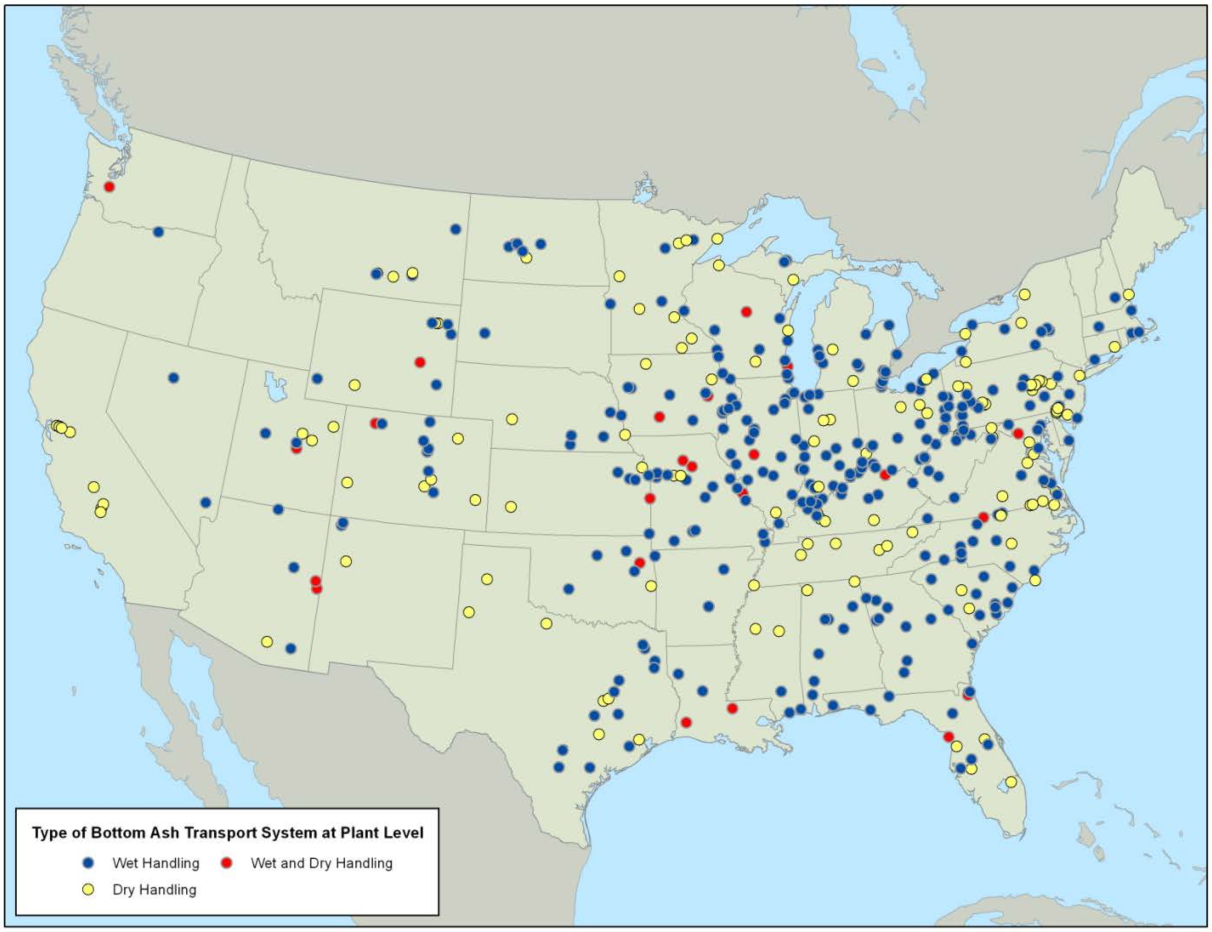
Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric industry are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – Dry bottom ash handling systems include all systems that do not generate bottom ash transport water, which includes completely dry bottom ash handling systems, mechanical drag systems, and other mechanical removal systems (e.g., scraping of bottom of boiler).

b – Total capacity does not include the capacity of three oil units that did not report generating bottom ash.

Table 4-9 shows that 67 percent of plants (79 percent of coal- and petroleum coke-fired generating units) wet sluice all or part of the bottom ash produced. Figure 4-6 shows all plants producing bottom ash in 2009 in the United States with the type of bottom ash handling system identified by different colored symbols. The figure only includes the plants for which responses were provided in the Steam Electric Survey (i.e., the figure does not represent the weighted numbers)



Source: Steam Electric Survey,[ERG, 2013].

Figure 4-6. Plant-Level Bottom Ash Handling Systems

Table 4-10 presents the number of plants within the industry that converted wet sluicing bottom ash operations since 2000. The units and plants are classified by type of dry system installed. Steam electric plants use mechanical drag systems, dry vacuum systems, dry pressure systems, or a handful of other dry handling methods. Each of these handling technologies is discussed further in Section 7. These units represent approximately three percent of the total number of steam electric units that were wet sluicing bottom ash in 2000. Power companies reported plans to convert an additional 67 units to dry or closed-loop recycle bottom ash handling systems by the year 2020.

Bottom ash transport water is typically directed to an on-site ash impoundment for treatment, as described earlier in this section. Steam electric units generate this water intermittently; the frequency depends upon hopper size and the operation of the boiler. Section 6.2 discusses in more detail the amount of bottom ash transport water generated and discharged by the steam electric industry and the pollutant characteristics of the transport water.

Table 4-10. Conversions of Bottom Ash Sluicing Systems Since 2000

Type of Dry Bottom Ash Handling System Installed	Number of Plants	Number of Units	Capacity (MW)
Mechanical Drag System	10-15	15-20	6,500-7,500
Dry Vacuum System	1-5	5-10	250-500
Dry Pressure System	0	0	0
Other	1-5	1-5	100-300
Total [a]	**12 – 25 (3 – 7%)**	**21 – 35 (2 – 4%)**	**6,850 – 8,300 (3%)**

Source: Steam Electric Survey, [ERG, 2013].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

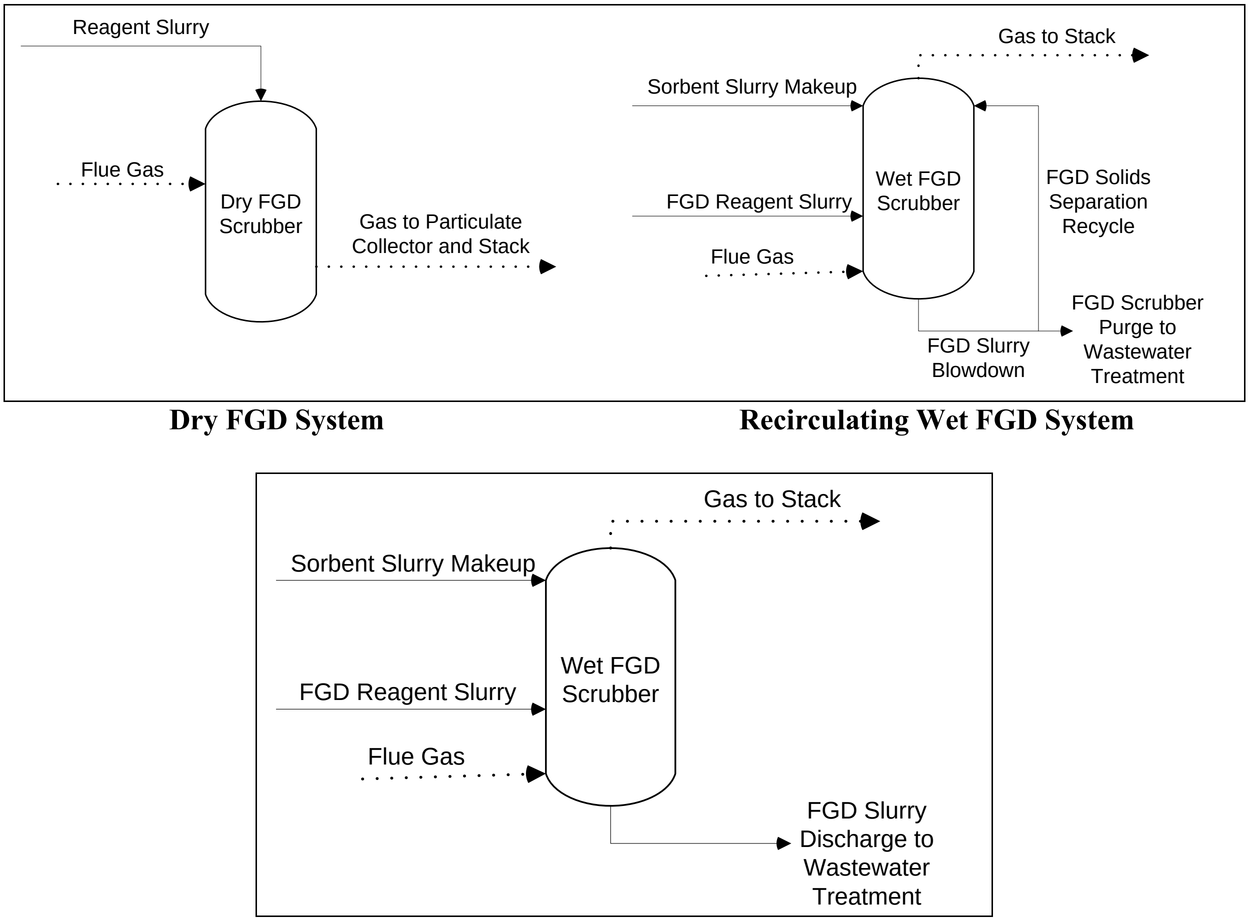
Note: Capacity values are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric industry generated from the Steam Electric Survey are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3

a – The percentages are based on the number of systems conducting any wet sluicing operations (wet sluicing systems and wet and dry systems) in 2000 (excluding units that have retired since that time).

4.3.3 Flue Gas Desulfurization Wastewater

To meet air quality requirements, many power plants that burn coal use a variety of FGD scrubber systems to control SO_2 emissions from flue gas generated in the plant's boiler. These systems are classified as "wet" or "dry." For the purposes of this rulemaking, "wet" FGD systems are those that use a sorbent slurry and that generate a water stream that exits the FGD scrubber absorber. Figure 4-7 presents a simplified diagram of typical wet and dry FGD systems.



Dry FGD System **Recirculating Wet FGD System**

Single Pass Wet FGD System

Figure 4-7. Typical FGD Systems

In dry FGD scrubbers, alkaline reagent slurry is introduced into the hot flue gas stream. The slurry passes through an atomizer and enters the scrubber as a fine mist of droplets. In the scrubber, SO_2 is absorbed as the slurry is evaporated and the flue gas is cooled. Dry FGD scrubbers typically remove between 80 and 90 percent of the SO_2 which is less than a wet FGD system. The amount of water in the reagent slurry is controlled such that it evaporates almost completely in suspension [Babcock & Wilcox, 2005]. Although dry FGD scrubbers use water in their operation, the water in most systems evaporates and they generally do not discharge wastewater. Of the 72 dry FGD plants, 23 generate wastewater during operation and only 2 discharge to a surface water. Wastewater may also be generated during cleaning operations. Of the 72 dry FGD plants, 31 generate wastewater from cleaning operations and only 4 discharge any cleaning wastewater [ERG, 2013]. Dry FGD systems generate smaller, less frequent quantities of wastewater from their operation/cleaning compared to the FGD wastewater from wet systems. EPA did not evaluate the wastewater generated from these dry FGD systems as part of the rulemaking and they would not be subject to the FGD wastewater requirements in the proposed ELGs.

Wet FGD scrubber systems can remove over 90 percent of the SO_2 in the flue gas, and in some cases can remove up to 99 percent. In wet FGD scrubbers, the flue gas stream contacts a liquid stream containing a sorbent, which causes the mass transfer of pollutants from the flue gas to the liquid stream. The sorbents typically used for SO_2 absorption are lime ($Ca(OH)_2$) or limestone ($CaCO_3$), which react with the sulfur in the flue gas to form calcium sulfite ($CaSO_3$). Scrubbers can be operated with forced, inhibited, or natural oxidation systems. In forced oxidation systems, the $CaSO_3$ is fully oxidized to produce gypsum ($CaSO_4 \cdot 2H_2O$). During the scrubbing process, metals and other constituents that were not removed from the flue gas stream by the ESPs may transfer to the scrubber slurry and leave the FGD system via the scrubber blowdown (i.e., the slurry stream exiting the FGD scrubber that is not immediately recycled back to the spray/tray levels). The scrubber blowdown is typically intermittently transferred from the FGD scrubber to the solids separation process. As a result, FGD scrubber purge (i.e., the wastestream from the FGD scrubber system that is transferred to a wastewater treatment system or discharged) is also usually intermittent [ERG, 2013].

Table 4-11 presents the distribution of wet and dry FGD systems reported in the Steam Electric Survey operating in 2009 or planned to be operating by January 1, 2014. Table 4-12 shows the *total scrubbed capacity* of the steam electric units serviced in those systems.[21] There are 401 FGD systems, servicing 458 coal-fired steam electric generating units, reported to be online by January 1, 2014.[22] Of these 401 systems, 311 generate a slurry stream and are considered “wet” FGD systems for the purposes of this rulemaking. Wet FGD systems service 78 percent of scrubbed generating units, representing 84 percent of the total industry scrubbed capacity. These wet systems typically use a limestone slurry with forced oxidation and service generating units burning bituminous coal. Often, plants also operate SCR systems on these generating units to control NO_x emissions (see Section 4.4.4).

Steam electric power plants operating wet FGD systems are located throughout the United States; the largest number is on the eastern United States where more bituminous coal-fired steam electric power plants are located. Figure 4-8 shows the location of all wet scrubbed FGD systems located at the plants noted in Table 4-12. The figure only includes the plants for which responses were provided in the Steam Electric Survey (i.e., the figure does not represent the weighted numbers).

[21] The total scrubbed capacity includes electric power generated by only those steam electric units serviced by an FGD system.

[22] Recent air regulations and new state requirements have resulted in the installation of new wet FGD scrubbers. EPA tried to look ahead to account for these additional wet FGD scrubbers and therefore, because the EPA expects to promulgate the final ELG in 2014, EPA used January 1, 2014 as the baseline for this ELG.

Table 4-11. Types of FGD Scrubbers in the Steam Electric Industry

Type of Scrubber	"Wet" FGD Systems		"Dry" FGD Systems	
	Number of Plants	Number Electric Generating Units	Number of Plants	Number of Electric Generating Units
Circulating Dry	0	0	11	11
Jet Bubbling Reactor	10 - 15	30 - 40	0	0
Mechanically Aided	0	0	1	1
Packed	2	4	1	2
Spray	77	159	1 - 5	1 - 5
Spray/Tray	58	118	0	0
Spray Dryer	1	1	50	69
Tray	1	1	0	0
Venturi	10	23	1 - 5	1 - 5
Other [a]	7	15	5 - 10	7 - 12
No Information [b]	2	2	0	0

Source: Steam Electric Survey, [ERG, 2013].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: A plant may operate multiple electric generating units that may use different types of FGD systems; therefore, the sum of plants may be greater than the total number of plants with FGD systems.

a – The types of scrubber systems classified as 'other' include Advatech Double contact flow scrubbers and dry sodium injection.

b – Insufficient information is available to classify these units/plants in a specific category.

Table 4-12. Characteristics of Coal- and Petroleum Coke-Fired Generating Units with FGD Systems

	Wet FGD Systems			Dry FGD Systems		
	Number of Plants	Number Electric Generating Units	Scrubbed Capacity [a] (MW)	Number of Plants	Number of Electric Generating Units	Scrubbed Capacity [a] (MW)
Total	**145**	**352**	**175,000**	**72**	**97**	**31,800**
Coal Type						
Bituminous	83	196	101,000	28	40	8,730
Subbituminous	27	65	34,900	28	38	16,300
Lignite	5-10	10-15	5,000-6,000	2	3	1,320
Petroleum Coke	1-5	1-5	100-200	0-5	0-5	0-150
Other/Waste Coal	0-5	0-5	0-250	1-5	1-5	500-1,000
Blend [b]	33	81	33,300	8	10	1,880
No Information [c]	4	4	2,420	1-5	5-10	2,600-3,000
Type of Oxidation System						
Forced Oxidation	112	272	138,000	1-5	5-10	800-1,200
Inhibited Oxidation	17	34	19,600	2	3	1,480

Table 4-12. Characteristics of Coal- and Petroleum Coke-Fired Generating Units with FGD Systems

	Wet FGD Systems			Dry FGD Systems		
	Number of Plants	Number Electric Generating Units	Scrubbed Capacity [a] (MW)	Number of Plants	Number of Electric Generating Units	Scrubbed Capacity [a] (MW)
Natural Oxidation	23	47	19,000	5-10	5-15	2,200-2,600
No Information or NA [d]	2	3	860	61	80	27,100
Sorbent						
Lime	10-15	30-40	9,500-10,500	56	74	24,800
Limestone	121	288	146,000	13	18	6,070
Magnesium-Enhanced Lime	10-15	25-35	15,500-16,500	0-5	0-5	0-250
Magnesium Oxide	0	0	0	0	0	0
Soda Ash	3	9	1,880	0	0	0
Sodium Hydroxide	0	0	0	0	0	0
Other	5	14	6,940	14	23	6,340
No Information [d]	1-5	5-10	3,000-4,000	1	1	46
NO_x Controls [e]						
SCR	99	203	117,000	27	32	13,200
SNCR	13-23	35-40	11,500-12,500	12	14	4,070
None/Other (no SCR/SNCR)	56	110	45,700	30-40	45-50	13,500-14,000
No Information [d]	2	2	900	5	5	1,250

Source: Steam Electric Survey, [ERG, 2013].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: Capacity values are rounded to three significant figures.

Note: All 145 wet scrubbed plants and 72 dry scrubbed plants are included in each of the categories presented in this table. Because a plant may operate multiple electric generating units that may represent more than one type of operation in each specific category, the sum of the plants, units, and capacity for each category may be greater than the total.

Note: This table does not account for any plants or units that have identified a retirement between 2009 and January 1, 2014.

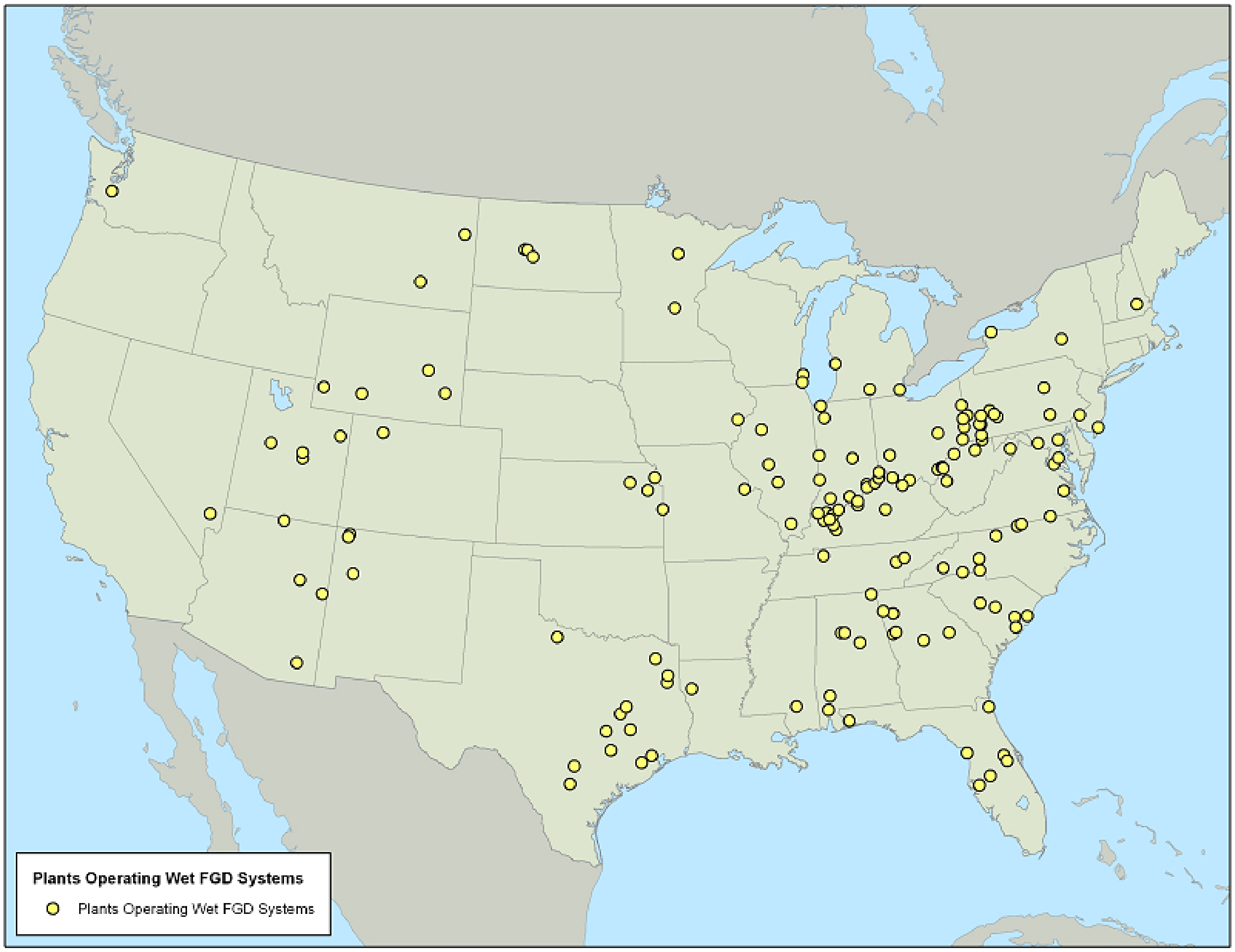
a – The scrubbed capacities represent the reported nameplate capacity for only those units serviced by a scrubber.

b – A coal blend is any combination of two or more different types of coal.

c – The current profile includes planned units whose coal type is not yet available.

d – Insufficient information is available to classify these units/plants in a specific category.

e – Some of the NO_x information included in this category is associated with NO_x systems that are planned or under construction.

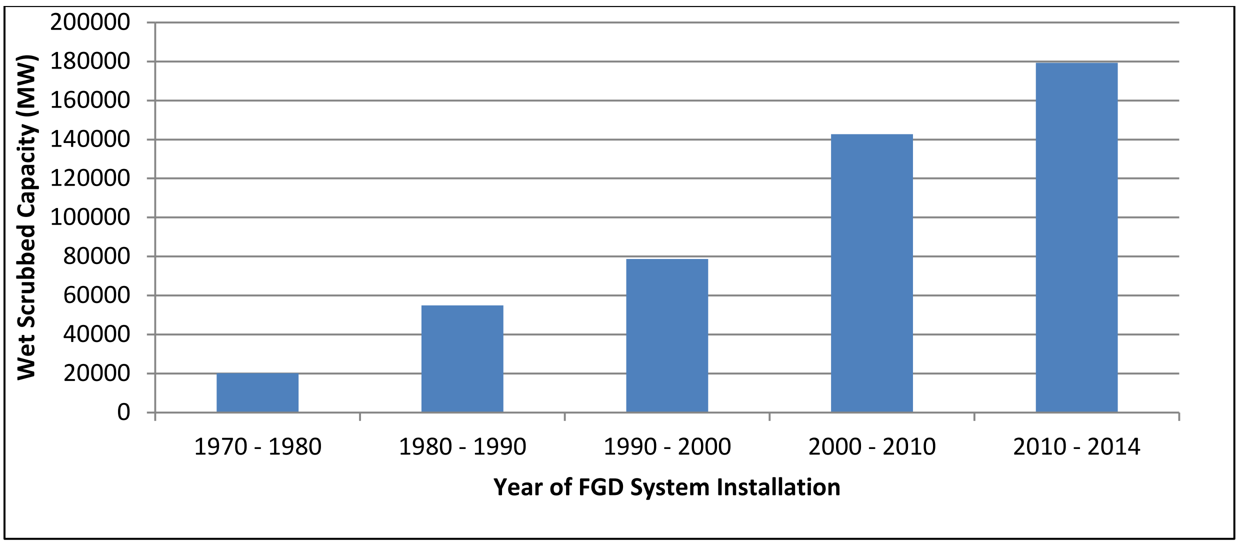


Source: Steam Electric Survey, [ERG, 2013].

Figure 4-8. Plants Operating Wet FGD Scrubber Systems

As shown in Table 4-12, limestone forced oxidation systems are the most common scrubbers reported in the survey. Plants that generate gypsum using limestone forced oxidation systems can market the gypsum for use in building materials (e.g., wallboard), while plants that do not generate gypsum or only partially oxidize the $CaSO_3$ must dispose of their scrubber solids, typically in landfills or impoundments [U.S. EPA, 2006]. Plants that produce a saleable product, such as gypsum, may rinse the product cake to reduce the level of chlorides in the final product and reuse or potentially treat and discharge the wash water along with the FGD scrubber purge. Both sludge by-products (gypsum and $CaSO_3$) typically require dewatering prior to sale, disposal, or processing for reuse. The dewatering process used by plants that generate $CaSO_3$ typically consists thickeners used in conjunction with centrifuges. The dewatering process used by plants that generate gypsum typically consists of hydrocyclones used in conjunction with vacuum filters (either drum or belt). Additionally, some plants may send the FGD blowdown directly to a pond where the FGD solids are scooped out of the pond with a backhoe and stacked on the side of the pond (referred to as "stacking"). The stacking operation is more commonly used by plants generating gypsum, whereas most plants sending FGD wastewater with $CaSO_3$ just let the solids accumulate in the pond. These dewatering processes generate a wastewater stream that the plant likely needs to treat before it is discharged or reused. In the case of the plants sending the FGD blowdown directly to a pond, the pond system is typically the only treatment employed prior to discharge. Section 6.1 provides more detail on the amount of FGD wastewater generated by wet FGD systems.

The installation of wet FGD systems reported in Table 4-12 dates back to 1972. Figure 4-9 shows the total scrubbed capacity of wet FGD systems by decade starting with the 1970s. The figure includes all 311 wet FGD systems identified as operating by January 1, 2014, but it does not include retired units that may have operated with wet FGD systems. Therefore, while the Steam Electric Survey shows an increase in the total wet scrubbed capacity from 1970 to 2010 of 123,000 MW, the actual increase may not be as large because by not including retired units that may have been scrubbed, the scrubbed capacity for earlier years may not be fully represented in the data set. However, based on previous discussions with industry representatives, EPA found that most power companies installed the FGD systems on the largest and newest generating units in their fleets, which are the generating units that are least likely to retire. Therefore, EPA believes that the amount of scrubbed capacity that has been retired over this 45-year period is likely minimal. If that is the case, then the data reasonably reflect the increased use of wet scrubbed FGD systems over the last 45 years.



Source: Steam Electric Survey, [ERG, 2013].

Figure 4-9. Capacity of Wet Scrubbed Units by Decade

Section 6.1 contains information on FGD wastewater characteristics and treatment.

4.3.4 Flue Gas Mercury Control Wastewater

In response to recent Clean Air Act (CAA) rules and other state regulations requiring limits on air emissions of mercury and other air toxics, plants are beginning to install new systems to improve removals of mercury from flue gas emissions, beyond those previously achieved by particulate control systems to remove fly ash. These systems are relatively new to the steam electric industry. According to responses to the Steam Electric Survey, there are generally two types of systems being used to control flue gas mercury emissions:

- Adding oxidizers to the coal prior to combustion, so that the wet FGD system removes the oxidized mercury; and
- Injecting activated carbon into the flue gas, which adsorbs the mercury and is captured in a downstream particulate removal system.

Using the oxidizers does not generate a new wastewater stream, but it may increase the mercury concentration in FGD wastewater because oxidized mercury is more easily removed by the FGD system. However, the activated carbon injection system can generate a new wastestream at a plant, depending on the location of the injection. If the injection occurs upstream of the primary particulate removal system, then the mercury-containing carbon (i.e., FGMC waste) will be collected and handled the same way as the fly ash; therefore, if the fly ash is wet sluiced, then the FGMC wastes are also wet sluiced. In this case, adding the FGMC wastes to the fly ash can increase the pollutant concentration in the fly ash transport water. Section 6.4 provides more detail on how adding FGMC waste affects the characteristics of fly ash. If the injection occurs downstream of the primary particulate removal system, then the plant will need a secondary particulate removal system, typically a fabric filter, to capture the FGMC wastes. Plants typically inject the carbon downstream of the primary particulate collection system if they plan to market the fly ash because adding the FGMC wastes makes the fly ash unmarketable. In this situation, the FGMC wastes, which would be collected with some carry-over fly ash, could be handled either wet or dry.

Based on the responses to the survey, there are approximately 120 currently installed FGMC systems, with an additional 40 new installations planned. Approximately 90 percent of the currently operating FGMC systems are dry systems that do not generate or affect any wastewater streams. Approximately six percent of the currently operating systems are wet systems. The type of handling system (e.g., wet or dry handling) is unknown for the remaining four percent of the systems.

4.3.5 Landfill and Impoundment Leachate and Runoff

Combustion residuals comprise a variety of wastes from the combustion process, including fly ash and bottom ash from coal-, petroleum coke- or oil-fired units; boiler slag; FGD solids (e.g., gypsum and calcium sulfite); FGMC wastes; and other wastewater treatment solids associated with fuel combustion wastewater. Combustion residuals may be stored at the plant in on-site landfills or impoundments. When a landfill or impoundment has reached its capacity, it will typically be closed (i.e., covered) to protect against environmental release of the pollutants contained in the waste. However, these landfills or impoundments may continue to generate leachate.

Leachate is the liquid that drains or leaches from a landfill or an impoundment. Figure 4-10 presents a diagram depicting the generation and collection systems for landfill leachate and stormwater. The two sources of landfill leachate are precipitation that percolates through the waste deposited in the landfill and the liquids produced from the combustion residual placed in the landfill. In addition to leachate, stormwater that contacts the landfill wastes and flows over the landfill may be contaminated. Leachate and contaminated stormwater contain heavy metals and other contaminants through the contact with the combustion residuals. Section 6.3 further discusses the characteristics of leachate.

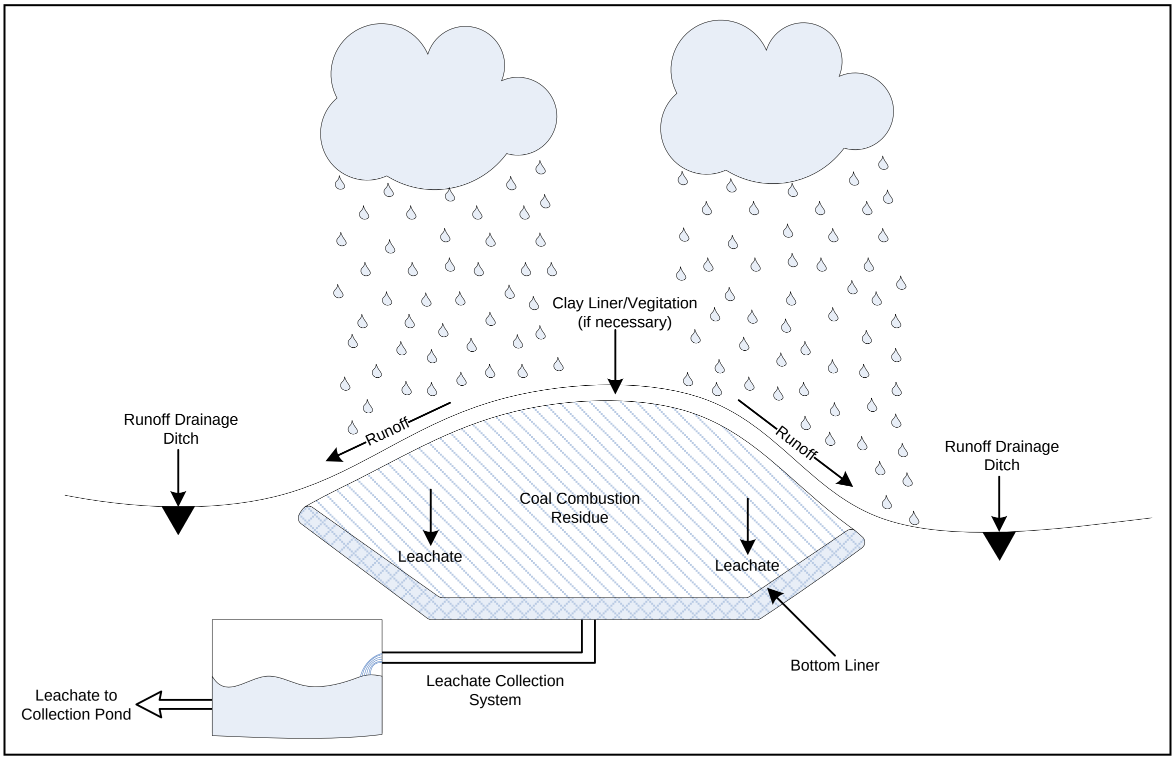


Figure 4-10. Diagram of Landfill Leachate Generation and Collection

In a lined landfill, the leachate collected from the landfill typically flows through a collection system consisting of ditches and/or underground pipes. From the collection system, the plant transports the leachate to a collection impoundment. The stormwater collection systems typically consist of one or more small collection impoundments surrounding the landfill area. Plants may collect the leachate and stormwater in separate impoundments or combine them together in the same impoundment(s). Some plants discharge the effluent from these collection impoundments, while other plants send the collection impoundment effluent to the ash impoundment. Sixty-three percent of the combustion residual landfills reported in the Steam Electric Survey are lined. Impoundments may also have liners and collection systems similar to the landfills; 51 percent of the combustion residual impoundments reported in the Steam Electric Survey are lined. Unlined impoundments and landfills do not collect leachate migrating away from the impoundment/landfill, which can potentially cause ground water and/or drinking water contamination.

Table 4-13 presents the number of plants burning coal or petroleum coke that reported collecting leachate from an impoundment or landfill containing combustion residuals in the Steam Electric Survey. Approximately 100 plants reported collecting landfill leachate from approximately 110 existing (i.e., active or inactive) landfills containing combustion residuals, while approximately 50 plants reported collecting leachate from existing combustion residual impoundments. Another 40 plants reported collecting leachate from both combustion residual landfills and impoundments.

Table 4-13. Leachate Collection at Coal and Petroleum Coke Plants

Type of Leachate Collection	Number of Coal and Petroleum Coke Plants	Number of Combustion Residual Landfills	Number of Combustion Residual Impoundments
Leachate Collection from Landfills Only	90-100	100-110	NA
Leachate Collection from Impoundments Only	40-50	NA	80-90
Leachate Collection from both Landfills and Impoundments	30-40	30-40	60-70

Source: Steam Electric Survey, [ERG, 2013].

Note: Certain fields contain ranges of values to protect the release of information claimed CBI.

Note: Only active and inactive landfills and impoundments are shown in the table.

The majority of landfills installed since 2000 collect leachate. Table 4-14 presents a distribution of each management unit (impoundment or landfill) collecting leachate and the year of installation. Table 4-14 includes data from 283 landfills and 1,100 impoundments. A small percentage of lined landfills do not collect leachate; however, a large percentage of lined impoundments do not collect leachate. Table 4-14 shows that 18 percent of all lined landfills and 74 percent of all lined impoundments do not collect leachate.

Table 4-14. Age of Impoundment or Landfill Collecting Leachate

Management Unit Installation Year	Landfills [a]			Impoundments [b]		
	Total	Number Lined	Number Collecting Leachate	Total	Number Lined	Number Collecting Leachate
2000 to Present	66	55	51	88	77	30
1990 to 2000	53	33	24	96	74	18
1980 to 1990	102	60	49	308	231	34
Before 1980	59	31	22	593	180	66

Source: Steam Electric Survey, [ERG, 2013].

Note: The number of impoundments and landfills in the steam electric industry are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – Three landfills did not provide sufficient date or liner/leachate collection information to be included in this analysis.

b – Fifteen impoundments did not provide sufficient date or liner/leachate collection information to be included in this analysis.

Once collected, the landfill or impoundment leachate can be recycled back into the management unit, recycled elsewhere within the plant, or discharged. Table 4-15 presents the destination of leachate generated from impoundments and landfills. This table includes only those impoundments and landfills reported as producing leachate in Part F of the Steam Electric Survey. The survey data show that at least 28 percent of the impoundment and landfill leachate is returned to the management unit.[23] Most of the returned leachate originates from impoundments. Nearly half of the impoundment leachate systems return the leachate back to the impoundment from which it leached. Plants generally discharge landfill leachate directly after collection, or treat the leachate on site and then discharge after treatment.

Table 4-15. Destination of Leachate in Steam Electric Industry

Destination	Number of Impoundments [a]	Number of Landfills
Returned to Management Unit (impoundment or landfill) or Recycled Within the Plant	48 (47%)	35 (28%)
On-Site Treatment System	6 (6%)	23 (18%)
Discharged	35 (34%)	86 (68%)
Other [b]	21 (20%)	23 (18%)
Total [c]	103	126

Source: Steam Electric Survey, [ERG, 2013].

Note: The number of impoundments and landfills in the steam electric industry are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – Respondents did not provide a leachate destination of any kind for seven impoundments. These impoundments are not represented in the table.

b – "Other" includes perimeter drain with no flow, underground mine pool, and underground injection.

c – Total number of impoundments and landfills is not additive because leachate may have more than one destination. For example, it is possible for leachate from one impoundment to be both treated and discharged.

4.3.6 Gasification Wastewater

IGCC plants generate wastewater from the gasification process, in which a fuel source (e.g., coal or petroleum coke) is subjected to high temperature and pressure to produce a synthetic gas that is used as the fuel for a combined cycle generating unit. As described in Section 4.2.3, the specific processes used to generate the synthetic gas and clean that gas prior to combustion vary to some degree at the currently operating IGCC plants; however, each of these processes require purging wastewater from the process to remove chlorides and other contaminants from the system. Pollutants that may be present in the gasification wastewater include selenium, chromium, arsenic, and cyanide.

As shown in Figure 4-4, there are several wastewater streams generated as part of the IGCC process. Additionally, there may be other wastewaters generated at IGCC plants that are not included in Figure 4-4. The following is a list of the key wastewaters that may be generated at IGCC plants:

[23] Part F of EPA's Steam Electric Survey requested information on the management practices of both impoundments and landfills containing fuel combustion residuals. This section included questions related to the collection and treatment of leachate from both types of management units. As described in Section 3.3, Part F of the questionnaire was sent only to a probability sampled stratum of coal- and petroleum coke-fired plants.

- IGCC-specific wastewaters:
  - Slag handling wastewater;
  - Fly ash and water stream;
  - Sour/grey water (which consists of condensate generated for gas cooling, as well as other wastestreams);
  - CO_2/steam stripper wastewater;
  - Air separation unit blowdown; and
  - Sulfur recovery unit blowdown.

- General power plant wastewaters:
  - Blowdown from the heat recovery steam generator blowdown;
  - Coal/petroleum coke pile runoff;
  - Metal cleaning wastes;
  - Raw water filtration backwash;
  - Demineralizer system reject; and
  - Cooling water.

Depending on the set-up at the plant, most of the general power plant wastewaters would be handled similarly to how they are treated at conventional pulverized coal-fired power plants. Additionally, the slag handling wastewater and the fly ash and water stream may be handled similarly to the fly and bottom ash transport water streams at conventional pulverized coal-fired power plants (i.e., transferred to a surface impoundment prior to discharge). Otherwise, these streams may be recycled back to the slurry preparation system and sent back to the gasifier. The other IGCC-specific wastewaters are treated in a vapor-compression brine concentrator at both of the currently operating IGCC plants. See Section 6.5 for more information on the characteristics of IGCC wastewater.

4.3.7 Metal Cleaning Waste

The Steam Electric Power Generating ELGs define metal cleaning waste as "any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning." [See 40 CFR 423.11]. Plants use chemicals to remove scale and corrosion products that accumulate on the boiler tubes and retard heat transfer. The major constituents of boiler cleaning wastes are the metals of which the boiler is constructed, typically iron, copper, nickel, and zinc. Boiler firesides are commonly washed with a high-pressure water spray against the boiler tubes while they are still hot. Fossil fuels with significant sulfur content will produce sulfur oxides that adsorb on air preheaters. Water with alkaline reagents is often used in air preheater cleaning to neutralize the acidity due to the sulfur oxides, maintain an alkaline pH, and prevent corrosion. The types of alkaline reagents used include soda ash, caustic soda, phosphates, and detergent.

The frequency of metal cleaning activities can vary depending on the type of cleaning operation and individual plant practices. Some operations occur as often as several times a day, while others occur once every several years. Soot blowing, the process of blowing away the soot deposits on furnace tubes, generally occurs once a day, but some units do this as often as several hundred times a day. While 83 percent of units responding to the survey use steam or service air to blow soot, some plants may generate wastewater streams. Air heater cleaning is another frequent cleaning activity. Sixty-six percent of the units perform this operation at least once every two years, while other units perform this cleaning task very infrequently, only once every 40 years. Generally, plants use intake or potable water to clean the air heater [ERG, 2013].

The following is a list of all the metal cleaning wastes that were reported in response to the Steam Electric Survey:

- Air compressor cleaning;
- Air-cooled condenser cleaning;
- Air heater cleaning;
- Boiler fireside cleaning;
- Boiler tube cleaning;
- Combustion turbine cleaning (combustion portion and/or compressor portion);
- Condenser cleaning;
- Draft fan cleaning;
- Economizer wash;
- FGD equipment cleaning;
- Heat recovery steam generator cleaning;
- Mechanical dust collector cleaning;
- Nuclear steam generator cleaning;
- Precipitator wash;
- SCR catalyst soot blowing;
- Sludge lancing;
- Soot blowing;
- Steam turbine cleaning; and
- Superheater cleaning.

4.4 Steam Electric Wastestreams Not Evaluated for New or Additional Controls in the Proposed ELGs

This section describes the wastestreams generated by steam electric power plants for which EPA did not evaluate new or revised discharge requirements for the proposed ELGs. Section 4.3 discusses other wastestreams generated by the steam electric industry the EPA did evaluate for new or revised discharge requirements in the proposed ELGs.

4.4.1 Condenser Cooling Water

As discussed in Section 4.2.1, the steam electric process uses cooling water to condense the steam generated in the boiler; this steam turns the turbines and generates electricity. Because plants are generally generating electricity continuously, plants must provide a constant flow of cooling water to maintain steam condensation and a low pressure in the condenser. Steam electric power plants typically use either once-through or recirculating cooling water systems to condense the steam from the process. Approximately 96 percent of the electric generating units serviced by a cooling system use one of these two types of systems: once-through systems service approximately 52 percent of generating units and recirculating systems service roughly 44 percent. The remaining 4 percent use other methods, most commonly dry cooling systems.

Recirculating systems service roughly 500 coal- or petroleum coke-fired steam electric generating units [Steam Electric Survey]. In a recirculating cooling system, the heated water is sent to a cooling tower to lower its temperature. Plants periodically add fresh water to the cooling water system to make up for evaporative losses. As cooling water evaporates in the cooling tower, dissolved minerals in the water remain behind in the system and increase in concentration over time. To prevent the concentrations of these minerals from building up to unacceptable levels, plants must discharge some of the water, referred to as "cooling tower blowdown," periodically to purge the minerals from the system.

As the cooling water passes through the condenser, microbiological species (e.g., bacterial slimes and algae) stick to and begin growing on the condenser tubes. Steam electric power plants use biocides, such as sodium hypochlorite, sodium bromide, or chlorine gas, to control biofouling on the condenser tubes and cooling tower packing material. Plants may also use chlorine or other antimicrobials, or other methods (e.g., mechanical, thermal) to control macroorganisms.

Once-through cooling systems service roughly 740 coal- or petroleum coke-fired steam electric generating units [ERG, 2013]. In these systems, the cooling water is withdrawn from a body of water, flows through the condenser, and is discharged back to the body of water.

Once-through cooling systems discharge at a significantly higher flow rate than recirculating systems. Table 4-16 provides the average cooling water blowdown rates for each type of cooling system reported in the Steam Electric Survey. Recirculating systems generate blowdown at a rate of approximately 113 MGD, roughly 30 percent of the flow rate generated by once-through systems. Cooling water blowdown is generally a continuous flow, occurring 24 hours per day and 365 days per year.

Table 4-16. Cooling Water Discharge Average Flow Rates Reported in the Steam Electric Industry

Type of Cooling Water System	Number of Cooling Systems	Number of Generating Units Serviced	Capacity of Generating Units (MW)	Average Wastewater Discharge or Blowdown per System (MGD) [a]
Recirculating [b]	950	1,192	321,000	113
Once-Through	666	1,108	298,000	3,730
Other [c]	128	120	26,700	194
Total	1,744	2,420	645,700	1,570

Source: Steam Electric Survey, [ERG, 2013].

Note: Capacity values and wastewater generation rate are rounded to three significant figures.

Note: The number of plants, units, and capacity in the steam electric industry generated from the Steam Electric Survey are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – The average wastewater flow rate per system is calculated from data provided in the Steam Electric Survey. EPA did not include any cooling system with incomplete cooling water flow data.

b – Fifteen generating units (twelve plants) selected ‘other’ for the type of cooling system servicing the units. Two units (one plant) operate a natural draft cooling system and the remaining thirteen units (eleven plants) operate a closed loop cooling system. All eight of these units are classified as recirculating systems.

c – Systems classified as ‘Other’ include dry cooling systems, cooling impoundments, noncontact systems, two-pass systems, and those systems that did not specify a type of cooling system.

Once-through cooling water and cooling tower blowdown may contain the following pollutants, often in low concentrations, as a result of chlorination and corrosion/erosion of the piping, condenser, and cooling tower materials: chlorine, iron, copper, nickel, aluminum, boron, chlorinated organic compounds, suspended solids, brominated compounds, and nonoxidizing biocides.

4.4.2 Coal Pile Runoff

According to the Steam Electric Survey, 99 percent of coal-fired plants store or process coal on site. Coal-fired power plants receive coal via train, barge, or truck. The coal is unloaded in a designated area and conveyed to an outdoor storage area, referred to as the coal pile. Power plants generally store between 25 and 40 days’ worth of coal in the coal pile, but this varies by plant. Some coal-fired plants may have more than one coal pile, depending where the boilers are located and whether the plants use or blend different types of coal. Rainwater and melting snow contacting the coal pile generates a wastestream that contains pollutants from the coal, referred to as coal pile runoff.

Coal pile runoff from the coal-fired power industry generates approximately 3.5 million gallons of wastewater per year [ERG, 2013]. The quantity of runoff at each plant depends upon the amount of precipitation, the physical location and layout of the pile, and the extent to which water infiltrates the ground underneath the pile. As a result, individual flows are often infrequent, with the average plant generating coal pile runoff a total of 131 days per year [ERG, 2013]. Coal pile runoff is usually collected in a runoff impoundment during or immediately after times of rainfall.

EPA collected data on the pH of coal pile runoff impoundments during several site visits to coal-fired steam electric power plants. The pH of coal pile runoff holding impoundments ranges from 2.8 to 8.5 S.U. In general, coal pile runoff impoundments containing other wastewaters, specifically limestone pile runoff, have a higher pH because the limestone pile runoff neutralizes the acidity of the coal pile runoff [ERG, 2008a – 2008e, 2008g; ERG, 2009a, 2009b, 2009d – 2009f].

4.4.3 Selected Low Volume Waste Sources

Low volume waste sources, as currently defined by the existing Steam Electric Power Generating ELGs, include a variety of wastestreams, such as wastewater associated with wet scrubber air pollution control systems, ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes, and recirculating house service water systems. See 40 CFR 423.11. The proposed ELGs would remove specific wastewaters from this collective group of low volume waste sources. As discussed in Section 8.1.1, EPA is proposing to exclude FGD wastewater, combustion residual leachate, and carbon capture wastewater from the low volume waste source category. Plants typically combine low volume wastes with other plant wastewaters for treatment, often in surface impoundments. In some cases, low volume wastewaters can be recycled within the plant. Table 4-17 shows the distribution of some of the low volume wastestreams. This table includes the number of plants generating each waste and the minimum and maximum flows as reported in the Steam Electric Survey.

Table 4-17. Selected Low Volume Waste Sources in the Steam Electric Industry

Type of Wastestream	Number of Plants [a]	Minimum Flow [b] (GPY)	Maximum Flow [b] (GPY)
Ion Exchange Wastewater	134	2,590	60,400,0000
Boiler Blowdown	164	3,790	616,000,000
Evaporator Blowdown	1	1,830,000	1,830,000
Floor Drains	220	12,000	10,500,000,000

Source: Steam Electric Survey, [ERG, 2013].

Note: Wastewater flow rates are rounded to three significant figures.

Note: The table presents a subset of wastestreams that survey responses clearly identified and for which flows were reported.

Note: The number of plants in the steam electric industry generated from the Steam Electric Survey are based on values reported in the survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – The number of plants reported as generating each wastestream is based on the total number of plants listing the specific wastestream as an influent to an impoundment or wastewater treatment system in the Steam Electric Survey and then weighted to represent all plants within the Steam Electric Industry. This includes commingled streams or streams for which a flow rate was not provided.

b – Minimum and maximum flows do not include flow rates for commingled streams. This data only represents the flow rates that were reported in the Steam Electric Survey.

4.4.4 Selective Catalytic Reduction and Selective Non-Catalytic Reduction Wastewater

SCR and selective noncatalytic reduction (SNCR) are technologies used to control nitrogen oxide (NO_x) emissions in the flue gas from the boiler. Based on survey responses, EPA identified 426 plants operating at least one SCR system and an additional 97 plants operating at least one SNCR system. In SCR, ammonia (NH_3) is injected into the flue gas upstream of a catalyst, such as vanadium or titanium. The NO_x in the flue gas (comprising mainly nitrogen monoxide (NO) with lesser amounts of nitrogen dioxide (NO_2)) reacts with the NH_3 in the presence of oxygen and the catalyst to form nitrogen and water. SNCR utilizes either ammonia or urea injected into the flue gas within a specific temperature zone. As with SCR technologies, the NO_x in the flue gas reacts with the reducing agent, either ammonia or urea, in the presence of oxygen to form nitrogen and water.

In addition to forming nitrogen and water, a fraction of the SO_2 in the flue gas may be oxidized to sulfur trioxide (SO_3), and other side reactions may produce ammonium sulfate ($(NH_4)_2SO_4$) and ammonium bisulfate (NH_4HSO_4) as by-products. These by-products can foul and corrode downstream equipment. The extent to which they form depends upon various factors within the process, including the sulfur content of the coal used in the boiler and the amount of excess NH_3 in the system. Unreacted NH_3 in the flue gas from the SCR/SNCR is commonly termed *ammonia slip* [Babcock & Wilcox, 2005].

Plants may use different SCR/SNCR configurations based on the particular operations of the system, including placing the SCR/SNCR upstream of the air heater and other emission control devices such as a FGD scrubber and/or particulate removal device (e.g., ESP).[24] Although the SCR/SNCR does not produce a wastestream during operation, it can affect the characteristics of fly ash transport water, air heater wash water, and FGD wastewater. As previously explained, unreacted NH_3 and SO_3 by-product can create $(NH_4)_2SO_4$ and NH_4HSO_4, which can deposit in the air heater and must be removed through periodic washes. The collection of the $(NH_4)_2SO_4$ and NH_4HSO_4 affect the characteristics of the air heater wash water and also lead to more frequent washing. The fly ash transport water characteristics can be affected by the SCR operation because ammonia that passes unreacted through the SCR/SNCR may attach to the particulates in the flue gas and be removed from the flue gas in the air pollution control equipment (e.g., ESP, baghouse, FGD scrubber). Because ammonia is soluble, if the ash collected from the particulate removal device is handled with a wet system (e.g., wet sluicing), then the ammonia will likely partition into the wastewater and be discharged from the plant [Wright, 2003].

In addition to affecting fly ash transport water and FGD wastewater characteristics, SCR systems could potentially need associated other cleaning operations that generate a wastestream, including catalyst regeneration wastewater and wastewater from washing the catalyst bed. According to survey responses, no plants reported generating SCR catalyst regeneration wastewater in 2009. Three plants reported generating wastewater from washing the SCR catalyst bed. Catalyst bed washing occurs infrequently, from twice per year to once every six years, and generates up to 1,080,000 gallons of wastewater per event. The plants reported commingling the

---

[24] The air heater utilizes the heat contained in the flue gas to increase the temperature (via heat exchange) of the air injected into the boiler for combustion.

catalyst bed wash water with other wastestreams and treating them on site prior to discharge [ERG, 2013].

4.4.5 Carbon Capture Wastewater

Due to potential future regulations on carbon dioxide (CO_2) emissions, many steam electric power plants are considering alternatives available for reducing carbon emissions.

There are three main approaches for capturing the CO_2 associated with generating electricity: postcombustion, precombustion, and oxyfuel combustion.

- In post-combustion capture, the CO_2 is removed after the fossil fuel is combusted.
- In precombustion capture, the fossil fuel is partially oxidized, such as in a gasifier. The resulting syngas (CO and H_2) is shifted into CO_2 and more H_2 and the resulting CO_2 can be captured from a relatively pure exhaust stream before combustion takes place.
- In oxyfuel combustion, also known as oxycombustion, the fuel is burned in oxygen instead of air. The flue gas consists of mainly CO_2 and water vapor; the latter is condensed through cooling. The result is an almost pure CO_2 stream that can be transported to the storage, or sequestration, site and stored.

After capture, the plant would transport CO_2 to a suitable sequestration site. Approaches under consideration include the following:

- Geologic sequestration (injection of the CO_2 into an underground geologic formation);
- Ocean sequestration (typically injecting the CO_2 into the water column at depths to allow dissolution or at deeper depths where the CO_2 is denser than water and would form CO_2 "lakes"); and
- Mineral storage (where CO_2 is exothermically reacted with metal oxides to produce stable carbonates).

Based on preliminary information regarding these technologies, EPA believes these systems may result in new wastestreams at steam electric power plants that will need to be addressed. However, as these technologies are currently in the early stages of research and development and/or pilot testing, the industry has little information on the potential wastewaters generated from carbon capture processes.

As part of EPA's sampling program, EPA obtained analytical data from two wastestreams generated from a post-combustion carbon capture pilot-scale system. The pilot-scale system was based on Alstom's chilled ammonia process. This carbon capture process generated a few wastewater bleed streams, two of which were analyzed as part of EPA's sampling program. The first stream, a pilot validation facility (PVF) bleed stream, is a purge stream that removes ammonium sulfate from the process. During sampling activities, the PVF bleed stream flow rate ranged from 800 to 5,100 gallons per day (gpd). The second stream, flue gas condensate, is a condensate stream generated from cooling the flue gas, which condenses the water vapor present. The flow rate of the flue gas condensate stream ranged from 2,600 to 9,900 gpd during sampling. Table 4-18 presents the concentrations of the pollutants measured during the EPA sampling program. The concentrations presented are the 4-day average concentrations.

According to plant personnel, for a full-scale system, a plant would transfer the PVF bleed stream to a crystallizer, producing a solid particulate product which could be used as a fertilizer [Lohner, 2010]. The condensate from the evaporation process could be reused in other plant processes or discharged.

Table 4-18. Carbon Capture Wastewater 4-Day Average Concentration Data

Analyte	Unit	4-Day Average Concentration	
		PVF Bleed Stream	Flue Gas Condensate
Classicals			
Ammonia	mg/L	26,800	< 383
Nitrate Nitrite as N	mg/L	8.98	1.80
Nitrogen, Total Kjeldahl	mg/L	42,800	740
Biochemical Oxygen Demand	mg/L	ND (14.7)	< 3.65
Chemical Oxygen Demand	mg/L	88.8	NQ (20.0)
Chloride	mg/L	NQ (300)	NQ (6.75)
Sulfate	mg/L	163,000	1,050
Cyanide, Total	mg/L	1.20	ND (0.100)
Total Dissolved Solids	mg/L	163,000	1,050
Total Suspended Solids	mg/L	27.3	< 6.75
Phosphorus, Total	mg/L	0.155	NQ (0.0500)
Total Metals			
Aluminum	ug/L	450	NQ (200)
Antimony	ug/L	2.65	ND (2.00)
Arsenic	ug/L	40.0	NQ (4.00)
Barium	ug/L	57.5	NQ (20.0)
Beryllium	ug/L	ND (2.00)	ND (2.00)
Boron	ug/L	13,000	1,540
Cadmium	ug/L	NQ (4.00)	ND (4.00)
Calcium	ug/L	24,000	< 2,390
Chromium	ug/L	1,540	< 17.5
Cobalt	ug/L	73.3	NQ (20.0)
Copper	ug/L	400	14.9
Iron	ug/L	4,380	2,020
Lead	ug/L	7.78	NQ (2.00)
Magnesium	ug/L	15,800	1,990
Manganese	ug/L	965	101
Mercury	ng/L	3,530	1,060
Molybdenum	ug/L	2,630	NQ (40.0)

Table 4-18. Carbon Capture Wastewater 4-Day Average Concentration Data

Analyte	Unit	4-Day Average Concentration	
		PVF Bleed Stream	Flue Gas Condensate
Nickel	ug/L	4,530	27.5
Selenium	ug/L	4,900	128
Silver	ug/L	ND (2.00)	ND (2.00)
Sodium	ug/L	16,000	NQ (10,000)
Thallium	ug/L	2.30	ND (2.00)
Tin	ug/L	ND (200)	ND (200)
Titanium	ug/L	NQ (20.0)	NQ (20.0)
Vanadium	ug/L	19.0	NQ (10.0)
Zinc	ug/L	293	NQ (40.0)

Source: CWA 308 Monitoring, [ERG, 2012].

< – Average result includes at least one value measured below the quantitation limit. (Calculation uses ½ the sample-specific quantitation limit for values below the quantitation limit).

ND – Not detected (number in parenthesis is the quantitation limit).

NQ – Analyte was measured below the quantitation limit for all four results (number shown in parenthesis is the average quantitation limit), but at least one result was measured above the method detection limit.

Note: Concentrations are rounded to three significant figures.

According to the survey responses, there are no full-scale carbon capture systems operating in the industry. There are, however, two pilot-scale systems that have been in operation, the one for which EPA collected the analytical data presented in Table 4-18 (currently shut down and inactive) and another one that has been decommissioned. Additionally, several plants reported in their survey responses that they are planning to install a pilot-scale carbon capture system and some plants even reported plans to install full-scale systems.

In March 2012, EPA proposed a Carbon Pollution Standard for New Power Plants (FR Doc No: 2012-7820), which would set national limits on the amount of carbon pollution future power plants can emit. The proposed carbon pollution standard does not apply to existing plants or those permitted to begin construction by 2013. The proposed rule will allow future plants to choose to burn any fossil fuel to generate electricity, but would require these plants to incorporate technologies to reduce the carbon dioxide emissions to meet a standard of 1,000 pounds of CO_2 per megawatt-hour. This rule will likely have the greatest impact on coal-, petroleum coke-, and oil-fired plants because new natural gas combined cycle units should be able to meet the proposed standard without additional CO_2 controls [U.S. EPA, 2012].

4.5 References

1. Babcock & Wilcox Company. 2005. *Steam: Its Generation and Use*. 41st edition. Edited by J.B. Kitto and S.C. Stultz. Barberton, Ohio. DCN SE02919.
2. Eastern Research Group (ERG). 2008a. Final Site Visit Notes: Appalachian Power Company's Mountaineer Plant. (11 September). DCN SE02070.

3. Eastern Research Group (ERG). 2008b. Final Site Visit Notes: Kentucky Utilities Company's Ghent Generating Station. (19 December). DCN SE02079.
4. Eastern Research Group (ERG). 2008c. Final Site Visit Notes: Louisville Gas and Electric Company's Cane Run Station. (11 December). DCN SE02082.
5. Eastern Research Group (ERG). 2008d. Final Site Visit Notes: Louisville Gas and Electric Company's Mill Creek Station. (December 12). DCN SE02083.
6. Eastern Research Group (ERG). 2008e. Final Site Visit Notes: Louisville Gas and Electric Company's Trimble County Station. (10 December). DCN SE02080.
7. Eastern Research Group (ERG). 2009a. Final Site Visit Notes: Alleghany Energy's Harrison Power Station. (20 January). DCN SE02069.
8. Eastern Research Group (ERG). 2009b. Final Site Visit Notes: CPS Energy's Calaveras Power Station. (29 October). DCN SE02076.
9. Eastern Research Group (ERG). 2009c. Final Site Visit Notes: Duke Energy's Wabash River Generating Station. (12 October). DCN SE02095.
10. Eastern Research Group (ERG). 2009d. Final Site Visit Notes: Fayette Power Project/Sam Seymour Power Station. (30 October). DCN SE02077.
11. Eastern Research Group (ERG). 2009e. Final Site Visit Notes: Ohio Power Company's Gavin Plant. (19 January). DCN SE02072.
12. Eastern Research Group (ERG). 2009f. Final Site Visit Notes: Tennessee Valley Authority's Paradise Fossil Plant. (20 September). DCN SE02101.
13. Eastern Research Group (ERG). 2009g. Final Site Visit Notes: Western Kentucky Energy's Kenneth C. Coleman Station. (23 February). DCN SE02094.
14. Eastern Research Group (ERG). 2011. Final Site Visit Notes: TECO Energy's Polk Power Station. (2 March). DCN SE00071.
15. Eastern Research Group (ERG). 2012. Final Power Plant Monitoring Data Collected Under Clean Water Act Section 308 Authority ("CWA 308 Monitoring Data"). (30 May). DCN SE01326.
16. Eastern Research Group (ERG). 2013. Steam Electric Technical Questionnaire Database ("Steam Electric Survey"). (19 April). DCN SE01958.
17. Lohner, Tim. 2010. Email to Ron Jordan of U.S. EPA from Tim Lohner of AEP. (6 December). DCN SE01335.
18. USCB. 2007. U.S. Census Bureau. *Electric Power Generation, Transmission, and Distribution: 2007 Economic Census Utilities Industry Series*. Document and data are available online at: http://www.census.gov/econ/census07/. DCN SE01802.
19. U.S. EPA. 1982. *Development Document for Effluent Limitations Guidelines and Standards and Pretreatment Standards for the Steam Electric Point Source Category*. EPA-440-1-82-029. Washington, DC. (November). DCN SE02933.
20. U.S. DOE. 2006. U.S. Department of Energy. *Introduction to Nuclear Power*. Energy Information Administration (EIA). Available online at:

http://www.eia.doe.gov/cneaf//page/intro.html. Date accessed: August 2006. DCN SE01803.

21. U.S. DOE. 2009. U.S. Department of Energy. Annual Electric Generator Report (collected via Form EIA-860). Energy Information Administration (EIA). The data files are available online at: http://www.eia.doe.gov/cneaf//page/eia860.html. DCN SE01805.
22. Wright, Thomas. 2003. "SCR Operation Optimization: SO_3 Removal to Optimize Catalyst Life & NH_3 Distribution in Wastewater." In: Proceedings from the Selective Catalytic/Non-Catalytic Reduction Conference. Chattanooga, TN. (October 30). DCN SE02934.
23. U.S. DOE. U.S. Department of Energy. *Energy Efficiency and Renewable Energy - Geothermal Technologies Program*. Available online at: http://www1.eere.energy.gov/al/faqs.html and http://www1.eere.energy.gov//powerplants.html. DCN SE01804.

SECTION 5
INDUSTRY SUBCATEGORIZATION

This section presents information about factors EPA considered in evaluating whether different limitations or standards are warranted for certain facilities in the steam electric power generating point source category. Section 5.1 describes why EPA considers factors that could lead to establishing different requirements for certain facilities in the point source category and presents background on the industry categorization established in the 1974 and 1982 ELG rulemakings. Section 5.2 presents the factors considered in detail and reviews the analyses EPA performed to review whether subcategorization was necessary to the revisions proposed.

5.1 SUBCATEGORIZATION FACTORS

The CWA requires EPA to consider a number of different factors when developing ELGs for a particular industry category (Section 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B)). For BAT, in addition to the technological availability and economic achievability, these factors are the age of the equipment and plants, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impacts (including energy requirements), and such other factors the Administrator deems appropriate. One way EPA may take these factors into account, where appropriate, is by dividing a point source category into groupings called "subcategories." Regulating a category by subcategory, where determined to be warranted, ensures that each subcategory has a uniform set of ELGs that take into account technology availability and economic achievability and other relevant factors unique to that subcategory.

The current Steam Electric ELGs do not divide plants or process operations into subcategories, although they do include different effluent requirements for cooling water discharges from generating units smaller than 25 MW generating capacity [U.S. EPA, 1974; U.S. EPA, 1982]. For this proposed rule, EPA evaluated whether different effluent requirements should be established for certain facilities within the steam electric power generating point source category using information from responses to the industry surveys, site visits, sampling, and other data collection activities (see Section 3 for more details). EPA performed analyses to assess the influence of age, size, fuel type, and geographic location on the wastewaters generated, discharge flow rates, pollutant concentrations, and treatment technology availability at steam electric power plants to determine whether subcategorization was appropriate.

5.2 ANALYSIS OF SUBCATEGORIZATION FACTORS

EPA performed analyses to assess the influence of age, size, fuel type, and geographic location on the wastewaters generated at steam electric power plants and the availability of technologies to manage those wastewaters. The following sections summarize the analyses performed as part of the subcategorization reevaluation. For additional information on the specific analyses performed as part of the reevaluation, see the memorandum entitled "Subcategorization Memorandum" [ERG, 2013a].

5.2.1 Age of Plant or Generating Unit

EPA analyzed the age of the power plants and the generating units included in the scope of the rule. EPA determined that the age of the plant by itself does not in general impact the wastewater characteristics, the processes in place, or the ability to install the treatment technologies evaluated as part of this rulemaking [ERG, 2013a]. Therefore, EPA did not establish subcategories based solely on the age of the plant or generating unit for this proposed rule.

5.2.2 Geographic Location

EPA analyzed the geographic location of power plants included in the scope of the rule. EPA determined that the geographic location of the plant by itself does not affect the wastewater characteristics, the processes in place, or the ability to install the treatment technologies evaluated as part of this rulemaking. During its evaluation, EPA did find that wet FGD systems, both wet and dry fly ash handling systems, and both wet and dry bottom ash handling systems are located throughout the United States, as illustrated in Section 4. Additionally, the location of the plant does not affect the plant's ability to install the treatment technologies evaluated as part of this rulemaking. For example, a plant in the southern United States will be able to install and operate the chemical precipitation and biological treatment system proposed as the BAT technology basis for FGD wastewater. Because of the warm climate, plants in locations such as this may find it necessary to install heat exchangers to keep the FGD wastewater temperature at ideal operating conditions during the summer months. EPA's approach for estimating compliance costs takes such factors into account. Based on the information in the record regarding the current geographic location of the various types of systems generating the wastewaters addressed by this rulemaking and engineering knowledge of the operational processes and candidate BAT/NSPS treatment technologies, EPA determined that subcategories based on plant location are not warranted.

5.2.3 Size

EPA analyzed the size (i.e., nameplate generating capacity in MW) of the steam electric generating unit and determined that it is an important factor influencing the volume of the discharge flow from the plant. Typically, as the size of the generating unit increases, the discharge flows of ash transport water generally increase. In general, this is to be expected because the larger the generating unit, the more fuel it consumes, which generates more ash, and uses more water in the water/steam thermodynamic cycle [ERG, 2013b]. Although the volume of the wastewater increases with the size of the generating unit, the pollutant characteristics of the wastewater generally are unaffected by the size of the generating unit and any variability observed in wastewater pollutant characteristics does not appear to be correlated to generating capacity.

As a result of its evaluation, EPA believes that, in certain circumstances, it would be appropriate to apply different limits for a class of existing generating units or plants based on size. Section 8 discusses in greater detail EPA's proposal for applying different standards to certain existing units and plants.

5.2.4 Fuel Type

The type of fuel (e.g., coal, petroleum coke, oil, gas, nuclear) used to create steam most directly influences the type and number of wastestreams generated. For example, gas and nuclear power plants typically generate cooling water, metal cleaning wastes (both chemical and nonchemical), and other low volume wastestreams, but do not generate wastewaters associated with air pollution control devices (e.g., fly ash and bottom ash transport water, FGD wastewater). Coal, oil, and petroleum-coke power plants may generate all of those wastewaters. The wastestream that is most influenced by fuel selection is the ash transport water because the quantity and quality of ash generated from oil-fired units is different from that generated from coal- and petroleum coke-fired units. Additionally, the quantity and quality of ash differs based on the type of oil used in the boiler. For example, heavy or residual oils such as No. 6 fuel oil generate fly ash and may generate bottom ash, but lighter oils such as No. 2 fuel oil may not generate any ash.

From an analysis of responses to the Steam Electric Survey, EPA determined that 74 percent of the steam electric units in the industry burn more than one type of fuel (e.g., coal and oil, coal and gas). Some of these plants may burn only one fuel at a specific time, but burn both types of fuels during the year. Other plants may burn multiple fuels at the same time. In cases where facilities burn multiple fuels at the same time, it would be impossible to separate the wastestreams by fuel type [ERG, 2013b].

EPA did not identify any basis for subcategorizing gas-fired and nuclear generating units. These generating units generally manage nonchemical metal cleaning wastes in the same manner as other steam electric generating units, and the proposed requirements for this wastestream would establish limitations and standards that are equal to current BPT limitations for existing direct dischargers.[25] Furthermore, the gas-fired and nuclear generating units do not generate the other six wastestreams addressed by this rulemaking. However, based on responses to the Steam Electric Survey, there are some oil-fired units that generate and discharge fly ash and/or bottom ash transport water. For these reasons, EPA looked carefully at oil-fired units. As a result, EPA believes that, in certain circumstances, it is appropriate to apply different limits to existing oil-fired generating units. Section 8 discusses in greater detail EPA's proposal for applying different standards to certain existing oil-fired units.

5.3 References

1. Eastern Research Group (ERG). 2013a. Steam Electric Technical Questionnaire Database ("Steam Electric Survey"). (19 April). DCN SE01958
2. Eastern Research Group (ERG). 2013b. Memorandum to the Steam Electric Rulemaking Record. Subcategorization Memorandum." (19 April). DCN SE02127.
3. U.S. EPA. 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C. (October). DCN SE02917.

[25] As described in Section 8, EPA is proposing to exempt from new copper and iron BAT limitations any existing discharges of nonchemical metal cleaning wastes that are currently authorized without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits applicable to low volume wastes.

4. U.S. EPA. 1982. *Development Document for Effluent Limitations Guidelines and Standards and Pretreatment Standards for the Steam Electric Point Source Category*. EPA-440-1-82-029. Washington, DC. (November). DCN SE02933.

SECTION 6 WASTEWATER CHARACTERIZATION AND POLLUTANTS OF CONCERN

This section summarizes information gathered from survey data, EPA sampling data, Clean Water Act (CWA) 308 sampling data, and industry-submitted sampling data on wastewater generation practices associated with the steam electric industry. Sections 6.1 through 6.6 provide details on only those wastestreams for which EPA evaluated new or revised discharge requirements for the proposed ELGs, those discussed in Section 4.3, including flue gas desulfurization (FGD) wastewater, ash transport water, combustion residual landfill leachate, flue gas mercury control (FGMC) wastewater, gasification wastewater, and metal cleaning waste. Each section provides detail on wastewater generation rates and provides characterization data for the untreated process wastewater, where available. Section 6.7 identifies the pollutants of concern (POCs) related to this rulemaking.

6.1 FGD WASTEWATER

Wet FGD scrubber systems are classified into two categories, recirculating wet FGD systems and single pass wet FGD systems, as shown in Figure 4-7. In a recirculating system, most of the FGD slurry at the bottom of the scrubber is recirculated back within the scrubber and occasionally a blowdown stream is transferred away from the scrubber, called FGD slurry blowdown. The slurry blowdown stream undergoes solid separation and the wastewater is either recycled back to the scrubber or transferred to a wastewater treatment system as FGD scrubber purge. In a single pass system, all of the FGD slurry at the bottom of the scrubber is leaves the scrubber without recirculating the slurry within the system. FGD wastewater can include the FGD scrubber purge from a recirculating systems, the FGD slurry from single pass systems, any gypsum wash water, and water generated from the solids dewatering process. This section describes the amount of FGD wastewater generated by FGD systems at coal-fired power plants within the steam electric industry and discusses the characteristics of FGD wastewater.

As described in Section 4.3.3, the FGD wastewater generated by wet FGD systems needs to be removed to purge chlorides from the system. This FGD wastewater is typically generated intermittently. The factors that can affect the characteristics and flow rate of the FGD wastewater include the type of coal, scrubber design and operating practices, solids separation process, and solids dewatering process used at the plant, which are discussed below.

The type of coal burned at the plant can affect the FGD wastewater flow rate. Generally, burning a higher sulfur coal will require a higher FGD wastewater flow from the system. Higher sulfur coals produce more sulfur dioxide in the combustion process, which in turn increases the amount of sulfur dioxide removed in the FGD scrubber. As a result, more solids are generated in the reaction in the scrubber, which increases frequency at which FGD wastewater is removed from the system and transferred to treatment.

Likewise, the use of a high chlorine coal can increase the volume and frequency of the FGD wastewater generated by the system. Many FGD systems are designed with materials resistant to corrosion for specific chloride concentrations. The chlorine present in the coal leads to chlorides present in the FGD systems. As the FGD system recirculates the water in the system, the chlorides build up within the scrubber. The plant will have to purge some of the wastewater to remove the chlorides from the system as the chloride concentration in the scrubber begins approaching the maximum allowable limit for the specific material of construction of the FGD system. In the United States, FGD scrubbers are generally constructed of alloys that are designed to withstand a chloride concentration of 20,000 parts per million (ppm) or more. The larger the maximum allowable chloride concentration in the scrubber, the lower the FGD wastewater flow rate; however, this lower purge rate leads to additional cycling in the scrubber, which increases the pollutant concentrations in the FGD wastewater [Babcock and Wilcox, 2005].

Table 6-1 summarizes the FGD slurry blowdown generated by the steam electric industry in 2009 as reported in the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey). On average, a steam electric power plant generates 1.2 million gallons per day (MGD) of FGD slurry blowdown. As described above, the FGD slurry blowdown undergoes dewatering before being transferred to treatment or recycled back to the scrubber.

Table 6-1. FGD Slurry Blowdown Flow Rates

	Number of Plants	Average Flow Rate	Median Flow Rate	Range of Flow Rate
Flow Rate per Plant				
Gallons per day (gpd)/plant	137	1,220,000	598,000	3,300 – 22,000,000

Source: Steam Electric Survey, [ERG, 2013b].

Note: Flows are rounded to three significant figures.

Note: Two plants are missing data and are therefore not included in the count of plants presented in this table. An additional six (6) plants identified plans for a future FGD system that will generate FGD blowdown. These future FGD systems are also not included in the count of plants represented in this table.

The pollutant concentrations in FGD wastewater vary from plant to plant depending on the coal type, the sorbent used, the materials of construction in the FGD system, the FGD system operation, the level of recycle within the absorber, and the air pollution control systems operated upstream of the FGD system. The fuel (coal or petroleum coke) is the source of most of the pollutants that are present in the FGD wastewater (i.e., the pollutants in the coal are likely to be in the FGD wastewater). The sorbent used in the FGD system also introduces pollutants into the FGD wastewater and, therefore, the type and source of the sorbent used affects the pollutant concentrations in the FGD wastewater.

The materials of construction in the FGD system and the FGD system operation affect the types of pollutants in the wastewater, as well as their concentrations. Using organic acid additives contributes to higher concentrations of biochemical oxygen demand (BOD_5) in the FGD wastewater. Additionally, the type of oxidation the FGD system uses (i.e., forced oxidation, inhibited oxidation, natural oxidation) can affect the form of the pollutants present in the FGD wastewater. According to the Electric Power Research Institute (EPRI), forced oxidation systems produce most of the selenium present as selenate (Se^{+6}) whereas natural and inhibited oxidation systems produce most of the selenium present as selenite (Se^{+4}) [EPRI, 2006]. The FGD wastewater characteristics presented later in this section represent data from plants operating forced oxidation systems. EPA focused the sampling program on plants operating forced oxidation systems for the following reasons:

Most plants operating natural or inhibited oxidations systems do not discharge FGD wastewater because they either operate complete recycle systems or because the water is evaporated in evaporation ponds or during a pozzolonic reaction.

Selenate is the form of selenium that is more difficult to treat; therefore, if the technology option selected as the basis for the ELGs can remove the selenate, it will also be able to remove the selenite. Additionally, the biological treatment process used as the basis for Regulatory Options 3 and 4 reduces both selenate and selenite to its elemental form; therefore, the form of selenium present in the wastewater does not impact the removals achieved by the preferred options.

The materials of construction and the other FGD system operations can also affect the concentration of pollutants in the FGD wastewater because they affect the amount of recycle within the system, which in turn, affects the rate at which the FGD wastewater is generated. For example, during the detailed study, EPA collected samples from the Tennessee Valley Authority's Widows Creek Fossil Plant (Widows Creek), which operates once-through FGD systems. These FGD systems do not cycle the wastewater within the system, thereby generating FGD scrubber purge continuously and at a much larger flow rate compared to plants that do recirculate the FGD water. However, based on the data collected from the Widows Creek sampling episode and the data collected during EPA's sampling program, the FGD scrubber purge that is generated in the once-through systems is at lower concentrations compared to plants that recirculate the water. While the concentrations are lower, the concentrations of the pollutants of concern are still at treatable levels for the FGD wastewater treatment system. Because of the larger flow rate associated with these systems, EPA evaluated costs for these plants to recirculate some of the FGD water back to the FGD system, as long as the materials of construction in the FGD system would be able to handle the buildup of additional chlorides. For more information on this analysis, see Section 4.4.3 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category Report*.

The air pollution controls operated upstream of the FGD system can also affect the pollutant concentrations in the FGD wastewater. For example, if a plant does not operate a particulate collection system (e.g., electrostatic precipitator, or ESP) upstream of the FGD system, the FGD system will act as the particulate control system and the FGD blowdown exiting the scrubber will contain fly ash and other particulates. As a result, the FGD wastewater will likely contain increased concentration of pollutants associated with the fly ash, such as arsenic and mercury. Based on responses to the Steam Electric Survey, EPA determined that there are approximately 15 to 25 coal- and petroleum coke-fired generating units that operate without a particulate collection system prior to the FGD system. EPRI collected data from a plant that has a generating unit with this configuration as well as a generating unit that operates an ESP prior to its FGD system. Using the data from the EPRI report representing the FGD influent from these two different units, EPA determined that the concentrations of mercury, nitrate/nitrite, and total suspended solids (TSS) are higher in FGD influent for the generating unit that operates the ESP; however the concentration of arsenic is higher for the unit without the ESP [EPRI, 1998a; EPRI, 1998b].[26] However, based on the information from the EPA sampling program, EPA determined that arsenic is treated to low levels in the technology selected as the proposed FGD wastewater treatment system, regardless of the influent concentrations entering the system.

Research conducted by EPA's Office of Research and Development (ORD) has observed that using postcombustion nitrogen oxide (NO_x) controls (e.g., selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR)) is correlated to an increased fraction of chromium in coal combustion residues (CCR) (including FGD wastes) being oxidized to hexavalent chromium (Cr^{+6}). Hexavalent chromium is a more soluble and more toxic form of chromium than the trivalent chromium (Cr^{+3}) usually measured in CCRs. This could explain why ORD has observed increased leachability of chromium when postcombustion NO_x controls are operating [U.S. EPA, 2008]. As part of EPA's sampling program, it collected samples from four plants operating SCRs at the time of the sampling episodes, one plant operating SNCRs at the time of the sampling episodes, and two plants that were not operating the SCR/SNCR at the time of the sampling episode. EPA compared the influent FGD wastewater characteristics from these plants to evaluate whether the operation of the NO_x control systems lead to higher concentrations of certain pollutants. EPA found that none of the plants had detectable concentrations of hexavalent chromium in the influent FGD wastewater samples, except for one of the plants that was not operating its SCR/SNCR. Additionally, EPA found that the concentrations of ammonia and nitrate/nitrite are not significantly different for the plants operating NO_x controls compared to the plants not operating NO_x controls.[27] While the ammonia and nitrate/nitrite concentrations were higher for some of the plants operating NO_x controls compared to the plants not operating NO_x controls, there were also plants operating NO_x controls that had lower concentrations of ammonia and nitrate/nitrite compared to plants not operating NO_x controls.

Table 6-2 summarizes the FGD wastewater discharged by the steam electric industry in 2009 as reported in the Steam Electric Survey. By January 1, 2014, 117 coal- and petroleum coke-fired plants will discharge FGD wastewater.[28] Collectively, these plants are expected to discharge 23.7 billion gallons of FGD wastewater per year, with an average total industry daily discharge of 65 MGD (0.6 MGD per plant). The amount of FGD wastewater discharged by the steam electric industry is less than the amount of blowdown generated by the industry, presented in Table 6-1, due to plants recycling the blowdown within the FGD scrubber as FGD preparation water and in other non-FGD plant processes. Table 6-2 also presents the distribution of FGD wastewater discharged based on type of coal used. Based on data from the Steam Electric Survey, the highest average discharge of FGD wastewater occurs from plants with FGD systems servicing units burning lignite coal.

[26] The EPRI report does not include data for selenium; therefore, EPA could not evaluate if the selenium concentrations are higher with or without an ESP. Regardless, the biological treatment system selected as the proposed FGD wastewater treatment technology is capable of removing selenium, even at high concentrations.

[27] EPA evaluated the ammonia and nitrate/nitrite concentrations because ammonia is injected into the flue gas as part of the operation of the SCR/SNCR operation; therefore, EPA had hypothesized that there might be higher concentrations of these pollutants in the FGD wastewater for plants operating these systems.

[28] By January 1, 2014, EPA estimates that there will be approximately 145 plants generating FGD wastewater from wet FGD systems; however, only 117 of these plants will discharge to a surface water or POTW.

Table 6-2. FGD Wastewater Discharge at Steam Electric Power Plants by January 1, 2014

	Number of Plants Discharging	Total Discharged FGD Wastewater Flow (gpd)	Average Discharged FGD Wastewater Flow (gpd/plant)
Total	117	65,000,000	559,000
Coal Type [a]			
Bituminous	68	41,000,000	600,000
Subbituminous	15-20	5,000,000	275,000
Lignite	1-5	4,000,000	800,000
Petroleum Coke	1-5	15,000	3,000
Blend [b]	23-28	15,400,000	620,000

Source: Steam Electric Survey, [ERG, 2013b].

Note: Wastewater flow rates are rounded to three significant figures.

Note: The FGD wastewater flow was estimated for 27 plants. Details on the methodology for estimating FGD wastewater flow rates are provided in EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (DCN SE01957).

a – Coal type classification is based on the types of coal burned in the units serviced by the wet FGD systems at each plant.

b – Plants operating wet FGD systems servicing units that burn two or more different coal types are classified as 'blend'.

EPA collected data as part of its sampling program, described in Section 3.4, to characterize the FGD wastewater from steam electric power plants. EPA's Office of Water (OW) also collected additional self-monitoring data from Duke Energy Carolinas' Belews Creek and Allen Steam Stations and Progress Energy Carolinas' Roxboro Steam Electric Plant. EPA used its sampling data and plant self-monitoring data to characterize the untreated FGD wastewater generated by the steam electric industry. Table 6-3 presents the average pollutant concentrations of the influent to the FGD wastewater treatment systems (i.e., downstream of the solids separation/solids dewatering processes). As shown in the table, FGD wastewater contains significant concentrations of chloride, total dissolved solids (TDS), nutrients, and metals, including bioaccumulative pollutants such as arsenic, mercury, and selenium. Some metals, such as boron, magnesium, manganese, and sodium, are largely present in the dissolved phase.

Table 6-3. Average Pollutant Concentrations in Untreated FGD Wastewater

Analyte	Unit	Average Total Concentration
Classicals		
Ammonia	mg/L	6.35
Nitrate Nitrite as N	mg/L	74.9
Nitrogen, Total Kjeldahl	mg/L	39.6
Biochemical Oxygen Demand	mg/L	9.38
Chemical Oxygen Demand	mg/L	367
Chloride	mg/L	7,740

Table 6-3. Average Pollutant Concentrations in Untreated FGD Wastewater

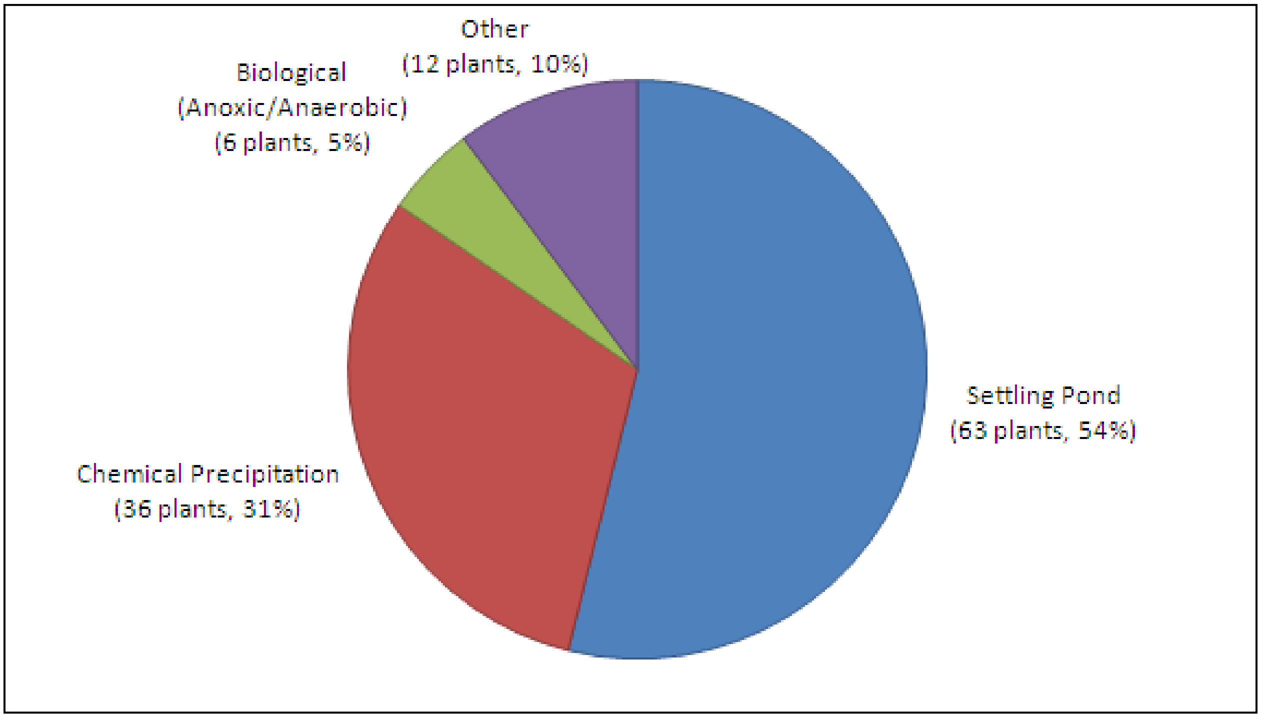
Analyte	Unit	Average Total Concentration	
Sulfate	mg/L	8,140	
Cyanide, Total	mg/L	0.764	
Total Dissolved Solids	mg/L	28,600	
Total Suspended Solids	mg/L	16,800	
Phosphorus, Total	mg/L	3.19	
Analyte	**Unit**	**Average Total Concentration**	**Average Dissolved Concentration**
Metals			
Aluminum	ug/L	332,000	37,200
Antimony	ug/L	22	6
Arsenic	ug/L	489	10
Barium	ug/L	2,850	321
Beryllium	ug/L	17	3
Boron	ug/L	291,000	266,000
Cadmium	ug/L	159	128
Calcium	ug/L	3,250,000	2,100,000
Chromium	ug/L	1,300	380
Chromium (VI)	ug/L	NA	5
Cobalt	ug/L	310	225
Copper	ug/L	784	88
Iron	ug/L	764	52,600
Lead	ug/L	323	6
Magnesium	ug/L	3,630,000	3,400,000
Manganese	ug/L	107,000	106,000
Mercury	ug/L	411	78
Molybdenum	ug/L	313	185
Nickel	ug/L	1,880	1,230
Selenium	ug/L	4,490	1,980
Silver	ug/L	9	1
Sodium	ug/L	275,000	265,000
Thallium	ug/L	27	16
Tin	ug/L	184	130
Titanium	ug/L	4,840	734
Vanadium	ug/L	1,450	18
Zinc	ug/L	5,380	2,290

Source: EPA Sampling Data, [ERG, 2012a – 2012g];Progress Energy Data, [NCDENR, 2011]; Duke Energy Data, [Duke Energy, 2011a-2011b].

NA – Not applicable. Samples were not analyzed for this particular analyte.

Note: Concentrations are rounded to three significant figures.

As indicated in Table 6-2, 117 plants discharge FGD wastewater. More than half (54 percent) of the 117 plants that discharge FGD wastewater use surface impoundments to treat the FGD wastewater prior to discharging it to a surface water or publicly owned treatment works (POTW). Surface impoundments are designed to remove particulates from wastewater by means of gravity. The use of more advanced wastewater treatment systems, such as chemical precipitation and biological treatment, is increasing to a limited extent due to more stringent effluent limit requirements some states have imposed on a site-specific basis. Figure 6-1 shows the distribution of FGD wastewater treatment systems currently used in the steam electric industry. All 117 steam electric power plants discharging FGD wastewater by January 1, 2014 are represented in the figure. Based on information provided in the Steam Electric Survey, EPA classified each plant's FGD wastewater treatment system based on the highest level of treatment into the following hierarchy: surface impoundment; any type of chemical precipitation system; a biological treatment system (either anoxic or anaerobic); or other.[29] Section 7 provides more detail on the variety of FGD wastewater treatment technologies currently used in the steam electric industry.



Source: Steam Electric Survey., [ERG, 2013b]

Figure 6-1. Distribution of FGD Wastewater Treatment Systems among the 117 Plants Discharging FGD Wastewater by January 1, 2014

[29] 'Other' refers to some level of FGD wastewater treatment beyond a surface impoundment, but not classified as either a chemical precipitation system or biological treatment systems. Those types of systems classified as 'other' include, but are not limited to, constructed wetlands, aerobic biological reactors, vapor-compression evaporation, ion exchange, and resin absorption.

6.2 ASH TRANSPORT WATER

As described in Section 4.3, plants often use water to remove fly and bottom ash from the particulate removal systems and boiler, respectively. This ash transport water can be reused as ash transport water or sent to treatment, typically in an on-site impoundment, and then discharged. This section presents an overview of the amount of fly ash and bottom ash transport water generated at coal-fired power plants within the steam electric industry. This section also discusses the characteristics of fly ash and bottom ash transport water and the amount of ash transport water that is discharged to surface water.

6.2.1 Fly Ash Transport Water

Fly ash transport water is one of the largest flows generated at coal-fired power plants. Many of the large baseload units generate enough fly ash that they operate fly ash transport water systems continuously, while some smaller units and peaking units typically generate less fly ash, and therefore, may operate fly ash transport water systems intermittently.[30,31] Table 6-4 presents the fly ash transport water flow rates generated by plants. The fly ash transport water flow rate is the flow rate of the fly ash transport water from the sluicing system to the impoundment, and does not necessarily represent the fly ash discharge flow rate from the plant. The industry generated 128 billion gallons of fly ash transport water in 2009, with the average plant generating 4.2 MGD.

Table 6-4. Fly Ash Transport Water Flow Rates

Flow Rate per Plant	Number of Plants[a]	Average Flow Rate	Median Flow Rate	Range of Flow Rate
gpm/plant	137	5,980	2,730	10 – 226,000
gpd/plant	137	4,230,000	2,140,000	4,000 – 35,700,000
gpy/plant	137	953,000,000	389,000,000	80,000 – 9,200,000,000

Source: Steam Electric Survey. [ERG, 2013b].

Note: Wastewater flow rates are rounded to three significant figures.

Note: The number of plants generating transport water are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a - A total of 141 plants wet sluiced fly ash in 2009. Four plants did not provide sufficient data to determine the plant-level fly ash transport water flow rate.

6.2.2 Bottom Ash Transport Water

Bottom ash transport water is an intermittent stream from steam electric units. The bottom ash transport water flow rates are typically not as large as the fly ash transport water flow rates. However, bottom ash transport water is still one of the larger volume wastestreams for steam electric power plants. Table 6-5 presents the bottom ash transport water flow rates

[30] A baseload unit is defined as a unit normally operating to produce electricity at an essentially constant rate. The unit will typically run for extended periods of time.

[31] A peaking unit is defined as a unit normally used only during peak-load periods of electricity demand or to replace the loss of another generating unit.

reported by the industry. The bottom ash transport water flow rate is the flow rate of the bottom ash transport water from the sluicing system to the impoundment, and does not necessarily represent the bottom ash discharge flow rate from the plant. While there are significantly more plants producing bottom ash transport water than those producing fly ash transport water, the average daily flow rate per plant is 40 percent less than the average fly ash transport water flow rate presented in Table 6-4. The industry generated 255 billion gallons of bottom ash transport water in 2009, with the average plant generating 2.5 MGD.

Table 6-5. Bottom Ash Transport Water Flow Rates

Flow Rate per Plant	Number of Plants[a]	Average Flow Rate	Median Flow Rate	Range of Flow Rate
gpm/plant	327	6,200	3,310	2 - 119,000
gpd/plant	328	2,490,000	1,020,000	3,200 – 34,600,000
gpy/plant	326	785,000,000	296,000,000	608,000 - 10,800,000,000

Source: Steam Electric Survey, [ERG, 2013b].

Note: Wastewater flow rates are rounded to three significant figures.

Note: The number of plants generating transport water are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

a – The number of plants listed indicate the total number of plants providing sufficient data to determine the bottom ash transport water flow rate. In 2009, 346 plants wet sluiced bottom ash but not all plants provided transport water flow rate information.

6.2.3 Ash Transport Water Characteristics

Fly ash and bottom ash transport water are typically treated in large surface impoundment systems. Plants operating both wet fly ash and wet bottom ash handling systems often commingle the two transport water streams, along with other wastestreams, within the same surface impoundment system. Plants operating only one wet ash handling system (e.g., fly ash or bottom ash, but typically bottom ash) may treat the ash transport water in surface impoundments, which often receive other plant wastewaters. Some plants recycle part or all of the impoundment effluent, but most plants discharge this impoundment overflow. Untreated ash transport waters contain significant concentrations of TSS and metals. The effluent from ash impoundments generally contains low concentrations of TSS; however, metals are still present in the wastewater, predominantly in dissolved form.

Impoundments are designed to remove particulates from wastewater by gravity. The fly ash, bottom ash, and other solids (e.g., FGD solids) settle out of the wastewater to the bottom of the impoundment. To accomplish this, the wastewater must reside in the impoundment long enough to settle the desired particle size. Impoundments can effectively reduce TSS in ash transport water, particularly bottom ash transport water, which contains relatively dense ash particles. Because impoundments remove solid particulates, they may also effectively remove some metals from fly ash transport water when the metals are present in suspended particulate form.

Impoundment overflow or discharge flow rates are not the same as ash transport water flow rates. The ash transport water flow rate is the flow rate of the transport water from the sluicing system to the impoundment, while the impoundment overflow or discharge flow is the flow rate of the water that is leaving the impoundment (e.g., discharged, recycled). Impoundments typically receive wastestreams in addition to bottom ash and fly ash (e.g., boiler blowdown, cooling water, low volume wastewater). In addition, there are factors acting to reduce the impoundment overflow rate, including impoundment losses from infiltration through the bottom of the impoundment or retaining dikes, evaporation, and amount of recycle from the impoundment back to the plant for reuse. Table 6-6 presents the amount of fly ash and bottom ash wastewater discharged in 2009, whereas Table 6-4 and Table 6-5 present the fly ash and bottom ash transport water generation flow rates. On average, a single plant discharges approximately 2.4 MGD of fly ash transport water and approximately 1.8 MGD of bottom ash transport water. Therefore, on average, the Steam Electric Category discharges approximately 57 percent of all fly ash transport water generated and 71 percent of all bottom ash transport water generated. Section 7 discusses various impoundment management practices in place in the industry.

Table 6-6. Ash Wastewater Discharge at Steam Electric Power Plants

Type of Wastewater	Number of Plants Discharging	Total Wastewater Discharged (2009, million gallons/year)	Average Wastewater Discharge Flow Rate (gpd/plant)
Fly Ash	95	81,100	2,390,000
Bottom Ash	245	157,000	1,760,000

Source: Steam Electric Survey, [ERG, 2013b].

Note: The number of plants and discharge flow rates in the steam electric industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

Note: 76 plants combine their fly and bottom ash sluice streams into one impoundment or impoundment system, identified as a combined ash impoundment. All 76 plants discharging combined ash wastewater were included in the table and counted as both fly ash and bottom ash dischargers. For these plants, a median percentage of total sluice flow for both fly and bottom ash sluice was calculated and used to calculate a fly and bottom ash contribution for all combined ash wastewater flows. The median fly ash wastewater contribution is 61.1 percent and the median bottom ash contribution is 38.9 percent.

Note: Wastewater flow rates are rounded to three significant figures.

The design, operation, and maintenance of impoundments in the steam electric industry varies by plant/company. As described above, impoundments are designed to remove TSS; therefore, the size of the impoundment depends upon the combined flow rate of the influent wastestreams, as well as the settling properties of the solids in the wastestreams. Some plants may add chemicals to the impoundments effluent to control the pH of the discharge. The current Steam Electric Power Generating ELGs limit the pH of discharged wastestreams to a range of 6.0 to 9.0 S.U. Common chemicals used to control the pH in impoundments are sodium hydroxide and hydrochloric acid.

EPA did not collect data representing fly ash or bottom ash transport water entering an impoundment during the sampling program for the rulemaking. However, during EPA's detailed study of the industry, EPA collected a wastewater sample representing the influent to a fly ash impoundment; the analytical results are presented in Table 4-18. Based on these samples, fly ash transport water contains significant concentration of metals, including arsenic, calcium, and titanium. Some metals are primarily present in the dissolved phase, such as boron, molybdenum, and selenium.

Table 6-7. Fly Ash Transport Water Characteristics

Analyte	Unit	Average Concentration	
Classicals			
Ammonia As Nitrogen (NH3-N)	mg/L	0.17	
Nitrate/Nitrite (NO3-N + NO2-N)	mg/L	2.65	
Total Kjeldahl Nitrogen (TKN)	mg/L	1.01	
Biochemical Oxygen Demand (BOD)	mg/L	ND (2.00)	
Chloride	mg/L	56.8	
Hexane Extractable Material (HEM)	mg/L	7.00	
Silica Gel Treated HEM (SGT-HEM)	mg/L	6.00	
Sulfate	mg/L	1,110	
Total Dissolved Solids (TDS)	mg/L	662	
Total Phosphorus	mg/L	4.03	
Total Suspended Solids (TSS)	mg/L	23,400	
Analyte	**Unit**	**Average Total Concentration**	**Average Dissolved Concentration**
Metals (EPA Method 200.7)			
Aluminum	µg/L	320,000	283
Antimony	µg/L	ND (81.2)	ND (20.0)
Arsenic	µg/L	1,520	86.8
Barium	µg/L	5,060	164
Beryllium	µg/L	71.5	ND (5.00)
Boron	µg/L	2,790	1,380
Cadmium	µg/L	39.6	ND (5.00)
Calcium	µg/L	204,000	94,800
Chromium	µg/L	1,300	ND (10.0)
Chromium (VI)	µg/L	NA	5.00
Cobalt	µg/L	381	ND (50.0)
Copper	µg/L	964	ND (10.0)
Iron	µg/L	298,000	ND (100)
Lead	µg/L	786	ND (50.0)
Magnesium	µg/L	35,100	15,200
Manganese	µg/L	1,120	40.3
Mercury	µg/L	2.31	ND (0.200)
Molybdenum	µg/L	333	243
Nickel	µg/L	739	ND (50.0)
Selenium	µg/L	ND (20.3)	16.6
Sodium	µg/L	69,900	64,400

Table 6-7. Fly Ash Transport Water Characteristics

Analyte	Unit	Average Concentration	
Thallium	µg/L	ND (40.6)	ND (10.0)
Titanium	µg/L	24,900	ND (10.0)
Vanadium	µg/L	2,340	70.7
Yttrium	µg/L	521	ND (5.00)
Zinc	µg/L	1,220	ND (10.0)
Metals (EPA Method 1638, 1631E)			
Antimony	µg/L	33.1	17.4
Arsenic	µg/L	519	80.7
Cadmium	µg/L	9.51	ND (1.00)
Chromium	µg/L	569	ND (80.0)
Chromium (VI)	µg/L	NA	NA
Copper	µg/L	719	ND (20.0)
Lead	µg/L	260	ND (0.500)
Mercury	µg/L	1.16	0.00055
Nickel	µg/L	291	ND (100)
Selenium	µg/L	ND (200)	21.2
Thallium	µg/L	43.6	3.1
Zinc	µg/L	720	ND (50.0)

Source: Cardinal SER, [ERG, 2008].

NA – Not applicable. No data for this analyte were available specific to the impoundment type.

ND – Not detected (number in parenthesis is the reporting limit). The sampling episode report for the plant contains additional sampling information, including analytical results for analytes measured above the detection limit, but below the reporting limit (i.e., J-values).

Note: Concentrations are rounded to three significant figures.

6.3 COMBUSTION RESIDUAL LANDFILL AND IMPOUNDMENT LEACHATE

As discussed earlier, plants generating FGD wastewater and ash transport water generally send the wastewater to a surface impoundment or wastewater treatment system. Solids resulting from FGD wastewater treatment system are typically transferred to a landfill for disposal. The FGD solids and ash sent to the surface impoundments may be stored permanently in the impoundment or dredged from the impoundment and transferred to a landfill. Additionally, plants may place dry ash, both fly ash and bottom ash, and FGD residuals (i.e., gypsum or calcium sulfite) in a landfill. These combustion residuals stored in the landfills and impoundments can contaminate the water that contacts the residuals in these management units. As discussed in Section 4.3.5, leachate is the liquid that drains or leaches from a landfill or impoundment. Leachate, which includes contaminated stormwater, that has come into contact with combustion residual solids deposited in an impoundment or a landfill, contains heavy metals and other contaminants. The following section describes the amount of leachate estimated to be generated by the steam electric industry and the characteristics of these wastestreams.

EPA's Steam Electric Survey included a section, Part F, that requested information on the management practices of both impoundments and landfills containing combustion residuals. Part F of the survey included questions related to the collection and treatment of leachate from both types of management units. As described in Section 3.3, EPA sent Part F only to a statistically sampled stratum of coal- and petroleum coke-fired plants (97 plants). EPA used the responses to Part F of the survey along with the appropriate survey weights for Part F to estimate the number of plants in the industry generating leachate from impoundments and landfills containing combustion residuals. Table 6-8 presents the estimated number of plants generating leachate in the steam electric industry from either an impoundment or a landfill. Based on the reported leachate generation rates and the survey weights for Part F, EPA estimates that the steam electric industry generates approximately 6.6 billion gpy of combined impoundment and landfill leachate.

Table 6-8. Leachate Generation in the Steam Electric Industry

Type of Wastewater	Management Unit Status	Number of Plants	Total Wastewater Generated (2009, million gallons/year)	Average Wastewater Generation Rate (gpd/plant)
Total Landfill Leachate [a]	**Total**	**92 [b]**	**2,210**	**60,400**
	Active/Inactive	84	2,200	65,500
	Planned	1	2	6,220
	Retired	5-10	17	5,950
Total Impoundment Leachate [c]	**Total**	**66**	**4,000**	**236,000**

Source: Steam Electric Survey, [ERG, 2013b].

Note: Wastewater flow rates are rounded to three significant figures.

Note: Part F of the Steam Electric Survey was distributed to 97 plants. The responses from these plants were weighted to reflect the portion of plants generating leachate in the industry. Weighted, these 97 plants represent 384 coal- and petroleum coke-fired stream electric plants.

Note: The number of plants generating leachate are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.Note: For presentation purposes, EPA used leachate generation from the Steam Electric Survey reported in gpy to calculate the total wastewater generated in 2009. Leachate flow can fluctuate significantly from day to day based on rainfall; therefore, EPA believes it is more appropriate to use the values estimated by the plants instead of using the average gpd and number of days generating leachate to calculate the yearly flow. To calculate the average wastewater generation rate, EPA used leachate generation reported in gpd as a rough estimate of the average leachate generation per day.

a – Eighteen (18) plants reported operating a leachate collection system but did not provide the amount of leachate collected in 2009. These plants are not included in the number of plants or used when calculating the average wastewater generated in Table 6-8.

b – The number of plants in each landfill status category is not additive. Some plants may operate more than one landfill, each with a different status (active/inactive, retired, or planned).

c – Nine plants reported operating a leachate collection system but did not provide the amount of leachate collected in 2009. These plants are not included in the number of plants or used when calculating the average wastewater generated in Table 6-8. All impoundment leachate reported in the survey is from active/inactive impoundments (i.e., plants did not report leachate from closed/retired impoundments).

The leachate collected from impoundments/landfills is generally transferred to a collection impoundment. The effluent from these collection impoundments can be discharged, sent to a holding impoundment, or sent to further treatment such as a constructed wetland system. Only a small percentage of the leachate collected from combustion residual impoundments/landfills is treated by means other than a surface impoundment: 9 percent of impoundment leachate and 24 percent of landfill leachate. Section 7.4 provides more detail on the types of leachate treatment technologies [ERG, 2013b].

As discussed previously in Section 4.3.5, nearly 50 percent of impoundment leachate generated in the industry is returned directly to the impoundment (or recycled within the plant). An additional 9 percent is treated on site in some fashion prior to being discharged. Forty-one percent of plants discharge leachate from impoundments without any further treatment.

The majority of landfill leachate is discharged to surface water without prior treatment (68 percent of landfills generating leachate). As shown in Table 4-15, the remaining 32 percent of landfills return the leachate back to the landfill or treat the leachate on site prior to discharge. Table 6-9 presents the number of coal- and petroleum coke-fired plants that discharging landfill leachate in 2009. The table separates the amount of leachate discharged by active or inactive landfills from the amount discharged by retired landfills. Data from the Steam Electric Survey indicate a significant difference between the amount of leachate discharged by landfills classified as active or inactive and the amount discharged by landfills classified as retired. The survey defined a retired landfill as a landfill that will never accept additional waste and an inactive landfill as a landfill that is currently not receiving waste, but might in the future. Retired landfills likely discharge less leachate compared to active and inactive landfills because many retired landfills are partially or completely capped/covered, thereby reducing the amount of precipitation entering the landfill.

Table 6-9. Landfill Leachate Discharged by Coal- and Petroleum Coke-Fired Power Plants in 2009

Type of Wastewater	Number of Plants	Total Wastewater Discharged (2009, million gallons/year)	Average Wastewater Flow Rate (gpd/plant)
Active/Inactive Landfill Leachate	100-105	2,200	54,000
Retired Landfill Leachate	5-10	17	6,180

Source: Steam Electric Survey, [ERG, 2013b].

Note: Ranges are provided to protect CBI data. Wastewater flow rates are rounded to three significant figures.

Note: The number of plants and discharge flow rates in the steam electric industry are based on values reported in the Steam Electric Survey, which were scaled to represent the industry as a whole using the industry-weighting factors discussed in Section 3.3.

As part of the Steam Electric Survey, EPA requested that a subset of plants provide sampling data for leachate collected at the plant. EPA used these data to characterize the untreated landfill leachate discharged by the steam electric industry. In response to the survey, EPA obtained sampling data from 22 active fuel combustion residual landfills, four inactive fuel combustion residual landfills, and seven retired landfills. Table 6-10 presents the average pollutant concentration for each type of landfill. Combustion residual landfill leachate contains high concentration of metals, such as boron, calcium, chloride, and sodium, similar to FGD and ash wastewaters. The metals in the leachate are generally at lower concentrations than those seen in FGD wastewater and ash transport water, but still at treatable levels above the quantitation limit. As expected, the leachate from active landfills generally has larger concentrations of metals compared to inactive and retired landfills.

Table 6-10. Untreated Landfill Leachate Concentrations

Analyte	Units	Untreated Active Landfill Concentration	Untreated Inactive Landfill Concentration	Untreated Retired Landfill Concentration
Classicals				
Chloride	ug/L	542,000	11,100	149,000
Sulfate	ug/L	1,910,000	1,070,000	881,000
TDS	ug/L	3,860,000	1,670,000	1,660,000
TSS	ug/L	41,400	4,210	13,800
Metals				
Aluminum	ug/L	5,030	100	87
Antimony	ug/L	4.6	4.9	1.1
Arsenic	ug/L	46	10	41
Barium	ug/L	57	50	37
Beryllium	ug/L	1.9	0.47	1.1
Boron	ug/L	20,500	3,640	10,100
Cadmium	ug/L	2.7	1.9	0.73
Calcium	ug/L	481,000	386,000	303,000
Chromium	ug/L	4.9	1.6	3.4
Cobalt	ug/L	84	3.8	7.6
Copper	ug/L	10	1.7	2.4
Iron	ug/L	59,000	95	5,700
Lead	ug/L	1.4	0.47	0.83
Magnesium	ug/L	115,000	33,700	21,800
Manganese	ug/L	4,360	355	1,280
Mercury	ug/L	1.4	0.01	13
Molybdenum	ug/L	1,880	995	702
Nickel	ug/L	69	43	16
Selenium	ug/L	74	84	46
Silver	ug/L	0.68	0.42	1.03
Sodium	ug/L	327,000	16,700	66,200
Thallium	ug/L	1.3	0.96	0.92
Tin	ug/L	11	13	33
Titanium	ug/L	17	15	11
Vanadium	ug/L	3,240	6.2	69

Table 6-10. Untreated Landfill Leachate Concentrations

Analyte	Units	Untreated Active Landfill Concentration	Untreated Inactive Landfill Concentration	Untreated Retired Landfill Concentration
Zinc	ug/L	154	58	38

Source: Steam Electric Survey, [ERG, 2013b].

Note: Concentrations are rounded to three significant figures.

In response to the survey, EPA obtained sampling data from 20 leachate impoundments. Table 6-11 presents the average pollutant concentration for the 20 impoundments. Combustion residual impoundment leachate contains high concentrations of metals, such as calcium, chloride, and sodium, similar to FGD and ash wastewaters. The metals present in the leachate are generally at lower concentrations than those seen in FGD wastewater and ash transport water, but still at treatable levels above the quantitation limit.

Table 6-11. Untreated Impoundment Leachate Concentrations

Analyte	Units	Average Untreated Impoundment Concentration
Classicals		
Chloride	ug/L	251,000
Sulfate	ug/L	1,242,000
Total Dissolved Solids	ug/L	2,380,000
Total Suspended Solids	ug/L	9,230
METALS		
Aluminum	ug/L	213
Antimony	ug/L	0.96
Arsenic	ug/L	20
Barium	ug/L	55
Beryllium	ug/L	0.51
Boron	ug/L	22,800
Cadmium	ug/L	5.1
Calcium	ug/L	291,000
Chromium	ug/L	1.8
Cobalt	ug/L	8.1
Copper	ug/L	2.7
Iron	ug/L	7,070
Lead	ug/L	0.51
Magnesium	ug/L	123,000
Manganese	ug/L	2,170
Mercury	ug/L	0.19
Molybdenum	ug/L	208
Nickel	ug/L	21
Selenium	ug/L	152

Table 6-11. Untreated Impoundment Leachate Concentrations

Analyte	Units	Average Untreated Impoundment Concentration
Silver	ug/L	0.63
Sodium	ug/L	145,000
Thallium	ug/L	0.67
Tin	ug/L	105
Titanium	ug/L	7.1
Vanadium	ug/L	3.9
Zinc	ug/L	301

Source: Steam Electric Survey, [ERG, 2013b].

Note: Concentrations are rounded to three significant figures.

6.4 FLUE GAS MERCURY CONTROL WASTEWATER

As described in Section 4.3.4, there are two types of systems used for FGMC: addition of oxidizers to the coal prior to combustion and injection of activated carbon into the flue gas, after combustion. Adding the oxidizers does not generate a new wastewater stream, but it may increase the concentration of mercury in the FGD wastewater because the oxidized mercury is more easily removed by the FGD system. Activated carbon injection (ACI) systems, however, have the potential to generate a new wastestream, depending on the location of the injection. If the injection occurs upstream of the primary particulate removal system, then the mercury-containing carbon (i.e., FGMC waste) will be collected and handled the same way as the fly ash; therefore, if the fly ash is wet sluiced, then the FGMC wastes are also wet sluiced. When the activated carbon is injected downstream of the primary particulate removal system, the FGMC waste must be collected in a separate particulate removal system, typically a fabric filter baghouse. Residual fly ash that passes through the primary particulate removal system may also be captured.

The FGMC waste/fly ash can either be handled using a wet sluicing system or handled in a dry fashion. There are 15 plants with at least one ACI system injecting carbon downstream of the primary particulate removal system. Six of these plants identified the FGMC system as planned, with an installation date after 2009. Of these fifteen plants, only one plant plans to handle the FGMC waste using a wet sluicing system; however, this plant will send the FGMC transport water to a zero discharge impoundment, where the impoundment overflow will be reused for fly ash, bottom ash, and FGMC transport water. EPA does not have any sampling data on wastewater characteristics of the FGMC transport water or the characteristics of FGMC waste [ERG, 2013b].

For ACI systems in which the carbon is injected upstream of the primary particulate control system, the FGMC waste is collected with fly ash. Again, this can be handled either wet or dry, depending on how the plant is handling the fly ash. There are 58 plants with at least one ACI system injecting carbon upstream of the primary particulate system. Fourteen of these plants identified the FGMC system as planned, with an installation date after 2009. Of these 58 plants, five (three with current systems and two with planned systems) reported handling the FGMC waste using a wet sluicing system. EPA does not have any sampling data on the wastewater characteristics of the FGMC transport water associated with these wet systems; however, ORD evaluated the effects of these ACI systems on the characteristics of fly ash and determined that these systems substantially increase the total mercury content of the fly ash [U.S. EPA, 2006]. EPA does not have any sampling data demonstrating how the added mercury in the fly ash affects the characteristics of the fly ash transport water.

ORD looked at six plants, four operating ACI systems and two operating brominated ACI systems.[32] ORD collected fly ash from these plants, with and without FGMC waste, and analyzed the fly ash for mercury, arsenic, and selenium. ORD concluded that, of the three constituents analyzed, FGMC waste significantly affects only the mercury concentration of fly ash. Five of the six plants showed an increase in the mercury concentration of fly ash with FGMC waste as compared to fly ash alone [U.S. EPA, 2006]. Table 6-12 shows the distribution of mercury concentrations at each of the six plants.

Table 6-12. Mercury Concentrations in Fly Ash with and without ACI Systems

Plant	Mercury (EPA Method 3052)			Mercury (EPA Method 7473)		
	Fly Ash Only (ng/g)	With ACI (ng/g)	Percent Increase	Fly Ash Only (ng/g)	With ACI (ng/g)	Percent Increase
Brayton Point	651	1,530	135%	582	1,414	143%
Pleasant Prairie	158	1,180	648%	147	1,177	701%
Salem Harbor	529	412	-22%	574	454	-21%
Facility C	16	1,151	7,094%	11	1,090	9,810%
St. Clair [a]	111	1,163	949%	NT	NT	NA
Facility L (Run 1) [a]	13	38	190%	NT	NT	NA
Facility L (Run 2) [a]	20	71	252%	NT	NT	NA

Source: [U.S. EPA, 2006]

Note: ORD analyzed mercury using two different analytical methods, EPA Method 3052 and EPA Method 7473. Both results are shown in the table.

NT – Not tested.

NA – Not applicable.

a – Plant operates a brominated activated carbon injection system.

6.5 GASIFICATION WASTEWATER

As discussed in Section 4.3.6, the gasification process creates a number of different wastewater streams, some of which are specific to the integrated gasification combined cycle (IGCC) process (e.g., air separation unit blowdown) and others that are similar to general power plant wastewaters (e.g., cooling water). The IGCC-specific wastewaters are generally combined, sometimes along with other plant wastewaters, and collectively referred to as grey water or sour water. The sour water is sent to a steam stripper, sometimes called a sour water treatment unit, which essentially distills the wastewater and produces a sweet water stream and recycle slurry

[32] The chloride content of flue gas can affect the performance of activated carbon systems, low chloride concentrations can yield low mercury removal. Some plants with low chloride levels utilize brominated activated carbon as a sorbent to increase the amount of mercury captured [U.S. EPA, 2006].

stream that is reused in slurry preparation. Figure 4-4 depicts the general process flow diagram for the IGCC process. Although it has been treated by steam stripping, the sweet water stream is still contaminated with elements from the gasification process, such as selenium, chromium, and arsenic. The sweet water may also be contaminated with various other metals formed in the gasification unit, such as selenocyanate. These metals are not known to be generated in traditional coal-fired boilers.

EPA collected data as part of the CWA 308 monitoring program described in Section 3.4.1 from two plants operating IGCC systems. Both plants, Tampa Electric Company's Polk Station (Polk) and Wabash Valley Power Association's Wabash River Station (Wabash River), treat their gasification wastewater with a vapor-compression evaporation system. Both plants sampled the influent streams transferred to the vapor-compression evaporation system and the distillate/condensate(s) from the systems. EPA used the data from both plants to characterize untreated gasification wastewater. Table 6-13 presents the average concentrations of the untreated gasification wastewater. The table provides the individual average concentrations for the two plants, as well as the average for both plants combined. For both plants, the gasification wastewater represents a combination of multiple wastestreams, but because the plants operate slightly different processes, they are not the same wastestreams at both plants.

Table 6-13. Untreated Gasification Wastewater Concentrations

Analyte	Units	Polk Concentration	Wabash River Concentration	Average Polk and Wabash River Concentration
Classicals				
Ammonia	mg/L	175	35	105
Nitrate Nitrite as N	mg/L	0.09	0.05	0.07
Nitrogen, Kjeldahl	mg/L	603	65	334
Biochemical Oxygen Demand	mg/L	7.7	205	106
Chemical Oxygen Demand	mg/L	101	823	462
Chloride	mg/L	1,300	1,050	1,175
Sulfate	mg/L	2,750	11	1,380
Total Dissolved Solids	mg/L	4,575	4,225	4,400
Total Suspended Solids	mg/L	16	2.0	8.9
Phosphorus, Total	mg/L	0.47	0.19	0.33
Metals				
Aluminum	ug/L	11,475	100	5,788
Antimony	ug/L	363	1.0	182
Arsenic	ug/L	280	4	142
Barium	ug/L	118	10	64
Beryllium	ug/L	14	1.0	7.3
Boron	ug/L	38,250	34,750	36,500
Cadmium	ug/L	4.1	2.0	3.0
Calcium	ug/L	19,450	783	10,116
Chromium	ug/L	4.0	4.0	4.0

Table 6-13. Untreated Gasification Wastewater Concentrations

Analyte	Units	Polk Concentration	Wabash River Concentration	Average Polk and Wabash River Concentration
Cobalt	ug/L	10	10	10
Copper	ug/L	2.0	2.0	2.0
Cyanide, Total	mg/L	1.4	2.3	1.8
Iron	ug/L	2,115	1,140	1,628
Lead	ug/L	18	1.0	10
Magnesium	ug/L	5,325	200	2,763
Manganese	ug/L	238	10	124
Mercury	ng/L	70	4.3	37
Molybdenum	ug/L	49	20	35
Nickel	ug/L	4,950	2.0	2,476
Selenium	ug/L	1,278	920	1,099
Silver	ug/L	1.0	1.0	1.0
Sodium	ug/L	1,675,000	1,850,000	1,762,500
Thallium	ug/L	254	3	129
Tin	ug/L	100	100	100
Titanium	ug/L	19	10	15
Vanadium	ug/L	280	16	148
Zinc	ug/L	77	20	49

Source: CWA 308 Monitoring Data, [ERG, 2012h].

6.6 METAL CLEANING WASTE

As discussed in Section 4.3.7, metal cleaning wastes are generated during the cleaning of metal process equipment and can consist of chemical and non-chemical cleaning operations. There are several different types of metal cleaning wastes (identified in Section 4.3.7) and the frequency of generation varies among the different types of metal cleaning wastes. Table 6-14 presents the minimum, median, and maximum frequency of the generation for each of the metal cleaning wastes, broken out between chemical and nonchemical operations. Air heater cleaning and soot blowing are both examples of cleaning activities that do not use chemicals; between 98 and 100 percent of all units conducting these cleaning operations use no chemicals during the cleaning operations.[33] Boiler tube cleaning generally involves the addition of chemicals and typically occurs less often than once a year. Fifty-nine percent of the units identified as conducting boiler tube cleaning do so once every 10 or more years.

EPA compared the frequency information reported in the Steam Electric Survey to data included in the 1974 Technical Development Document (TDD) to determine if the industry has

[33] From the responses to the Steam Electric Survey, EPA determined that 98 percent of units conducting air heater cleaning operations and 100 percent of units blowing soot (that use water) do not use chemical addition in the cleaning process.

changed the frequency with which they conduct metal cleaning operations. The 1974 TDD contains frequency information for three metal cleaning operations: air heater cleaning, boiler fireside cleaning, and boiler tube cleaning. For air heater cleaning, the 1974 TDD frequency data ranges from once per month to four times per year, which is generally more frequent compared to the data from the Steam Electric Survey. For boiler fireside cleaning, the 1974 TDD frequency data ranges from eight times per year to twice per year, which is comparable to the frequency data from the Steam Electric Survey. For boiler tube cleaning, the 1974 TDD frequency data ranges from twice per year to once every eight years, which is also comparable to the frequency data from the Steam Electric Survey. Therefore, EPA determined that the industry is still performing these cleaning operations at a similar frequency compared to when the Agency initially set the BPT standards for metal cleaning wastes.

In addition to frequency, the volume of wastewater generated also varies among the different types of metal cleaning wastes. Table 6-15 provides the minimum and maximum flow rates associated with each of these cleaning operations. The 1974 TDD contains flow rate information for air heater cleaning, boiler fireside cleaning, and boiler tube cleaning. For air heater cleaning, the 1974 TDD flow rates ranges from 43,000 to 600,000 gallons per event, which is within the range reported in the Steam Electric Survey. For boiler fireside cleaning, the 1974 TDD flow rate data ranges from 24,000 to 720,000 gallons/event, which is within the range reported in the Steam Electric Survey. For boiler tube cleaning, the 1974 TDD flow rate data ranges from 13,900 to 150,000 gallons/event, which is also within the range reported in the Steam Electric Survey. While all of these are within the ranges reported in the Steam Electric Survey, EPA noted that the maximum value reported in the Steam Electric Survey was significantly higher (i.e., an order of magnitude) for each of these cleaning operations. However, based on these results, EPA found that the industry is still generating similar quantities of wastewater from these cleaning operations compared to when the Agency initially set the BPT standards for metal cleaning wastes.

The 1974 and 1982 TDD contain characterization data for metal cleaning wastewaters. Tables A-V-5, A-V-6, and A-V-20 in the 1974 TDD contain characterization data associated with boiler tube cleaning, air preheater cleaning, and boiler fireside cleaning [U.S. EPA, 1974]. Tables V-68 through V-73 in the 1982 TDD contain characterization data and wastewater flow rate data boiler fireside and air preheater cleaning [U.S. EPA, 1982].

Table 6-14. Metal Cleaning Waste Generation Frequency Reported in the Steam Electric Survey

Type of Wastestream	Minimum Frequency (i.e., Least Frequent)	Median Frequency	Maximum Frequency (i.e., Most Frequent)
Nonchemical Cleaning Operations			
Air Compressor Cleaning	NA	NA	NA
Air-Cooled Condenser Cleaning	[a]	[a]	[a]
Air Heater Cleaning	Once Every 40 Years	Once Every Year	11 Times Every Day
Boiler Fireside Cleaning	Once Every 30 Years	Once Every Year	Twice Every Day
Boiler Tube Cleaning	Once Every 10 Years	Once Every 1-2 Years	Twice Every Year

Table 6-14. Metal Cleaning Waste Generation Frequency Reported in the Steam Electric Survey

Type of Wastestream	Minimum Frequency (i.e., Least Frequent)	Median Frequency	Maximum Frequency (i.e., Most Frequent)
Combustion Turbine Cleaning (Combustion)	Twice Every Year	Once Every Three Days	Once Every Two Days
Combustion Turbine Cleaning (Compressor)	Once Every Year	Once Every Two Days	2-3 Times Every Day
Condenser Cleaning	[a]	Once Every Year	Once Every Year
Draft Fan Cleaning	Once Every Four Years	Once Every Year	Once Every Year
Economizer Cleaning	Once Every 50 Years	Once Every Three years	Once Every Year
FGD Equipment Cleaning	[a]	[a]	Once Every Day
Heat Recovery Steam Generator Cleaning	NA	NA	NA
Mechanical Dust Collector Cleaning	Once Every 10 Years	Once Every Four Years	Once Every Year
Nuclear Steam Generator Cleaning	NA	NA	NA
Precipitator Wash	Once Every 10 Years	Once Every Three Years	Once Every Year
SCR Catalyst Soot Blowing	Three Times Every Year	Three Times Every Year	Three Times Every Year
Sludge Lancing	Once Every 4-5 Years	Once Every Three Years	Once Every 1-2 Years
Soot Blowing	Once Every 10 Years	Once Every Day	600 Times Every Day
Steam Turbine Cleaning	Once Every 10 Years	Once Every 7 Years	Three Times Every Year
Superheater Cleaning	NA	NA	NA
Chemical Cleaning Operations			
Air Compressor Cleaning	Twice Every Year	Twice Every Year	Twice Every Year
Air-Cooled Condenser Cleaning	NA	NA	NA
Air Heater Cleaning	Once Every Two Years	Twice Every Month	Twice Every Month
Boiler Fireside Cleaning	Once Every 10 Years	[a]	[a]
Boiler Tube Cleaning	Once Every 50 Years	Once Every 10 Years	Once Every Two Years
Combustion Turbine Cleaning (Combustion)	Once Every 8 Years	Twice Every Year	Three Times Every Month
Combustion Turbine Cleaning (Compressor)	Once Every 10 Years	Twice Every Year	Once Every Two Days
Condenser Cleaning	Once Every 30 Years	Once Every 25 Years	[a]
Draft Fan Cleaning	Once Every 3-4 Years	Once Every 3-4 Years	Once Every 3-4 Years
Economizer Cleaning	NA	NA	NA
FGD Equipment Cleaning	Once Every Day	Once Every Day	Once Every Day
Heat Recovery Steam Generator Cleaning	Once Every 40 Years	Once Every 40 Years	Once Every 10 Years
Mechanical Dust Collector Cleaning	NA	NA	NA
Nuclear Steam Generator Cleaning	[a]	[a]	[a]
Precipitator Wash	NA	NA	NA
SCR Catalyst Soot Blowing	NA	NA	NA
Sludge Lancing	NA	NA	NA

Table 6-14. Metal Cleaning Waste Generation Frequency Reported in the Steam Electric Survey

Type of Wastestream	Minimum Frequency (i.e., Least Frequent)	Median Frequency	Maximum Frequency (i.e., Most Frequent)
Soot Blowing	NA	NA	NA
Steam Turbine Cleaning	Once Every 30 Years	Once Every Four Years	Once Every Year
Superheater Cleaning	Once Every 37 Years	Once Every 37 Years	Once Every 37 Years

Source: Steam Electric Survey, [ERG, 2013b].

Note: This table presents data gathered from only the subset of plants that were required to complete Part E of the survey.

NA – Not applicable. The cleaning operation was not reported in the Steam Electric Survey for the type of chemical usage (i.e., nonchemical or chemical cleaning).

a – Data were removed from certain cells to protect the release of information claimed confidential business information.

Table 6-15. Metal Cleaning Wastewater Flow Rates Reported in the Steam Electric Survey

Type of Wastestream	Minimum Flow (Gallons per Event)	Maximum Flow (Gallons per Event)
Nonchemical Cleaning Operations		
Air Compressor Cleaning	NA	NA
Air-Cooled Condenser Cleaning	[a]	[a]
Air Heater Cleaning	0	8,000,000
Boiler Fireside Cleaning	0	4,500,000
Boiler Tube Cleaning	0	250,000
Combustion Turbine Cleaning (Combustion)	0	1,800
Combustion Turbine Cleaning (Compressor)	0	5,000
Condenser Cleaning	4,800	[a]
Draft Fan Cleaning	5,000	169,000
Economizer Cleaning	5,000	2,640,000
FGD Equipment Cleaning	15	[a]
Heat Recovery Steam Generator Cleaning	NA	NA
Mechanical Dust Collector Cleaning	180,000	3,000,000
Nuclear Steam Generator Cleaning	NA	NA
Precipitator Wash	9,000	16,800,000
SCR Catalyst Soot Blowing	11,900	11,900
Sludge Lancing	0	800
Soot Blowing	0	200,000
Steam Turbine Cleaning	0	2,000,000
Superheater Cleaning	NA	NA
Chemical Cleaning Operations		

Table 6-15. Metal Cleaning Wastewater Flow Rates Reported in the Steam Electric Survey

Type of Wastestream	Minimum Flow (Gallons per Event)	Maximum Flow (Gallons per Event)
Air Compressor Cleaning	20	20
Air-Cooled Condenser Cleaning	NA	NA
Air Heater Cleaning	2,700	80,000
Boiler Fireside Cleaning	0	50,000
Boiler Tube Cleaning	0	2,000,000
Combustion Turbine Cleaning (Combustion)	0	11,000
Combustion Turbine Cleaning (Compressor)	0	10,000
Condenser Cleaning	25,000	[a]
Draft Fan Cleaning	100	100
Economizer Cleaning	NA	NA
FGD Equipment Cleaning	10	15
Heat Recovery Steam Generator Cleaning	0	231,000
Mechanical Dust Collector Cleaning	NA	NA
Nuclear Steam Generator Cleaning	[a]	[a]
Precipitator Wash	NA	NA
SCR Catalyst Soot Blowing	NA	NA
Sludge Lancing	NA	NA
Soot Blowing	NA	NA
Steam Turbine Cleaning	1,500	20,000
Superheater Cleaning	39,000	39,000

Source: Steam Electric Survey, [ERG, 2013b].

Note: This table presents data gathered from only the subset of plants that were required to complete Part E of the survey.

NA – Not applicable. The cleaning operation was not reported in the Steam Electric Survey for the type of chemical usage (i.e., nonchemical or chemical cleaning).

a – Data were removed from certain cells to protect the release of information claimed confidential business information.

6.7 IDENTIFICATION OF POLLUTANTS OF CONCERN

Constituents present in combustion wastewater are primarily derived from the parent carbon feedstock (e.g., coal, petroleum coke). A number of these constituents have the potential to cause environmental harm depending on the mass pollutant loadings, wastewater concentration, and how organisms are exposed to them in the environment. EPA conducted a field sampling program as part of the detailed study and rulemaking efforts for the Steam Electric Power Generating ELGs to characterize the wastewater generated by the industry. The analytes selected for analysis reflect EPA's current understanding of power plant wastewaters, including contributions from scrubber sorbents, treatment chemicals, and other sources. Section 3.4.1 discusses the analytes evaluated in the EPA sampling program.

EPA primarily used the analytical data from the sampling episodes to identify the pollutants of concern (POCs) considered for this rulemaking. From the list of analytes sampled, EPA eliminated from consideration all pollutants that were never detected in untreated wastewater samples. EPA then reviewed its data from untreated wastewater samples from individual wastestreams to identify pollutants detected at greater than or equal to 10 times the baseline value in at least 10 percent of all untreated process wastewater samples.[34] This criterion ensures that the pollutant was present in sufficient concentrations at sites where EPA evaluated treatment performance. This is used as a screening tool to identify those pollutants that are quantified in a wastestream at sufficient frequency and at treatable levels. Using 10 times the baseline value as a screening threshold can facilitate evaluations of treatment system performance and efficacy, since it ensures the influent concentrations are high enough to more readily quantify the degree of pollutant removal resulting from treatment processes such as chemical or biological removal. However, the criterion is less applicable in cases where the technology basis results in complete removal of all pollutants present, such as would occur under the technology options considered for fly ash transport water, bottom ash transport water, and FGMC wastewater. For these “zero discharge” technologies, confirmation that a pollutant is present in the wastestream at quantifiable levels may be sufficient to identify a pollutant as a pollutant of concern. Additionally, in past effluent guidelines rulemakings, EPA has determined that a lower threshold (e.g., 5 times the baseline value) was the appropriate criterion for identifying pollutants of concern. For example, see Section 7 of the Technical Development Document for the Final Effluent Limitations Guidelines and Standards for the Meat and Poultry Products Point Source Category (40 CFR 432) (EPA-821-R-04-011).

EPA used the baseline values that were developed for the 2000 Centralized Waste Treatment (CWT) Industry Effluent Limitations Guidelines for this analysis. The baseline values are generally equal to the nominal quantitation limit identified for the analytical method for a pollutant. For the CWT ELGs, the Agency made several exceptions to this general rule if it determined that reliable measurements of a pollutant could be made at a lower level, or if the nominal quantitation limit could not be reasonably achieved, or if a single baseline value had to be selected when a pollutant had multiple nominal quantitation limits. Generally, the CWT ELGs used the instrument detection limit for EPA Method 1620 as the basis for the metals baseline values, with some exceptions. For the steam electric proposed ELGs, EPA analyzed the samples using EPA Methods 200.7, 200.8 with collision cell, and 1631E. Each of these methods are capable of achieving quantitation limits that are lower than the baseline values from CWT. However, EPA used the CWT baseline values, in most cases, as a more conservative value for the analysis. EPA did make a couple of exceptions and used the minimum level for mercury defined in EPA Method 1631E (i.e., 0.5 ng/L). Additionally, EPA used 2.0 μg/l for arsenic, which is based on a method detection limit study conducted by EPA [CSC, 2013]. Table 6-16 presents the baseline values used for the identification of POCs associated with the proposed Steam Electric ELGs.

[34] This approach is consistent with the process EPA used to identify pollutants of concern for many categories. EPA takes this approach to ensure the pollutants are present at treatable levels.

Table 6-16. Baseline Values for Steam Electric Industry POCs

Analyte	Unit	Baseline Value
Classicals or Conventionals		
Ammonia as Nitrogen	µg/l	50.0
Biochemical Oxygen Demand	µg/l	2,000.0
Chemical Oxygen Demand	µg/l	5,000.0
Chloride	µg/l	1,000.0
Nitrate/Nitrite	µg/l	50.0
Total Cyanide	µg/l	20.0
Total Dissolved Solids	µg/l	10,000.0
Total Phosphorus	µg/l	10.0
Total Sulfide	µg/l	1,000.0
Total Suspended Solids	µg/l	4,000.0
Metals		
Aluminum	µg/l	200.0
Antimony	µg/l	20.0
Arsenic	µg/l	2.0
Barium	µg/l	200.0
Beryllium	µg/l	5.0
Boron	µg/l	100.0
Cadmium	µg/l	5.0
Calcium	µg/l	5,000.0
Chromium	µg/l	10.0
Cobalt	µg/l	50.0
Copper	µg/l	25.0
Iron	µg/l	100.0
Lead	µg/l	50.0
Magnesium	µg/l	5,000.0
Manganese	µg/l	15.0
Mercury	ng/l	0.5
Molybdenum	µg/l	10.0
Nickel	µg/l	40.0
Phosphorus	µg/l	1,000.0
Potassium	µg/l	1,000.0
Selenium	µg/l	5.0
Sodium	µg/l	5,000.0
Sulfur	µg/l	1,000.0
Thallium	µg/l	10.0
Titanium	µg/l	5.0
Vanadium	µg/l	50.0
Zinc	µg/l	20.0

Source: Development Document for Effluent Limitations Guidelines and Standards for the Centralized Waste Treatment Industry, [EPA, 2000]; EPA Method 1631E; [CSC, 2013]

For some pollutants, EPA did not have a baseline value identified from the 2000 CWT ELGs. For these pollutants, EPA used the sample-specific method detection limit (MDL) for the analysis. For some wastestreams (e.g., ash transport water), there were pollutants that did not have a baseline value nor a sample-specific MDL; therefore, these pollutants were not included in the analysis and were not identified as a POC for the specific wastestream. Finally, for some wastestreams, EPA identified pollutants as POCs because they were identified as POCs for the wastestream during previous rulemakings. Using the criteria described above, EPA developed lists of POCs for each fuel combustion wastewater: FGD wastewater, fly ash transport water, bottom ash transport water, landfill combustion residual leachate, impoundment combustion residual leachate, FGMC wastewater, gasification wastewater, and nonchemical metal cleaning wastes. The following sections identify the POCs for each wastestream. The POCs identified for each wastestream are used only as the basis for the selection of regulated pollutants, described in Section 11.

6.7.1 FGD Wastewater Pollutants of Concern

EPA reviewed untreated wastewater data from seven steam electric power plants operating FGD wastewater treatment systems (total of seven sampling points and 28 samples) to identify POCs for FGD wastewater; see Table 6-17. EPA identified 35 POCs using the criteria presented in Section 6.7.

Table 6-17. Pollutants of Concern – FGD Wastewater

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Oil and Grease[a]
	Total Suspended Solids
Priority Pollutants	Antimony
	Arsenic
	Beryllium
	Cadmium
	Chromium
	Copper
	Cyanide
	Lead
	Mercury
	Nickel
	Selenium
	Thallium
	Zinc
Nonconventional Pollutants	Aluminum
	Ammonia
	Barium
	Boron
	Calcium

Table 6-17. Pollutants of Concern – FGD Wastewater

Pollutant Group	Pollutant of Concern
Nonconventional Pollutants	Chemical Oxygen Demand
	Chloride
	Cobalt
	Iron
	Magnesium
	Manganese
	Molybdenum
	Nitrate/Nitrite
	Nitrogen Total, Kjeldahl
	Phosphorus
	Sodium
	Sulfate
	Titanium
	Total Dissolved Solids
	Vanadium

Source: EPA Sampling Data, [ERG, 2012a – 2012g]; [ERG, 2013a].

a – EPA did not analyze its field sampling data for oil and grease. Rather, since the existing steam electric ELGs currently contain BPT limitations applicable to FGD wastewater for oil and grease, EPA already has data from the existing rulemaking demonstrating oil and grease is also a pollutant of concern in FGD wastewater.

6.7.2 Ash Transport Water Pollutants of Concern

EPA sampled untreated fly ash sluice at one plant during the steam electric detailed study. EPA reviewed the untreated fly ash transport water data from this plant (one sampling point and one sample) to identify POCs for fly ash transport water. Table 6-18 lists the POCs identified for fly ash transport water. EPA identified 24 POCs using the criteria presented in Section 6.7. EPA also identified selenium as a POC for fly ash transport water based on a study conducted at Belews Lake that linked fish kills to selenium accumulation in the lake associated with discharges from a power plant, as well as other documented instances of harm caused by discharges of selenium in ash transport water [Lemly, 1985]. As discussed above in Section 6.7, the criterion EPA used as a screening tool to identify pollutants of concern is less applicable in cases where the technology basis results in complete removal of all pollutants present, such as would occur under the technology options considered for fly ash transport water, bottom ash transport water, and FGMC wastewater. For these "zero discharge" technologies, confirmation that a pollutant is present in the wastestream at quantifiable levels may be sufficient to identify a pollutant as a pollutant of concern. Based on the information in the record for selenium in ash transport water, EPA identified it as a pollutant of concern.

Table 6-18. Pollutants of Concern – Ash Transport Water

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Oil and Grease[a]
	Total Suspended Solids
Priority Pollutants	Arsenic
	Beryllium
	Chromium
	Copper
	Lead
	Mercury
	Nickel
	Selenium
	Zinc
Nonconventional Pollutants	Aluminum
	Barium
	Boron
	Calcium
	Chloride
	Iron
	Manganese
	Molybdenum
	Nitrate/Nitrite
	Sodium
	Titanium
	Total Dissolved Solids
	Vanadium
	Yttrium

Source: [ERG, 2008]; [ERG, 2013a].

a – EPA did not analyze its field sampling data for oil and grease. Rather, since the existing steam electric ELGs currently contain BPT limitations applicable to fly ash transport water for oil and grease, EPA already has data from the existing rulemaking demonstrating oil and grease is also a pollutant of concern in fly ash transport water.

Constituents present in ash, and therefore ash transport water, are primarily derived from the type of coal/petroleum coke burned; therefore, as discussed in Section 6.2.3, EPA expects that the bottom ash transport water will have the same constituents that are found in the fly ash transport water. For this reason, the POCs for bottom ash transport water are identical to those of fly ash transport water.

6.7.3 Combustion Residual Leachate Pollutants of Concern

As part of the Steam Electric Survey, EPA required a subset of plants to sample their leachate from impoundments and landfills containing combustion residual. EPA reviewed the untreated landfill and impoundment leachate data collected from the survey responses to identify

POCs for landfill leachate and POCs for impoundment leachate. Table 6-19 lists the POCs identified for combustion residual landfill leachate using the criteria presented in Section 6.7.

Table 6-19. Pollutants of Concern – Landfill Leachate

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Oil and Grease[a]
	Total Suspended Solids
Priority Pollutants	Arsenic
	Mercury
	Selenium
Nonconventional Pollutants	Aluminum
	Boron
	Calcium
	Chloride
	Iron
	Magnesium
	Manganese
	Molybdenum
	Sodium
	Sulfate
	Total Dissolved Solids

Source: Steam Electric Survey , [ERG, 2013b]; [ERG, 2013a].

a – The landfill leachate samples were not analyzed for oil and grease (O&G). Rather, since the existing steam electric ELGs currently contain BPT limitations applicable to combustion residual leachate for O&G, EPA already has data from the existing rulemaking demonstrating O&G is also a pollutant of concern in combustion residual leachate.

Table 6-20 lists the POCs identified for combustion residual impoundment leachate using the criteria presented in Section 6.7.

Table 6-20. Pollutants of Concern – Impoundment Leachate

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Oil and Grease[a]
Priority Pollutants	Arsenic
	Mercury
Nonconventional Pollutants	Boron
	Calcium
	Chloride
	Iron
	Magnesium
	Manganese
	Molybdenum
	Sodium
	Sulfate
	Total Dissolved Solids

Source: Steam Electric Survey, [ERG, 2013b]; [ERG, 2013a].

a – The impoundment leachate samples were not analyzed for O&G. Rather, since the existing steam electric ELGs currently contain BPT limitations applicable to combustion residual leachate for O&G, EPA already has data from the existing rulemaking demonstrating O&G is also a pollutant of concern in combustion residual leachate.

6.7.4 Gasification Wastewater Pollutants of Concern

EPA sampled wastewater streams at two plants operating IGCC generating units as part of the CWA 308 sampling program discussed in Section 3.4. EPA reviewed the untreated wastewater data from these two stream electric power plants (5 sampling points and 20 samples) to identify POCs for IGCC wastewater.

EPA identified 20 POCs for gasification wastewater. Table 6-21 lists the POCs EPA identified using the criteria discussed in Section 6.7.

Table 6-21. Pollutants of Concern – Gasification Wastewater

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Biochemical Oxygen Demand
Priority Pollutants	Antimony
	Arsenic
	Cyanide
	Mercury
	Nickel
	Selenium
	Thallium
Nonconventional Pollutants	Aluminum
	Ammonia

Table 6-21. Pollutants of Concern – Gasification Wastewater

Pollutant Group	Pollutant of Concern
Nonconventional Pollutants	Boron
	Chemical Oxygen Demand
	Chloride
	Iron
	Manganese
	Nitrate/Nitrite
	Nitrogen Total, Kjeldahl
	Sodium
	Sulfate
	Total Dissolved Solids

Source: CWA 308 Monitoring Data, [ERG, 2012h]; [ERG, 2013a].

6.7.5 Flue Gas Mercury Control Wastewater Pollutants of Concern

As described in Section 6.4, for ACI systems, the activated carbon can either be injected upstream or downstream of the primary particulate removal system. When the activated carbon is injected upstream of the primary particulate removal system, the FGMC waste is captured with the fly ash removed by the system. When the activated carbon is injected downstream of the primary particulate removal system, the FGMC waste must be collected in a separate particulate removal system, typically a fabric filter baghouse, and residual fly ash that passes through the primary particulate removal system may also be captured in the system.

The FGMC waste/fly ash from either of these configurations can be handled using either a wet sluicing system or dry handling system. Based on responses to the Steam Electric Survey, EPA determined that more plants are operating ACI systems injecting the carbon upstream of the primary particulate removal system compared to downstream injection. Additionally, EPA determined that there are more plants operating wet sluicing systems for upstream carbon injection compared to downstream injection. Based on these data, EPA determined that the majority of plants generating FGMC wastewater are collecting the FGMC waste with the bulk of the fly ash removed from the flue gas. Therefore, because EPA does not have any sampling data specific to FGMC wastewater, EPA assumed that the pollutants of concern associated with FGMC wastewater will be the same as those for fly ash transport water. Based on this assumption, EPA identified 25 POCs associated with FGMC wastewater. Table 6-22 lists the POCs identified for FGMC wastewater, which is the same as the list for fly ash transport water, presented in Table 6-18.

Table 6-22. Pollutants of Concern – Flue Gas Mercury Control Wastewater

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Oil and Grease
	Total Suspended Solids
Priority Pollutants	Arsenic
	Beryllium
	Chromium
	Copper
	Lead
	Mercury
	Nickel
	Selenium
	Zinc
Nonconventional Pollutants	Aluminum
	Boron
	Barium
	Calcium
	Chloride
	Iron
	Manganese
	Molybdenum
	Nitrate/Nitrite
	Sodium
	Titanium
	Total Dissolved Solids
	Vanadium
	Yttrium

Source: [ERG, 2008]; [ERG, 2013a].

6.7.6 Nonchemical Metal Cleaning Wastes Pollutants of Concern

As part of the 1974 rulemaking, EPA collected characterization data associated with chemical and nonchemical metal cleaning wastes. Based on the data collected during that rulemaking, EPA determined that TSS, oil and grease (O&G), copper, and iron were pollutants of concern for metal cleaning waste warranting regulation. As such, EPA set BPT limitations for these four pollutants in discharges of metal cleaning wastes, including both nonchemical and chemical cleaning wastes, as shown in Table 1-1. For additional information regarding the pollutants that may be present in nonchemical metal cleaning wastes, see the 1974 *Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category* [U.S. EPA, 1974].

Based on this assessment, EPA determined that TSS, O&G, copper, and iron are POCs for nonchemical metal cleaning wastes. Table 6-23 presents the four POCs for nonchemical metal cleaning wastes.

Table 6-23. Pollutants of Concern – Nonchemical Metal Cleaning Wastes

Pollutant Group	Pollutant of Concern
Conventional Pollutants	Oil & Grease
	Total Suspended Solids
Priority Pollutants	Copper
Nonconventional Pollutants	Iron

Source: [U.S. EPA, 1974].

6.8 REFERENCES

1. Babcock & Wilcox Company. 2005. *Steam: Its Generation and Use*. 41st edition. Edited by J.B. Kitto and S.C. Stultz. Barberton, Ohio. DCN SE02919.
2. Computer Sciences Corporation (CSC). 2013. Results of the ICP/MS Collision Cell Method Detection Limit Studies in the Synthetic Flue Gas Desulfurization Matrix. (16 January). DCN SE03872.
3. Duke Energy. 2011a Industry Provided Sampling Data from Duke Energy's Belews Creek Steam Station. (17 August). DCN SE01808.
4. Duke Energy. 2011b Industry Provided Sampling Data from Duke Energy's Allen Steam Station. (17 August). DCN SE01809.
5. Eastern Research Group (ERG). 2008. Final Sampling Episode Report, Buckeye Power Company's Cardinal Power Plant. (August 26). DCN SE02107.
6. Eastern Research Group (ERG). 2012a. Final Sampling Episode Report, Duke Energy Carolinas' Belews Creek Steam Station. (13 April). DCN SE01305.
7. Eastern Research Group (ERG). 2012b. Final Sampling Episode Report, We Energies' Pleasant Prairie Power Plant. (13 April). DCN SE01306.
8. Eastern Research Group (ERG). 2012c. Final Sampling Episode Report, Duke Energy Miami Fort Station. (13 April). DCN SE01304.
9. Eastern Research Group (ERG). 2012d. Final Sampling Episode Report, Duke Energy Carolinas' Allen Steam Station. (13 April). DCN SE01307.
10. Eastern Research Group (ERG). 2012e. Final Sampling Episode Report, Mirant Mid-Atlantic, LLC's Dickerson Generating Station. (13 April). DCN SE01308.
11. Eastern Research Group (ERG). 2012f. Final Sampling Episode Report, Allegheny Energy's Hatfield's Ferry Power Station. (13 April). DCN SE01310.
12. Eastern Research Group (ERG). 2012g. Final Sampling Episode Report, RRI Energy's Keystone Generating Station. (13 April). DCN SE01309.

13. Eastern Research Group (ERG). 2012h. Final Power Plant Monitoring Data Collected Under Clean Water Act Section 308 Authority ("CWA 308 Monitoring Data"). (30 May). DCN SE01326.

14. Eastern Research Group (ERG). 2013a. Memorandum to the Steam Electric Rulemaking Record: Pollutants of Concern Memorandum. (19 April). DCN SE02124.

15. Eastern Research Group (ERG). 2013b. Steam Electric Technical Questionnaire Database ("Steam Electric Survey"). (19 April). DCN SE01958.

16. Electric Power Research Institute (EPRI). 1998a. PISCES Water Characterization Field Study, Sites D Report. TR-108892-V1. Palo Alto, CA. (August). DCN SE01820.

17. Electric Power Research Institute (EPRI). 1998b. PISCES Water Characterization Field Study, Sites D Appendix. TR-108892-V2. Palo Alto, CA. (August). DCN SE01820A1.

18. Electric Power Research Institute (EPRI). 2006. Flue Gas Desulfurization (FGD) Wastewater Characterization: Screening Study. 1010162. Palo Alto, CA. (March). DCN SE01816.

19. Lemly, D.A., 1985. Toxicology of Selenium in a Freshwater Reservoir: Implications for Environmental Hazard Evaluation and Safety. Ecotoxicology and Environmental Safety, 10: 314-338. DCN SE01363.

20. NCDENR. 2011. North Carolina Department of Environment and Natural Resources (NCDENR). State Provided Sampling Data from North Carolina's Progress Energy Roxboro Plant. (26 June). DCN SE01812.

21. U.S. EPA. 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C. (October). DCN SE02917.

22. U.S. EPA. 1982. *Development Document for Effluent Limitations Guidelines and Standards and Pretreatment Standards for the Steam Electric Point Source Category*. EPA-440-1-82-029. Washington, DC. (November). DCN SE02933.

23. U.S. EPA, 2000. Development Document for Effluent Limitations Guidelines and Standards for the Centralized Waste Treatment Industry. (August). DCN SE02920.

24. U.S. EPA Office of Research and Development. 2006. Characterization of Mercury-Enriched Coal Combustion Residues from Electric Generating Utilities using Enhanced Sorbents for Mercury Control. (February). DCN SE01339.

25. U.S. EPA. 2008. Characterization of Coal Combustion Residues from Electric Utilities Using Wet Scrubbers for Multi-Pollutant Control. EPA-600-R-08-077. (July). Available online at: http://www.epa.gov/nrmrl/pubs/600r08077/600r08077.pdf. DCN SE02921.

SECTION 7
TREATMENT TECHNOLOGIES AND WASTEWATER MANAGEMENT PRACTICES

This chapter provides an overview of treatment technologies and wastewater management practices at steam electric power plants for flue gas desulfurization (FGD) wastewater, fly ash and bottom ash handling, combustion residual landfill leachate, gasification wastewater, and flue gas mercury control (FGMC) wastewater.

7.1 FGD WASTEWATER TREATMENT TECHNOLOGIES AND MANAGEMENT PRACTICES

During the Steam Electric Power Generating study and rulemaking, EPA identified 145 steam electric power plants that generate FGD wastewater. Of these plants, 117 (81 percent) discharge FGD wastewater after treatment. EPA identified and investigated wastewater treatment systems operated by steam electric power plants discharging FGD wastewater, as well as operating/management practices that plants use to reduce the pollutants associated with discharge of FGD wastewater. A list of the treatment technologies and management practices, including a brief description of each, are included below. This section provides a detailed description of each of the treatment technologies and management practices listed below.

- *Surface Impoundments*: Surface impoundments (e.g., settling ponds) remove particulates from wastewater by means of gravity. Impoundments are typically sized to reduce total suspended solids (TSS) and allow for a certain residence time within the impoundment.
- Chemical Precipitation: In chemical precipitation systems, the wastewater is treated in tank-based systems. Chemicals are added to enhance the removal of suspended solids and to remove dissolved solids, particularly metals. The precipitated solids are then removed from solution by coagulation/flocculation followed by clarification and/or filtration.
- Biological Treatment: Power plants can also treat FGD wastewater using biological treatment systems. EPA identified three types of biological treatment systems currently used to treat FGD wastewater, including aerobic/anaerobic sequencing batch reactors (target removals of organics and nutrients), fixed-film bioreactors (target removals of nitrogen compounds and selenium), and suspended growth systems (target removals of selenium and other metals).
- Vapor-Compression Evaporation System: This type of system uses a falling-film evaporator (or brine concentrator) to produce a concentrated wastewater stream and a distillate stream to reduce wastewater by 80 to 90 percent (with a pretreatment step) and similarly reduce the discharge of pollutants. The concentrated wastewater may be further processed in a crystallizer or spray dryer.
- Constructed Wetlands: Constructed wetlands are engineered systems that use natural biological processes involving wetland vegetation, soils, and microbial activity to reduce the concentrations of metals, nutrients, and TSS in wastewater.
- Design/Operating Practices Achieving Zero Discharge: EPA identified four design/operating practices available enabling plants to eliminate the discharge of

FGD wastewater: 1) several variations of complete recycle, 2) evaporation impoundments, 3) conditioning dry fly ash, and 4) underground injection.

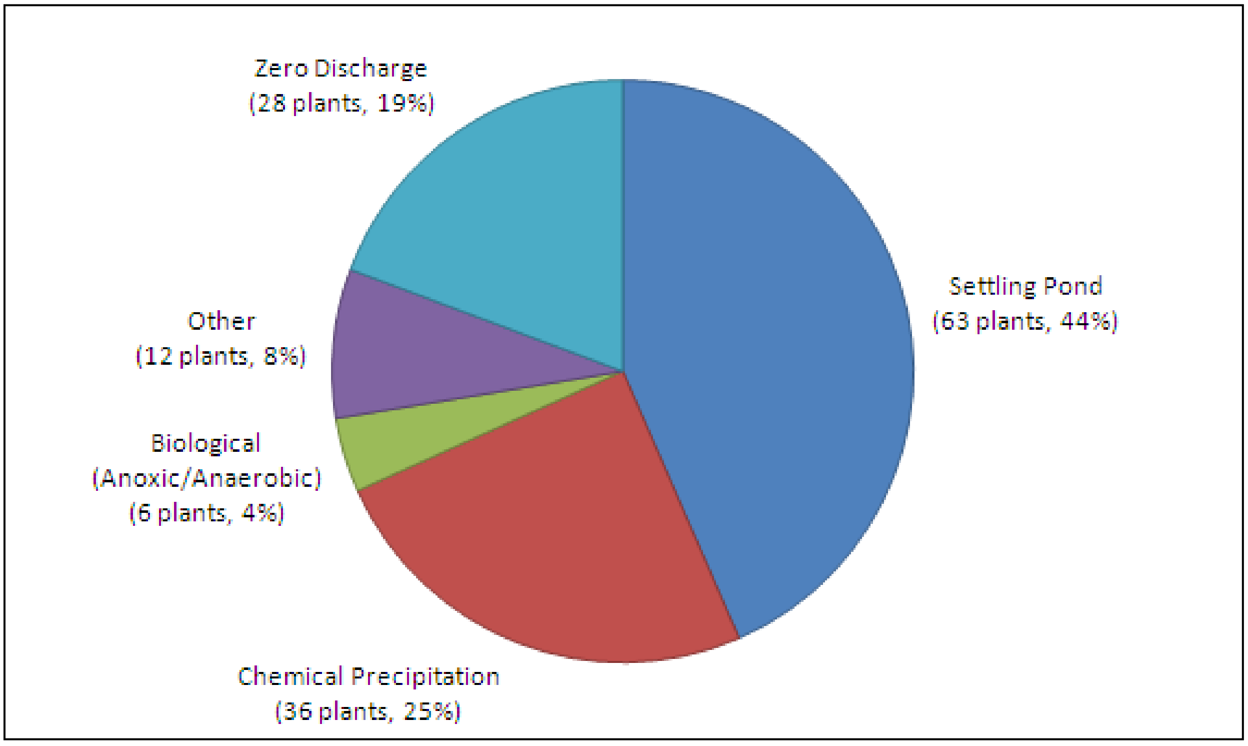
- Other Technologies Under Investigation: EPA identified several other technologies that have been evaluated for treatment of FGD wastewater, including iron cementation, reverse osmosis, absorption media, ion exchange, and electro-coagulation. Other technologies under laboratory-scale study include polymeric chelates, taconite tailings, and nano-scale iron reagents.

Most plants currently discharging FGD wastewater use surface impoundments for treatment; however, the use of more advanced wastewater treatment systems is increasing due to more stringent requirements imposed by some states and regions on a site-specific basis. Figure 7-1 shows the distribution of FGD wastewater management/treatment technologies reported in the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) for the 145 plants that reported using a wet FGD scrubber system in 2009 or planning to operate one by January 1, 2014. Because the majority of the FGD wastewater management/ treatment technologies are surface impoundments, chemical precipitation systems, biological treatment, or zero discharge, EPA grouped the vapor-compression evaporation and constructed wetlands with the "Other" technologies for Figure 7-1. For the purpose of Figure 7-1, to identify the different treatment systems reported in the Steam Electric Survey, EPA grouped the systems into the following categories:

- Surface Impoundments: This grouping includes systems comprising of one or more impoundments where the impoundment is the only treatment unit. This grouping also includes impoundments with chemical addition to control pH levels prior to discharge. This grouping does not include systems containing impoundments as treatment units in a more advanced treatment system (i.e., chemical precipitation, biological treatment). This grouping does not include systems that achieve zero discharge of FGD wastewater.
- Chemical Precipitation: This grouping includes systems using hydroxide and/or sulfide precipitation as the treatment mechanism. This grouping also includes systems using surface impoundments in combination with chemical precipitation systems and systems with chemical precipitation in combination with aerobic biological treatment for BOD_5 removal or biological treatment designed for nutrient removal (i.e., not designed for heavy metals removal). This grouping does not include systems with chemical precipitation and anoxic/anaerobic biological treatment systems. This grouping does not include systems that achieve zero discharge of FGD wastewater.
- Biological Treatment: This grouping includes systems using anoxic/anaerobic or suspended growth biological treatment systems designed for the removal of heavy metals. This grouping includes systems that also include surface impoundments and/or chemical precipitation treatment units in combination with the biological system. This grouping does not include systems that achieve zero discharge of FGD wastewater.
- Other: This grouping includes systems using constructed wetlands or vapor-compression evaporation treatment units. This grouping includes systems that also include surface impoundments in combination with the constructed wetland/vapor-

compression evaporation system. This grouping does not include systems that achieve zero discharge of FGD wastewater.

- Zero Discharge: This grouping includes all FGD wastewater treatment systems that achieve zero discharge, regardless of the treatment units (e.g., surface impoundments, chemical precipitation) used to treat the wastewater prior to reuse. Chemical precipitation systems using aerobic biological treatment to remove BOD were classified as chemical precipitation; and



Source: Steam Electric Survey [ERG, 2013g]

Figure 7-1. Distribution of FGD Wastewater Treatment/Management Systems Among 145 Plants Currently Operating Wet FGD Systems or Planned Wet FGD Systems Operating by 2014

7.1.1 Surface Impoundments

Surface impoundments are designed to remove particulates from wastewater using gravity sedimentation. For this to occur, the wastewater must stay in the impoundment long enough for particles to fall out of suspension before being discharged from the impoundment. The size and configuration of surface impoundments varies by plant; some surface impoundments operate as a system of several impoundments, operated in series or in parallel, while others consist of one large impoundment. Plants typically size the impoundments to provide enough residence time to reduce the total suspended solids (TSS) levels in the wastewater to a target concentration and to allow for a certain lifespan of the impoundment based on the expected rate of solids buildup within the impoundment. Coal-fired power plants do not typically add treatment chemicals to surface impoundments, other than to adjust the pH of the wastewater before it exits the impoundment to bring it into compliance with National Pollutant Discharge Elimination System (NPDES) permit limits.

Surface impoundments can reduce the amount of TSS in the wastewater discharge provided sufficient residence time. In addition to TSS, surface impoundments can also reduce some specific pollutants in the particulate form to varying degrees in the wastewater discharge. However, surface impoundments are not designed to reduce the amount of dissolved metals in the wastewater. The FGD wastewater entering a treatment system contains significant concentrations of several pollutants in the dissolved phase, including manganese, selenium, and boron. These dissolved metals are not largely removed by the FGD wastewater surface impoundments [ERG, 2008]. Additionally, the Electric Power Research Institute (EPRI) has reported that adding FGD wastewater to ash impoundments reduces the settling efficiency of the impoundment leading to increased TSS concentrations and therefore, increased concentrations of other pollutants (e.g., metals), due to gypsum particle dissolution occurring in the impoundment [EPRI, 2006]. EPRI has also reported that the FGD wastewater includes high loadings of volatile metals that can affect the solubility of metals in the ash impoundment, thereby potentially increasing the effluent metal concentrations [EPRI, 2006].

EPA compiled data for the 145 plants operating wet FGD systems, or planned wet FGD systems operating by 2014, and the wastewater treatment systems used to treat the FGD wastewaters generated. Based on these data, surface impoundments are the most commonly used systems for managing FGD wastewater (approximately 44 percent). Most of these plants transfer the FGD wastewater directly to a surface impoundment that also treats other wastestreams, specifically fly and/or bottom ash transport water. Approximately 23 percent of plants managing FGD wastewater with surface impoundments transfer the FGD wastewater to a segregated surface impoundment specifically designated to treat FGD wastewater [ERG, 2013g]. These plants either discharge the FGD wastewater effluent directly to surface waters from the segregated FGD surface impoundment (with or without commingling with cooling water or other large volume wastes streams) while others transfer the effluent to another impoundment, potentially containing other combustion residual wastes (i.e., ash), for further settling and dilution.

EPA has also identified plants that transfer the FGD wastewater to a surface impoundment for initial solids removal and then pump the wastewater to a chemical precipitation system or a biological treatment system for further treatment. As previously mentioned, because these surface impoundments are treatment units in a more advanced wastewater treatment system, EPA classifies these plants as “chemical precipitation” or “biological” rather than “surface impoundments,” respectively.

7.1.2 Chemical Precipitation

In a chemical precipitation wastewater treatment system, plants add chemicals to the wastewater to alter the physical state of dissolved and suspended solids to help settle and remove the solids. The specific chemical(s) used depends upon the type of pollutant requiring removal. EPA identified 40 steam electric power plants using chemical precipitation systems to treat FGD wastewater. Power plants commonly use the following three types of systems to precipitate metals out of FGD wastewater:

- Hydroxide precipitation (40 plants);
- Iron coprecipitation (38 plants); and
- Sulfide precipitation (33 plants).

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.

Thirty-eight power plants use iron coprecipitation as a way to increase the removal of certain metals in a hydroxide precipitation system. Plants can add ferric (or ferrous) chloride to the precipitation system to coprecipitate additional metals and organic matter.[35] The ferric chloride also acts as a coagulant, forming a dense floc that enhances settling of the metals precipitate in downstream clarification stages.

Sulfide precipitation systems use sulfide chemicals (e.g., trimercapto-s-triazine (TMT), Nalmet® 1689, sodium sulfide) to precipitate and remove heavy metals, similar to the set of metals removed in hydroxide precipitation. Plants operating sulfide precipitation systems can use TMT, Nalmet® 1689, MetClear™, sodium sulfide, or other sulfide chemicals in the system. The plants may test several different sulfide chemicals to determine the one most appropriate for their treatment system. Sulfide precipitation can also provide more optimal removal of metals with lower solubilities, such as mercury, than hydroxide precipitation or hydroxide precipitation with iron co-precipitation. The EPA sampling data suggest that adding organosulfide to the FGD wastewater can reduce dissolved mercury concentrations to the tens of parts per trillion [ERG, 2012b]. Sulfide precipitation is more effective than hydroxide precipitation in removing metals with low solubilities because metal sulfides have lower solubilities than metal hydroxides. Because sulfide precipitation is more expensive than hydroxide precipitation, plants usually use hydroxide precipitation first to remove most of the metals, and then sulfide precipitation to remove the remaining low solubility metals. This configuration overall requires less sulfide, thereby reducing the expense for the bulk metals removal.

FGD wastewater chemical precipitation systems may include various stages of lime, sulfide, and ferric chloride addition, as well as clarification stages. Some plants add all three chemicals (i.e., lime, ferric chloride, and organosulfide) to a single reaction tank, whereas other plants add the chemicals to separate tanks. The plants operating separate tanks may be targeting different pH set points within the system for optimal precipitation of certain metals. For example, We Energies' Pleasant Prairie Power Plant (Pleasant Prairie) adds hydrated lime to its FGD wastewater in the first reaction tank of the treatment system, raising the pH from 5.5 to 8.5 S.U. to precipitate soluble metals as insoluble hydroxides and oxyhydroxides. After primary

[35] The remainder of this section discusses the use of ferric chloride, as ferrous chloride is not commonly used in the steam electric industry. However, ferrous chloride could also be used in the place of ferric chloride.

clarification, the wastewater flows to a second reaction tank and the plant adds organosulfide and hydrochloric acid, which drops the pH to around 7 S.U. Pleasant Prairie determined that adding the organosulfide at a neutral pH removed more mercury compared to operating at a more basic pH level [ERG, 2013c].

During its site visit program, EPA determined that the majority of steam electric power plant permits include only TSS, pH, and oil and grease (O&G) limitations for FGD wastewater based on the current Steam Electric ELGs BPT limits for low volume wastewater. For this reason, 63 plants (44%) operate surface impoundments, as discussed previously, to remove TSS. However, some steam electric power plant permits include limitations for specific metals due to state or regional regulations or local limitations. Most effluent limits in NPDES permits for FGD wastewater (other than TSS and O&G) are water-quality-based effluent limitations (WQBELs) to meet applicable water quality standards. In these cases, a number of plants have opted to install chemical precipitation systems designed and operated to target the specific metal or metals included in the permit. For example, if the plant has a mercury effluent limitation, they are more likely to operate sulfide precipitation, rather than just hydroxide precipitation or a surface impoundment if they had only a limitation for TSS.

One example of a treatment system operating to meet only the BPT-based limitations for TSS, pH, and O&G was AEP's Mountaineer plant, which operates a chemical precipitation system to treat its FGD wastewater. In 2008, one year after the start-up of the FGD scrubbers and the FGD wastewater treatment system, the plant went through a permit renewal process and the state proposed to add a limit for mercury. Based on the proposed mercury limitations in the new permit, AEP conducted a pilot study evaluating three different technologies that could be installed as additional treatment downstream of the currently operating chemical precipitation system. Mountaineer conducted the pilot study from July through December 2008. During the first three months of the study, the mercury concentrations of the chemical precipitation system effluent feeding the pilot tests averaged 1,300 parts per trillion (ppt). None of the three technologies achieved the target effluent concentrations for the pilot testing. Therefore, AEP took steps to optimize the solids removal in the chemical precipitation system, including adding additional polymers and organosulfide. Using these optimization steps, AEP noted that "[t]he combination of supplemental coagulation and organosulfide addition consistently yielded approximately 80 percent of additional mercury reduction…" within the chemical precipitation system [AEP, 2010].

In some cases, plants may experience a spike in concentrations for certain metals in their untreated FGD wastewater, likely based on changes in fuels or operating conditions within the FGD scrubber. EPA's data demonstrate that well operated systems maintain their chemical precipitation effluent concentrations because they actively monitor their untreated wastewater for target concentrations of certain metals allowing them to adjust the operation of the chemical precipitation system, as necessary. Plants that actively monitor their untreated FGD wastewater would be able to identify these excursions and adjust the chemical addition rates to treat the wastewater to the required permit limitation. Some plants actively monitor the influent to the treatment system and adjust chemical addition by including an equalization tank with a 24-hour holding time as the first step in the treatment system. Alternatively, plants could monitor the effluent prior to discharge to make sure that they are in compliance before discharge. For example, Pleasant Prairie monitors the effluent from the system daily by collecting and analyzing samples using an in-house Method DMA 80 mercury analyzer. The analyzer can generate results in approximately six minutes [Michel, 2012]. The plant uses the mercury analyzer to alert operators when mercury concentrations are at levels close to the plant's mercury permit limit; therefore, the operators can adjust the system (e.g., chemical feed rates) to achieve additional mercury removal. When the concentrations are close to the permit limits, the plant begins discharging in the wastewater in batches. The plant transfers the wastewater to the effluent storage tank and when the tank is full, the plant collects a sample of the wastewater to confirm it is below the permit limit. Once the plant confirms the concentration is lower than the limit, the plant discharges the wastewater from the effluent tank [ERG, 2013c].

Figure 7-2 presents a process flow diagram for a chemical precipitation system using hydroxide precipitation, sulfide precipitation, and iron coprecipitation to treat FGD wastewater. This system is designed to remove heavy metals and organic matter. A chemical precipitation system with no sulfide precipitation stage would be similar, but without the sulfide addition reaction tank.

For the system illustrated by Figure 7-2, the plant transfers the FGD wastewater from the plant's solid separation/dewatering process to an equalization tank. This tank equalizes the intermittent flows, allowing the plant to pump a constant flow of wastewater through the treatment system. The equalization tank also receives wastewater from a filtrate sump, which includes water from the gravity filter backwash and filter press filtrate.

The FGD wastewater is transferred in a continuous flow from the equalization tank to reaction tank 1, where the plant adds hydrated lime to raise the pH of the wastewater from between 5.5 – 6.0 S.U. to between 8.0 – 10.5 S.U. to precipitate the soluble metals as insoluble hydroxides and oxyhydroxides. The reaction tank also desaturates the remaining gypsum in the wastewater, which prevents gypsum scale formation in the downstream wastewater treatment equipment.

From reaction tank 1, the wastewater flows to reaction tank 2, where the plant adds organosulfide or inorganic sulfide. Plants can also reconfigure the treatment system by adding the organosulfide upstream of the hydroxide precipitation step or adding a clarification step between the two chemical addition steps.[36]

From reaction tank 2, the wastewater flows to reaction tank 3, where the plant adds ferric chloride to the wastewater for coagulation and coprecipitation. The effluent from reaction tank 3 flows to the flash mix tank, where the plant adds polymer to the wastewater prior to transferring it to the clarifier. Alternatively, the plant can add polymer directly to the wastestream as it enters the clarifier or reaction tank 3. The polymer acts to flocculate fine suspended particles in the wastewater.

[36] Some plants may have a clarification step between reaction tank 1 and reaction tank 2 to remove the hydroxide precipitates from the wastewater prior to adding organosulfide. In addition, plants may adjust the pH prior to sulfide addition to target the removal of different metals.

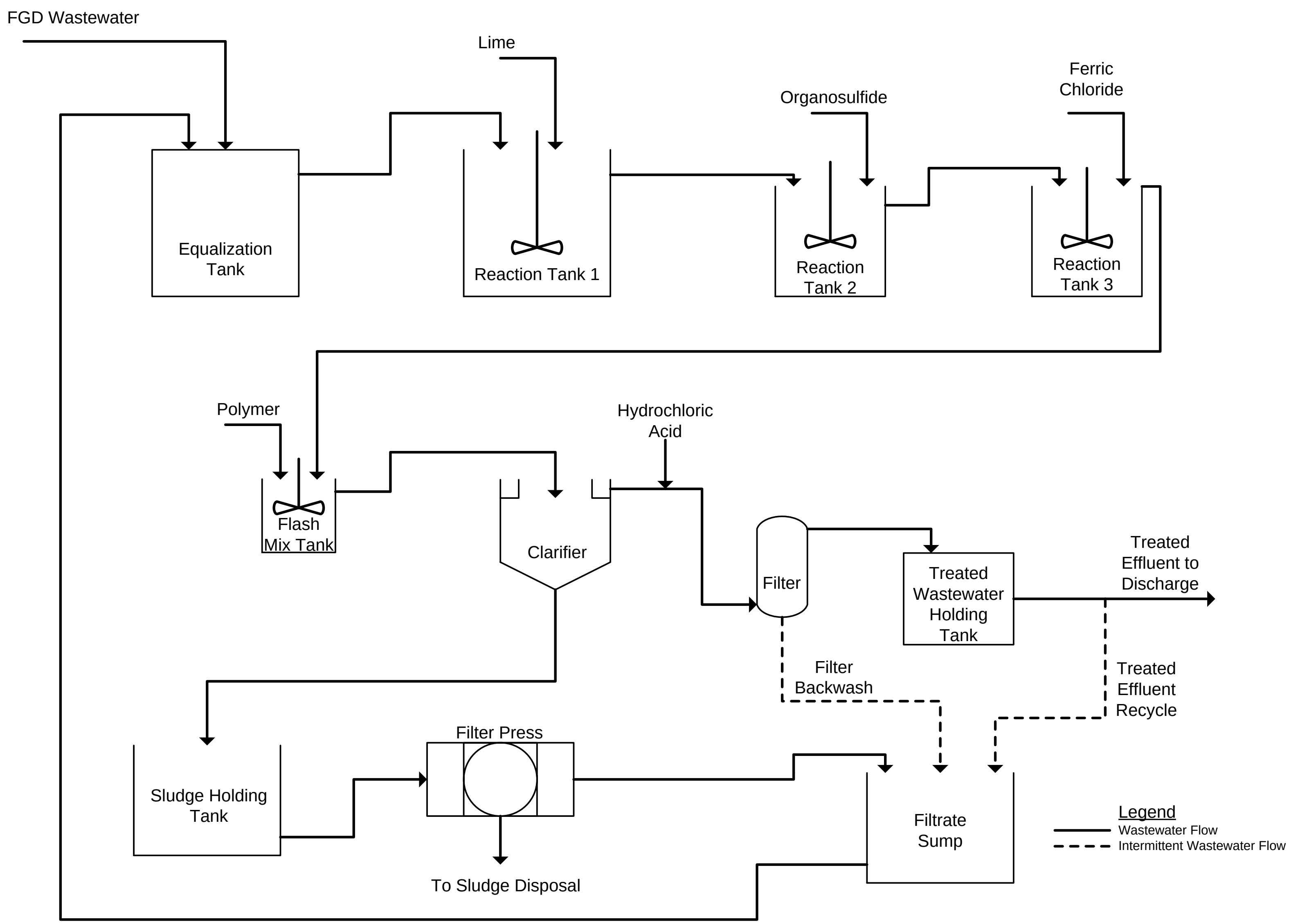


Figure 7-2. Process Flow Diagram for a Hydroxide and Sulfide Chemical Precipitation System

The clarifier settles the solids that were initially present in the FGD wastewater as well as the additional solids (precipitate) formed during the chemical precipitation steps. The system may also include a sand filter to further reduce solids, as well as metals attached to the solids. The system transfers the backwash from the sand filters to a filtrate sump and recycles it back to the equalization tank at the beginning of the treatment system.

The plant collects the treated FGD wastewater in a holding tank and either discharges it directly to surface waters or, in most cases, commingles it with other wastestreams prior to discharge.

The plant transfers the solids that settle in the clarifier (clarifier sludge) to the sludge holding tanks, after which the sludge is dewatered using a filter press. The plant then disposes of the dewatered sludge, or filter cake, in an on-site landfill, and transfers the filtrate from the filter press to a sump and recycles it back to the equalization tank at the beginning of the treatment system.

7.1.3 Biological Treatment

Biological wastewater treatment systems use microorganisms to consume biodegradable soluble organic contaminants and bind much of the less soluble fractions into floc. Pollutants may be reduced aerobically, anaerobically, and/or by using anoxic zones. Based on the information EPA collected during the rulemaking, steam electric power plants use two main types of biological treatment systems to treat FGD wastewater: aerobic systems to reduce biochemical oxygen demand (BOD_5) and anoxic/anaerobic systems to remove metals and nutrients. These systems may consist of fixed film or suspended growth bioreactors, and operate as conventional flow-through or as sequencing batch reactors (SBRs). This section describes the wastewater treatment processes for each of these systems. These biological treatment processes are typically operated downstream of a chemical precipitation system or a solids removal system (e.g., clarifier, surface impoundment).

7.1.3.1 Aerobic Biological Treatment

Some plants operate aerobic biological treatment systems to reduce BOD_5 in their FGD wastewater. In a conventional flow-through design, the system continuously feeds the wastewater to the aerated bioreactor. The plant may add chemicals to the wastewater before it enters the bioreactor to adjust the pH levels and, in certain climates, feed the wastewater through a heat exchanger to maintain a certain temperature to make sure the microorganisms are operating at optimal levels [ERG, 2007]. The microorganisms in the reactor use the dissolved oxygen from the aeration to digest the organic matter in the wastewater, thus reducing the BOD_5. The digestion of the organic matter produces sludge, which the plant may dewater with a vacuum filter to better manage its ultimate disposal. The treated wastewater from the system overflows out of the reactor.

An SBR is a type of activated sludge treatment system that can reduce BOD_5 and, when operated to create anoxic zones under certain conditions, can also reduce nitrogen compounds through nitrification and denitrification. Plants often operate at least two identical reactors sequentially in batch mode. The treatment in each SBR consists of a four-stage process: fill, aeration and reaction, settling, and decant. While one of the SBRs is settling and decanting, the other SBR is filling, aerating, and reacting.

As an aerobic system, the SBR operates as follows. The filling stage of the SBR involves transferring the FGD wastewater into a reactor that contains some activated sludge from the previous reaction batch. During the aeration and reaction stages, the reactor is aerated and the microorganisms reduce the BOD_5 by digesting the organic matter in the wastewater. During the settling phase, the plant stops aeration and the solids in the SBR settle to the bottom. The plant then decants the wastewater off the top of the SBR and transfers it to surface water for discharge or to additional treatment or reuses it in plant processes without further treatment. Additionally, the plant removes and dewaters some of the solids from the bottom of the SBR, but retains some of the solids in the SBR to keep microorganisms in the system.

7.1.3.2 Anoxic/Anaerobic Biological Treatment

Some coal-fired power plants use anoxic/anaerobic biological systems to reduce certain pollutants (e.g., selenium, mercury, nitrates) more effectively than has been possible with surface impoundments, chemical precipitation, or aerobic biological treatment processes. Figure 7-3 presents a process flow diagram for an anoxic/anaerobic biological treatment system. The microorganisms in this system are susceptible to high temperatures in excess of 105 ºF [Pickett, 2005]. Because of this susceptibility, some plants cool the FGD wastewater prior to entering the biological system using heat exchangers or cooling impoundments. Based on data from EPA sampling episodes, these plants generally include those in geographic locations with sustained periods of maximum ambient temperatures greater than 90 ºF [U.S. EPA, 2013].

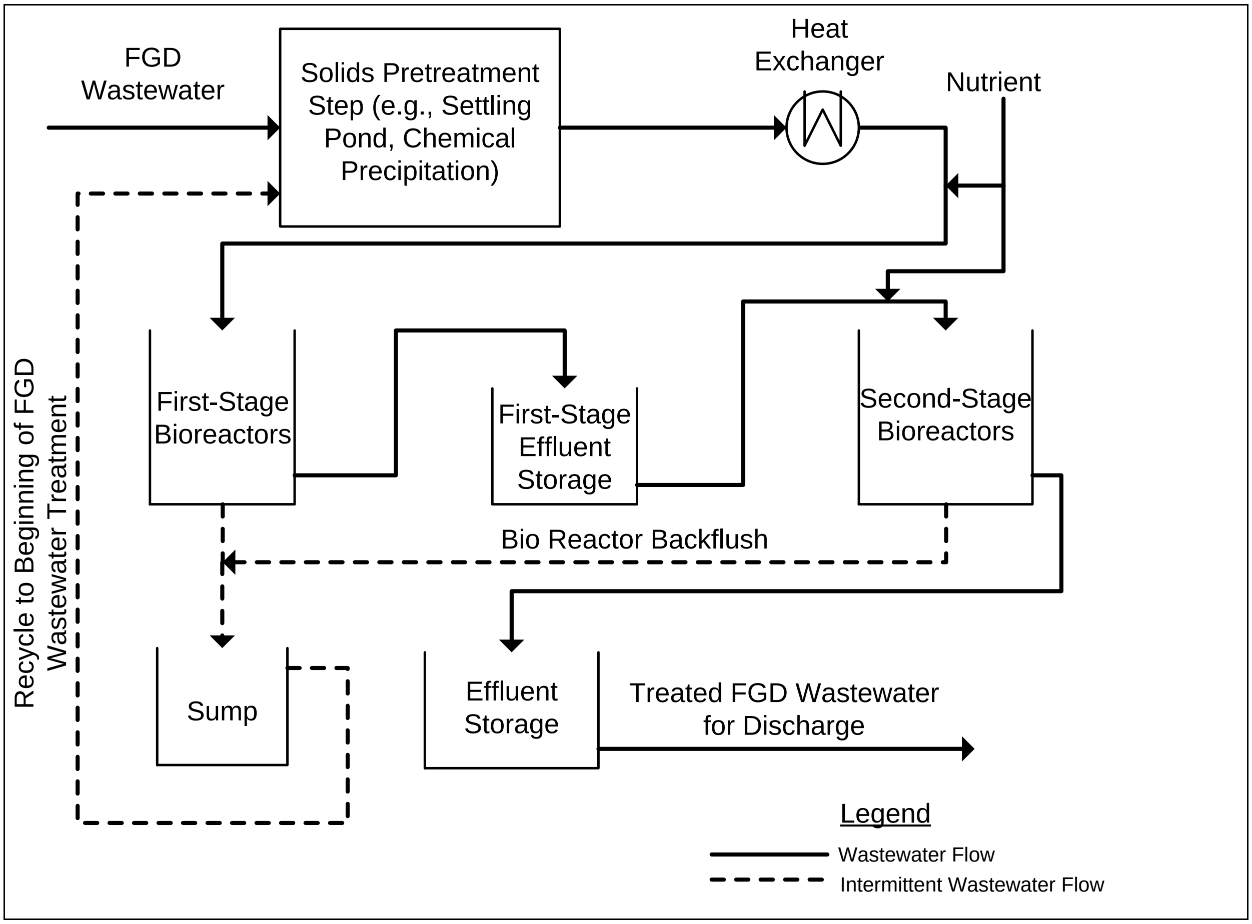


Figure 7-3. Process Flow Diagram for an Anoxic/Anaerobic Biological Treatment System

Plants employing an anoxic/anaerobic biological treatment system operate a fixed-film bioreactor that consists of an activated carbon bed, such as granular activated carbon (GAC) or some other permanent porous substrate, that is inoculated with naturally occurring, beneficial microorganisms that reduce selenium and other metals [Sonstegard, 2010]. The microorganisms grow within the activated carbon bed, creating a fixed-film that retains the microorganisms and precipitated solids within the bioreactor. The system uses microorganisms chosen specifically for use in FGD systems because of their hardiness in the extreme water chemistry as well as selenium respiration and reduction [Sonstegard, 2010]. Power plants also add a molasses-based feed source for the microorganisms to the wastewater before it enters the bioreactor [ERG, 2012a].

The bioreactor is designed for plug flow to ensure the feed water is evenly distributed and has maximum contact with the microorganisms in the fixed-film. The bioreactor contains different zones that have differing oxidation reduction potentials (ORP). Plants operate the bioreactors to achieve a negative ORP within the system, which provides the optimal environment to reduce selenium to its elemental form. The ORP is controlled by the amount of nutrient that is fed to the system [ERG, 2012a]. The top part of the bioreactor, where the plant feeds the wastewater, is aerobic with a positive ORP, which allows nitrification and organic carbon oxidation to occur. As the wastewater moves down through the bioreactor, it enters an anoxic zone (negative ORP) where denitrification as well as chemical reduction of selenium (both selenate and selenite) occur [Pickett, 2006; Sonstegard, 2010]. The system maintains a pH level in the bioreactor between 6.0 and 9.0 S.U. because extreme high or low pH levels could affect the performance of the microbes and potentially allow nondesirable microbes to propagate [ERG, 2012a].

When the microorganisms reduce the selenate and selenite to elemental selenium, it forms nanospheres that adhere to the cell walls of the microorganisms. Because the activated carbon bed retains the microorganisms within the bioreactor, the elemental selenium is essentially fixed to the activated carbon until it is removed from the system. The microorganisms can also reduce other metals, including arsenic, cadmium, and mercury, by forming metal sulfides within the system [Pickett, 2006].

The bioreactor system typically contains multiple bioreactor cells. For example, the Duke Energy Carolinas' Allen Steam Station and Belews Creek Steam Station have two stages of bioreactor cells in series, as shown in Figure 7-3, but both stages of bioreactors contain multiple cells in parallel. Plants usually require multiple bioreactors to provide the necessary residence time to achieve the specified removals.

Periodically, the bioreactor must be backflushed to remove the solids and inorganic materials that have accumulated within it. The flushing process involves flowing water upward through the system, which dislodges the particles fixed within the activated carbon. The water and solids overflow out of the top of the bioreactor and are removed from the system. This flush water contains elevated levels of solids, with selenium adhered to it [Pickett, 2006], and will likely need to be treated prior to discharge. Some plants send the backflush water to the beginning of the chemical precipitation wastewater treatment system so that the system can remove the solids (and adhered selenium) within the clarifier. Other plants transfer the backflush water to a surface impoundment where the solids (and adhered selenium) settle out [ERG, 2010; Jordan, 2008].

As the microorganisms denitrify the wastewater, nitrogen and carbon dioxide gases form, which periodically build up and form pockets within the bioreactor. As a result, water flows through channels, reducing microbial contact and increasing head-loss across the bioreactor, an overall negative effect on the system [Sonstegard, 2010]. To remove these gas pockets, plants occasionally perform a degassing operation by transferring water backwards through the cells, similar to a backflush, but the flush is only long enough for the gas to "burp" out of the system [Allen SER]. The system flush is long enough to lift the biomatrix and release entrained gases, but short enough to avoid flushing any water out of the bioreactor [Sonstegard, 2010].

One plant has pilot tested another type of anoxic/anaerobic biological treatment system that consists of suspended growth flow-through bioreactors instead of fixed-film bioreactors. Both designs share the fundamental processes that lead to nitrification/denitrification and reduction of metals in anoxic and anaerobic environments. Based on the results of the pilot test, in January 2012, the plant commissioned a full-scale suspended growth bioreactor system to treat FGD wastewater [ERG, 2013f].

Plants can also operate SBRs to achieve anoxic/anaerobic conditions. The SBR operation is similar to the aerobic biological treatment system described above; however, the aeration stage would be followed by periods of air on, air off, which creates aerobic zones for nitrification and anoxic zones for denitrification to remove the nitrogen in the wastewater. According to the treatment system vendor, SBR systems will denitrify the wastewaters, but the ORP in the system is not managed at levels conducive to reducing metals. Therefore, these SBR systems will not remove selenium (and other metals) as effectively as the fixed-film or suspended growth bioreactor systems.

7.1.4 Vapor-Compression Evaporation System

Mechanical evaporators in combination with a final drying process can significantly reduce the quantity of wastewater pollutants and volume discharged from certain process operations at various types of industrial plants, including steam electric power plants, oil refineries, and chemical plants. One type of evaporation system uses a falling-film evaporator (also referred to as a brine concentrator) to produce a concentrated wastewater stream (i.e., brine) and a reusable distillate stream. The concentrated wastewater stream may be further processed in a crystallizer or spray dryer, in which the remaining water is evaporated. When used with a crystallizer or spray dryer, this process generates a distillate stream and a solid by-product that can then be disposed of in a landfill.

Steam electric power plants most often use vapor-compression evaporation systems to treat wastestreams such as cooling tower blowdown and demineralizer waste; however, in 2009, one plant in the United States began to operate a vapor-compression evaporation system to treat FGD wastewater [ERG, 2013g]. Two other plants in the United States have installed, or are in the process of installing, this technology [Jacobs Consultancy, 2012; Loewenberg, 2012]. Additionally, four coal-fired power plants in Italy are treating FGD wastewater with vapor-compression evaporation systems [Rao, 2008; Veolia Water Solution, 2007]. Two other plants in Italy also installed vapor-compression evaporation systems but subsequently determined that off-site disposal is more economical.

Before entering the vapor-compression evaporation system, FGD wastewater is usually pretreated to remove calcium and magnesium salts, as shown in Figure 7-4. Calcium and magnesium salts in the FGD wastewater can pose difficulties for the forced-circulation crystallizer. To prevent this, plants can pretreat the FGD wastewater using chemical precipitation and a lime-softening process upstream of the brine concentrator. With water softening, the magnesium and calcium ions precipitate out of the wastewater and are replaced with sodium ions, producing an aqueous solution of sodium chloride that can be more effectively treated with a forced-circulation crystallizer [Shaw, 2008]. See Section 7.1.2 for more specific information on chemical precipitation systems.

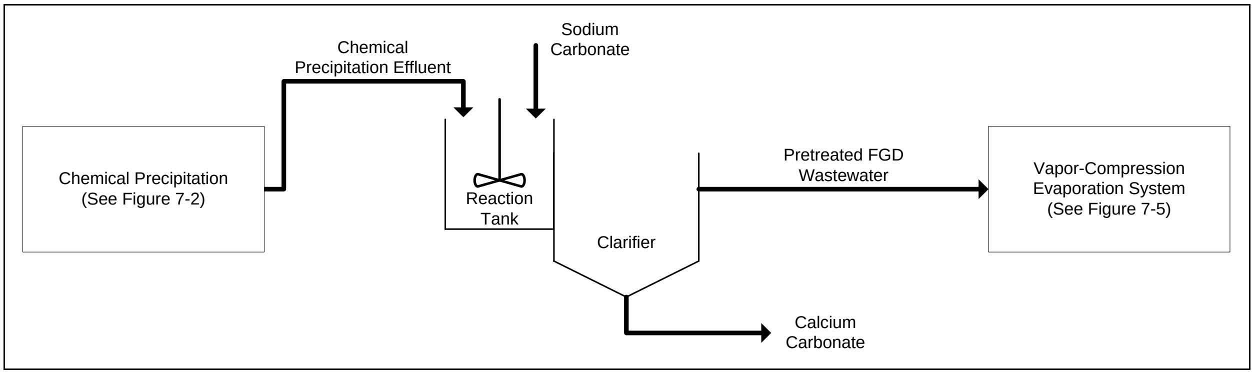


Figure 7-4. Chemical Precipitation and Softening Pretreatment for FGD Wastewater Prior to Vapor-Compression Evaporation

Figure 7-5 presents a process flow diagram for a vapor-compression evaporation system. When a vapor-compression evaporation system is used to treat FGD wastewater, the first step is to adjust the pH of the FGD wastewater to approximately 6.5 S.U. Additionally, some plants add an antiscalant to the wastewater prior to the evaporation system [ERG, 2012d]. Following pH adjustment, the FGD wastewater goes through a heat exchanger to bring the wastestream to its boiling point. From the heat exchanger, the wastewater stream is sent to the deaerator, where the noncondensable materials such as carbon dioxide and oxygen, are vented to the atmosphere [ERG, 2012d].

From the deaerator, the wastestream enters the sump of the brine concentrator. Brine from the sump is pumped to the top of the brine concentrator and enters the heat transfer tubes. While falling down the heat transfer tubes, part of the solution is vaporized and then compressed and comes in contact with the shell side of the brine concentrator (i.e., the outside of the tubes). With the temperature difference between the compressed vapor and the brine solution, the compressed vapor transfers heat to the brine solution, which flashes to a vapor, and the compressed vapor cools and condenses as distilled water [ERG, 2012d].

The condensed vapor (i.e., distillate water) can be recycled back to the FGD process, used in other plant operations (e.g., boiler make-up water), or discharged. If the plant uses the distillate for other plant operations that generate a discharge stream (e.g., used as boiler make-up and ultimately discharged as boiler blowdown), then the FGD process/wastewater treatment system is not truly zero discharge. Therefore, operating a vapor-compression evaporation system does not guarantee that the FGD process/wastewater treatment system achieves zero discharge.

The concentrated brine slurry from the brine concentrator tubes falls into the sump and is recycled with the feed (FGD wastewater) to the top of the brine concentrator. Typically, the plant continuously withdraws a small amount from the sump and transfers it to a final drying process. To prevent scaling within the brine concentrator because of the gypsum in the FGD wastewater, the brine concentrator is seeded with calcium sulfate. The calcium salts preferentially precipitate onto the seed crystals instead of the tube surfaces of the brine concentrator. If the treatment system is preceded by chemical precipitation and softening, the brine concentrator can typically concentrate the FGD scrubber purge five to 10 times, which reduces the inlet FGD scrubber purge water volume by 80 to 90 percent [Shaw, 2008]. However, without pretreatment, the brine

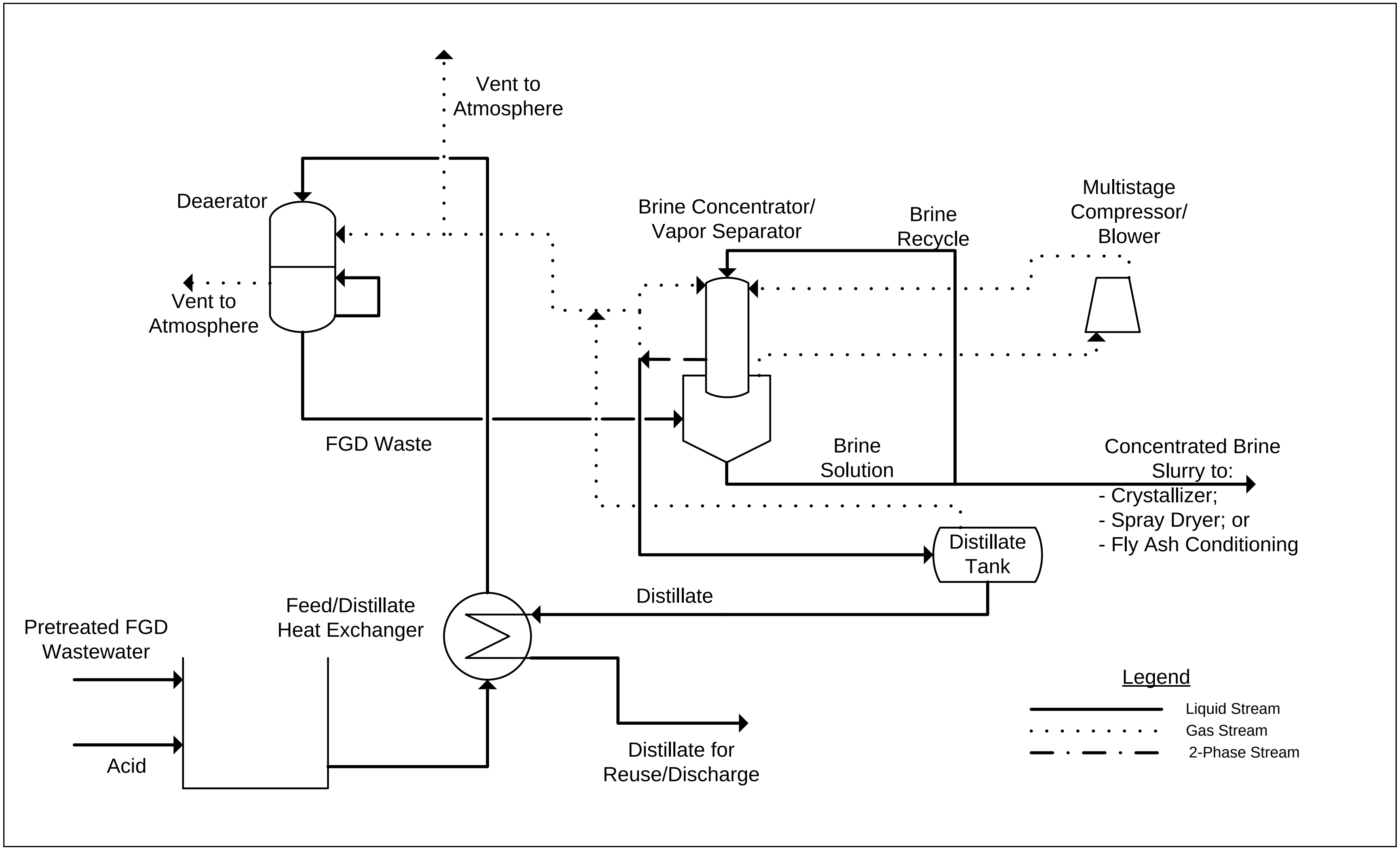


Figure 7-5. Process Flow Diagram for a Vapor-Compression Evaporation System

concentrator is not as effective because of boiling point rise (the increase in energy required to concentrate the wastewater stream because of the additional calcium and magnesium salts or other solids in the wastewater). For example, one plant operates only a clarifier prior to the vapor-compression evaporation system. The brine concentrator reduces the inlet FGD scrubber purge water volume only up to 53 percent [ERG, 2012c].

Plants typically consider three options for eliminating the brine concentrate: (1) evaporating the brine in a brine crystallizer; (2) evaporating the brine in a spray dryer; or (3) using the brine to condition (add moisture to) dry fly ash or other solids and disposing of the mixture in a landfill.

Plants may use brine concentrators to treat a wastestream other than FGD wastewater (e.g., cooling tower blowdown). For these non-FGD systems, the plant typically sends the concentrated brine from the sump to a forced-circulation crystallizer to evaporate the remaining water from the concentrate and generate a solid product for disposal.

Coal-fired power plants can avoid having to operate the chemical precipitation pretreatment process by using a spray dryer to evaporate the residual wastestream from the brine concentrator. Because the material generated from this process is hygroscopic (i.e., readily taking up and retaining moisture), the solid residual from the spray dryer is typically bagged immediately and disposed of in a landfill. Alternatively, the plant can combine the concentrated brine wastestream with dry fly ash or other solids for disposal in a landfill. To do this, the plant must generate enough dry fly ash to mix with the brine; otherwise, there will be brine remaining that the plant must handle.

7.1.5 Constructed Wetlands

A constructed wetland treatment system is an engineered system that uses natural biological processes involving wetland vegetation, soils, and microbial activity to achieve reductions in the concentrations of metals, nutrients, and TSS in wastewater. A constructed wetland typically consists of several cells that contain bacteria and vegetation (e.g., bulrush, cattails, peat moss), which the steam electric plant selects based on the specific pollutants targeted for removal. The vegetation completely fills each cell and produces organic matter (i.e., carbon) used by the bacteria. The bacteria reduce metals in the aqueous phase of the wastewater, such as mercury and selenium, to their elemental state. The metals removed by the bacteria will partition into the sediment, where they either accumulate or are absorbed by the vegetation in the wetland cells [EPRI, 2006; Rogers, 2005].

High temperature, chemical oxygen demand (COD), nitrates, sulfates, boron, and chlorides in the wastewater can adversely affect constructed wetlands' performance. To avoid this, plants typically dilute the FGD wastewater with service water before it enters the wetland to reduce the temperature of the wastewater and concentration of chlorides and other pollutants, which can harm the vegetation in the treatment cells. Plants typically maintain the chlorides in a constructed wetland treatment system below 4,000 mg/L. Because most plants operate their FGD scrubber system to maintain chloride levels within a range of 10,000 – 20,000 ppm, they would need to dilute the FGD wastewater prior to transferring it to a wetland system. EPA identified three plants operating constructed wetlands to treat FGD wastewater. EPA has observed that these steam electric power plants tend to operate the FGD system at lower concentrations of chlorides (e.g., 1,000 to 10,000 ppm). To do this, the plants purge FGD wastewater from the system at a higher flow rate than they otherwise would do if operating the FGD system at a higher chloride concentration level.

7.1.6 Design/Operating Practices Achieving Zero Discharge

During its engineering site visit program, EPA observed that some of the plants operating wet FGD systems designed and/or managed the FGD system to eliminate the discharge of FGD wastewater. EPA identified 28 plants (19%) achieving zero discharge of FGD wastewater. Based on information collected as part of the Steam Electric Survey, EPA identified five design/ operating practices available to prevent the FGD wastewater discharge:

- Variations of complete recycle;
- Evaporation impoundments;
- Underground injection;
- Operation of both wet and dry FGD scrubber systems; and
- Dry fly ash conditioning.

This section discusses each of these practices below.

Complete Recycle

Most plants do not recycle their treated FGD wastewater within the FGD system because of the elevated chloride levels in the treated effluent. Some plants, however, completely recycle the FGD wastewater within the system without using a wastewater purge stream to remove chlorides. Such plants generally do not produce a saleable solid product from the FGD system (e.g., wallboard-grade gypsum). Because the plant is not selling the FGD solid by-product, and therefore, is most likely disposing of it in a landfill, it has no specific chloride specifications for the material. Therefore, the plant can operate the FGD system and solids separation/dewatering process such that the moisture retained with the landfilled solids contains sufficient chlorides that the plant does not need a separate wastewater purge stream. Transferring the FGD solids to the landfill essentially serves as the chloride purge from the system.

From the information provided in the Steam Electric Survey, EPA determined that, of the 145 plants operating wet FGD systems, approximately 16 operate complete recycle systems and do not discharge any FGD wastewaters to surface waters. Of these 16 plants, nine operate natural or inhibited oxidation system, which generate calcium sulfite instead of calcium sulfate, and are therefore more likely to dispose of the solids in a landfill.

Evaporation Impoundments

EPA identified approximately 10 plants located in the southwestern United States that use evaporation impoundments to avoid discharging any FGD wastewaters to surface waters. Because of the warm, dry climate in this region, the plants can transfer the FGD wastewater to one or more impoundments where the water evaporates. The evaporation rate from the impoundments at these plants is greater than or equal to the flow rate of the FGD wastewater and amount of direct precipitation entering the impoundments; therefore, there is no discharge.

Conditioning Dry Fly Ash

Many plants that operate dry fly ash handling systems need to add water to the fly ash to suppress dust or improve handling and/or compaction characteristics. EPA identified six plants that use FGD wastewater to suppress dust around landfills or to moisture condition fly ash prior to landfill disposal [ERG, 2013g]. Another plant, discussed in Section 7.1.4, uses a vapor-compression evaporation system in combination with conditioning dry fly ash to prevent discharging FGD wastewater [ERG, 2013b]. The plant uses the vapor-compression evaporation system to reduce the volume of the FGD wastewater and then mixes the concentrated brine slurry with dry fly ash and disposes of it in a landfill.

Combination of Wet and Dry FGD Systems

Operating combined wet and dry FGD systems on the same unit or at the same plant can eliminate the scrubber purge associated with the wet FGD process. The dry FGD process involves atomizing and injecting wet lime slurry, which ranges from approximately 18 to 25 percent solids, into a spray dryer. The water contained in the slurry evaporates from the heat of the flue gas within the system, leaving a dry residue that is removed from the flue gas by a fabric filter (i.e., baghouse) [Babcock and Wilcox, 2005]. By operating a combination wet and dry FGD system, the plant can use the FGD wastewater associated with the wet FGD system as make-up water for the lime slurry feed to the dry FGD process, thereby eliminating the FGD wastewater [McGinnis, 2009].

From its data collection activities, EPA identified three plants expected to operate dry and wet FGD systems in combination on existing or planned units, eliminating the need to discharge the wastewater associated with the wet FGD system [ERG, 2013g].

Underground Injection

Underground injection is a technique used to dispose of wastes by injecting them into an underground well, an alternative to discharging wastewater to surface waters. One plant began using underground injection to dispose of FGD wastewater in 2007, but it has not been successful. Due to unexpected pressure issues and problems with building the wells due to geological formations encountered (unrelated to the characteristics of the FGD wastewater), the plant has not been able to continuously inject the wastewater. The plant operates a chemical precipitation system as pretreatment for the injection system.[37] When it is not injecting the FGD wastewater, the plant transfers the effluent from the chemical precipitation system to the cooling lake, which does not discharge to surface water (e.g. zero discharge) [ERG, 2013A**;** ERG, 2013g]. Another plant also began injecting the FGD wastewater underground in 2010 [ERG, 2013g]. Underground injection is currently managed under the Underground Injection Control (UIC) program. Underground disposal of FGD wastewater constitutes zero discharge to waters of the United States.

[37] Plant operates an iron coprecipitation system.

7.1.7 Other Technologies Under Investigation

EPRI is conducting industry-funded studies to evaluate and demonstrate technologies that can potentially remove trace metals from FGD wastewater. EPRI conducted pilot- and full-scale optimization field studies on some technologies already used by coal-fired power plants to treat FGD wastewater, such as chemical precipitation (organosulfide and iron coprecipitation), constructed wetlands, and an anoxic/anaerobic biological treatment system. EPRI is also conducting laboratory- and pilot-scale studies for other technologies that can potentially remove metals from FGD wastewaters, which include iron cementation, reverse osmosis, absorption media, ion exchange, and electro-coagulation. EPA discusses each of these technologies below.

Iron and Sulfide Additives with Microfiltration

EPRI conducted bench- and pilot-scale testing of a process to aid in removing mercury from FGD wastewater. This process involved iron coprecipitation (e.g., ferric chloride addition) and organosulfide addition, common in currently operating chemical precipitation systems, but added microfiltration to determine if that would improve solids removal over conventional clarification and media filtration. Microfiltration typically targets removing particles between 0.1 and 2 microns. Incorporating sludge recirculation theoretically increases particle size of the resulting precipitates, resulting in better solids removal in conjunction with microfiltration. EPRI determined that adding microfiltration may help remove fine-particle mercury that passes through media filters [EPRI, 2009a].

Iron Cementation

EPRI conducted bench-scale testing of the metallic iron cementation treatment technology as a way to remove all species of selenium from FGD wastewater. EPRI believes this process may also effectively remove mercury. The iron cementation process consists of contacting the FGD wastewater with an iron powder, which reduces selenium to its elemental form (i.e., cementation). The pH of the wastewater is then raised to form metal hydroxides, and the wastewater is filtered to remove the precipitated solids. The iron powder used in the process is separated from the wastewater and recycled back to the cementation step. From the initial studies, EPRI concluded that the metallic iron cementation approach is promising for treating FGD wastewater for multiple species of selenium, including selenite, selenate, and other unknown selenium compounds [EPRI, 2008b].

EPRI continued its study of iron cementation by specifically designing a pilot-scale system to remove selenium and installing the prototype at a plant burning coal from the powder river basin with FGD wastewater containing high levels of total dissolved solids (TDS), sulfate, magnesium, nitrate/nitrite-nitrogen, and selenium. Additionally, EPRI evaluated the effectiveness of the pilot-scale treatment system under continuous flow conditions. The study showed that iron cementation does reduce selenium, specifically at a lower pH and a greater hydraulic retention time. EPRI stated that increasing the hydraulic retention time improves the dissolution of the metallic selenium ion. The study results also show that selenium removal and iron dissolution are directly related; however, the pilot-scale system was unable to duplicate the selenium removal levels observed in the previous bench-scale testing described above. Under ideal operating conditions, the bench-scale testing showed that iron cementation reduced dissolved selenium to less than 0.05 mg/L; however, the pilot-scale testing's lowest selenium effluent concentration was 0.159 mg/L. Additionally, EPRI also evaluated mercury removals from a limited data set. EPRI found that mercury was significantly reduced (by a range of 84 to 97 percent) in the iron reactor [EPRI, 2009b].

Reverse Osmosis

Reverse osmosis systems are currently in use at steam electric power plants, usually to treat boiler make-up water or cooling tower blowdown wastewaters. EPRI identified a high-efficiency reverse osmosis (HERO™) process that operates at a high pH, allowing the system to treat wastewaters with high silica concentrations without scaling or membrane fouling because silica is more soluble at higher pHs. The wastewater undergoes a water-softening process to raise its pH before entering the HERO™ system.

Although the HERO™ system is currently in use in the industry to treat steam electric power plant cooling tower blowdown wastewater, its use for FGD wastewater is potentially limited due to the osmotic pressure of the FGD wastewater resulting from the high concentrations of chlorides and TDS [EPRI, 2007]. Although many plants may not be able to use the HERO™ system to treat FGD wastewater, some plants with lower TDS and chloride concentrations may be able to. The HERO™ system is of particular interest for treating boron in FGD wastewaters because boron becomes ionized at an elevated pH and, therefore, could be removed using a reverse osmosis system [EPRI, 2007].

Sorption Media

The drinking water industry uses sorption media to remove arsenic from the drinking water. Because of its success at removing similar pollutants found in FGD wastewater, specifically arsenic, EPRI reviewed sorption media technologies to determine whether they are applicable for treating FGD wastewater. These sorption processes adsorb pollutants onto the media's surface area using physical and chemical reactions. EPRI determined the most effective adsorbents are metal-based single-use products, which can be disposed of in nonhazardous landfills. EPRI also determined granular ferric oxide or hydroxide- and titanium-based oxides are the most prevalent adsorbent at the time of the study. Ferric- and titanium-based media effectively remove both common forms of arsenic (arsenate and arsenite) and selenium (selenite) over a wide pH range [EPRI, 2007].

EPA identified one plant that treats its FGD wastewater with a chemical precipitation system followed by a full-scale treatment unit that uses cartridge filters in combination with two sets of adsorbent media specifically designed to enhance removals of metals. After passing through three sets of cartridge filters (3-micron, 1-micron, and then 0.2 micron), the FGD wastewater passes through a carbon-based media that adsorbs mercury, and then through a ferric hydroxide-based media that adsorbs arsenic, chromium, and other metals. The adsorbent media reportedly achieves a maximum effluent concentration of 14 parts per trillion for mercury. [Smagula, 2010]

According to Siemens, the vendor of the adsorption media technology used in the full-scale operation, the capital costs for a system including the two sets of adsorption media could range from $200,000 to $2,000,000 dollars, depending on the flow rate, influent concentrations, and system configurations. Siemens estimates that the O&M costs for the carbon-based media are approximately $2 per 1,000 gallons treated and the O&M costs for the ferric hydroxide media are approximately $1 per 1,000 gallons treated. [Schultz, 2013]

Ion Exchange

Ion exchange systems are currently in use at power plants to pretreat boiler make-up water. Ion exchange systems remove specific constituents from wastewater; therefore, the system can target specific metals to be removed. The ion exchange resin works by substituting one ion for another on a specific resin, which must be replaced or regenerated when full [AEP, 2010]. The typical metals targeted by ion exchange systems include boron, cadmium, cobalt, copper, lead, mercury, nickel, uranium, vanadium, and zinc. Although the ion exchange process does not generate any residual sludge, it does generate a regenerant stream that contains the metals stripped from the wastewater [AEP, 2010].

In 2008, a pilot test was performed that evaluated mercury removals from filtration and ion exchange. The system was successful in removing trace mercury from FGD wastewater; however, the filtration process and not the ion exchange system removed most of the colloidal mercury [Goltz, 2009]. Additionally, EPA identified one plant that tested two ion exchange resins for treating FGD wastewater, specifically mercury removal. The plant determined that while the resin can remove dissolved mercury, it is not effective at removing particulate or colloidal mercury [AEP, 2010].

EPA identified one plant that has installed ion exchange systems to treat FGD wastewater. This plant operates a full-scale ion exchange system that selectively targets the removal of boron, in conjunction with a chemical precipitation treatment stage to remove mercury and other metals, and an anaerobic biological treatment stage to remove selenium [ERG, 2013f].

Electro-Coagulation

Electro-coagulation uses an electrode to introduce an electric charge to the wastewater, which neutralizes the electrically charged colloidal particles allowing them to precipitate out of solution. These systems typically use aluminum or iron electrodes, which dissolve into the wastestream during the process. The dissolved metallic ions precipitate with the other pollutants in the wastewater and form insoluble metal hydroxides. EPRI believes additional polymer or supplemental coagulants may need to be added to the wastewater depending on the specific characteristics. These systems are typically used to treat small wastestreams, ranging from 10 to 25 gpm, but may also be able to treat wastestreams of up to 50 or 100 gpm [EPRI, 2007].

Other Technologies

EPA obtained only limited information on other technologies under laboratory-scale study, including polymeric chelates, taconite tailings, and nano-scale iron reagents. In addition, EPRI is investigating various physical treatment technologies, primarily to remove mercury, including filtration [EPRI, 2008a].

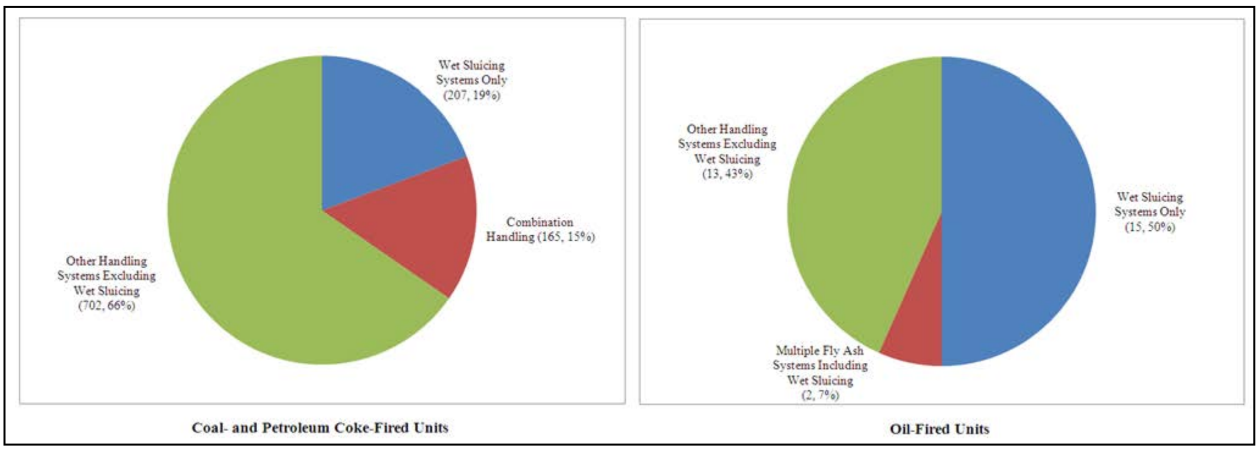
7.2 Fly Ash Handling, Management, and Treatment Technologies

During the Steam Electric Power Generating study and rulemaking, EPA identified and investigated fly ash handling systems operated by coal-, petroleum coke-, and oil-fired steam electric power plants to collect and convey fly ash, that are designed to minimize or eliminate the discharge of pollutants in fly ash handling transport water. As part of the proposed rulemaking, EPA considered chemical precipitation for the treatment of fly ash transport water. However, EPA has not identified any plants using this treatment technology to treat fly ash transport water, although EPA has reviewed two literature sources that describe laboratory- or pilot-scale tests using the technology. Upon reviewing the discharge flow rate for fly ash transport water; however, EPA determined that the capital and operating and maintenance (O&M) costs associated with treatment were comparable to the costs of converting to dry handling technologies, despite being less effective at removing pollutants. Therefore, EPA did not select chemical precipitation as a treatment technology option for fly ash in this proposed rule. A list of the fly ash handling technologies evaluated by EPA, including a brief description of each, are included below. This section describes in detail the fly ash handling technologies listed below.

- *Wet Sluicing Systems:* These systems convey fly ash wet using water-powered hydraulic vacuums that pull the fly ash from the hopper to a separator/transfer tank, where the fly ash combines with the transport water flowing through the sluice pipes. Plants usually direct the resulting sluice to a surface impoundment.
- *Wet Vacuum Pneumatic Systems:* These systems convey dry fly ash to a silo using water-powered hydraulic pumps to withdrawal fly ash from the hopper and filter-receivers to collect the fly ash dry.
- *Dry Vacuum Systems:* System that uses a mechanical exhauster to move air, below atmospheric pressure, to pull the fly ash from the hoppers and convey it directly to a silo.
- *Pressure Systems:* These systems convey dry fly ash to a silo using air produced by a positive displacement blower directly to a silo.
- *Combined Vacuum/Pressure Systems:* These systems use a dry vacuum system to pull ash from the hoppers to a transfer station, where is introduced to a high pressure conveying line that conveys the dry ash directly to a silo.
- *Mechanical Systems:* Manual or systematic systems plant's operating units with a low volume of fly ash operate remove fly ash from the hopper.

Coal-, petroleum coke-, and oil-fired power plants use particulate control technologies such as electrostatic precipitators (ESPs), baghouse filters, or venturi-type wet scrubbers to remove fly ash particles from the flue gas. Section 4 discusses the various types of fly ash collection methods used in the Steam Electric Industry. After collection, fly ash particles transfer to hoppers where plants transport fly ash via wet sluicing, dry handling, or a combination of both to its next destination. From information provided in the Steam Electric Survey, EPA determined that 481 coal-, petroleum coke-, and oil-fired power plants, corresponding to 1,074 coal- and petroleum coke-fired units and 30 oil-fired units, generate fly ash. Most of these plants (approximately 70 percent) currently transport fly ash from all of their coal-, petroleum coke-, or oil-fired steam electric generating units using dry handling systems or other processes that do not require wet sluicing. As shown in Figure 7-6, approximately 19 percent of coal- and petroleum coke-fired units operate wet sluicing only systems to collect fly ash, whereas half of the oil-fired units operate wet sluicing systems. Based on survey responses, the numbers of plants wet sluicing fly ash will decline by 2014. From survey data, EPA identified nine plants (corresponding to 18 coal-fired units) operating wet sluicing systems that will convert from wet to all dry handling operations by January 2014. Additionally, from publicly available data, ERG identified another eight plants, corresponding to 39 coal-fired units, that announced they will convert from wet to all dry handling operations [ERG, 2013d]. Plants operating dry handling systems typically sell the collected fly ash to available markets or condition it with moisture prior to disposal in a landfill. For Figure 7-6, EPA grouped each coal- petroleum coke-, and oil-fired generating unit into one of the following three categories based on the type of fly ash handling system operated by the unit:

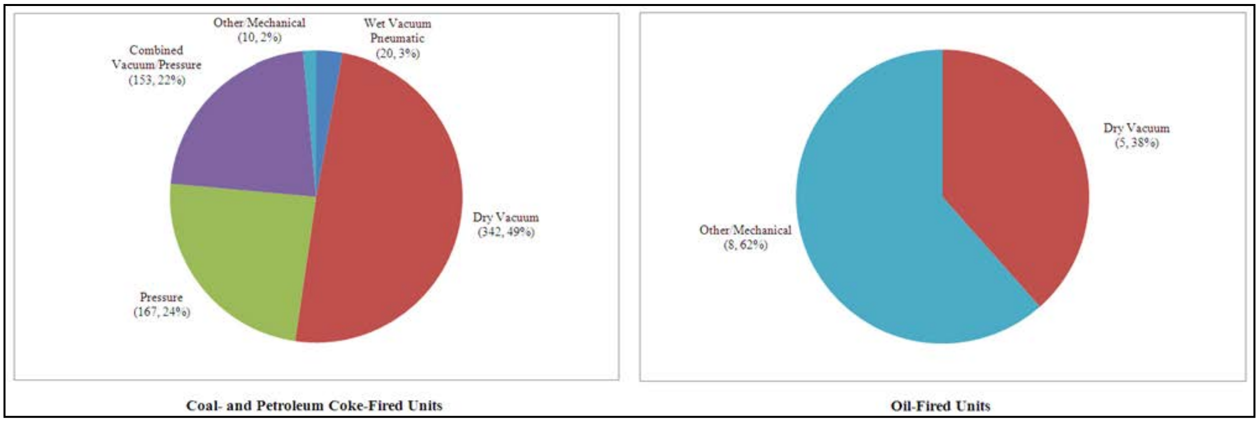
- Units with wet sluicing systems only;
- Units with any other type(s) of handling system listed above (excluding wet sluicing); and
- Units that have multiple fly ash handling systems, including wet sluicing.



Source: Steam Electric Survey [ERG, 2013g].

Figure 7-6. Distribution of Fly Ash Handling Systems for Coal-, Petroleum Coke- and Oil-Fired Units in the Steam Electric Industry

Based on information provided in the Steam Electric Survey, the number of plants installing fly ash handling systems other than wet sluicing systems on new units, or converting existing units, is increasing due to their ability to market fly ash and reduce water consumption. Excluding wet sluicing systems, the most common type of fly ash handling system currently in operation is the dry vacuum system (approximately 49 percent of non-wet-sluicing systems). Figure 7-7 shows the distribution of fly ash handling systems, excluding any units with wet sluicing systems only or units with combination wet and dry handling systems, reported in the Steam Electric Survey for coal-, petroleum coke-, and oil-fired units. EPA grouped other handling systems, mechanical systems, and a combination of multiple systems, excluding wet sluicing, as “Other/Mechanical” in Figure 7-7.



Source: Steam Electric Survey [ERG, 2013g].

Figure 7-7. Distribution of Fly Ash Handling System Types Other Than Wet Sluicing for Coal-, Petroleum Coke-, and Oil-fired Units Reported in the Steam Electric Survey

The following sections discuss fly ash handling systems currently operating in the industry, including wet sluicing systems and systems that minimize or eliminate the need for fly ash transport water.

7.2.1 Wet Sluicing System

In a wet sluicing system, water-powered hydraulic vacuums create the vacuum for the initial withdrawal of fly ash from the hoppers. The vacuum pulls the ash to a separator/transfer tank, where the fly ash combines with the transport water flowing through the sluice pipes. The sluice pipes transfer the resulting fly ash slurry to an ash impoundment. Section 6.2.3 describes wet sluicing operations in the steam electric industry in more detail.

Fly ash transport water is typically treated in large surface impoundments, either completely separate from or commingled with other combustion residual wastes. Impoundments vary in size, capacity, age, and most impoundments receive other plant wastewater (e.g., boiler blowdown, cooling water, low volume wastewater). Plants typically size the impoundments to provide enough residence time to reduce the TSS levels in the wastewater to meet the discharge requirement and to allow for a certain lifespan of the impoundment based on the expected rate of solids buildup within the impoundment.

Surface impoundments can reduce the amount of TSS in the wastewater discharge provided sufficient residence time. In addition to TSS, surface impoundments can also reduce some specific pollutants in the particulate form to varying degrees in the wastewater discharge. However, surface impoundments are not designed to reduce the amount of dissolved metals in the wastewater. While most plants discharge the overflow from the surface impoundment, some plants reuse a portion, or all, of the surface impoundment effluent as make-up for the fly ash transport water system. Additionally, some plants reuse the effluent for other plant operations. In these cases, much like discharged ash transport water, recycled transport water is often treated only via settling. Some plants, however, also have pH control systems to adjust the pH of the impoundment or the impoundment effluent stream to mitigate the potential for corrosion of the boiler and ash handling equipment.

Power plants operate and maintain the impoundments in varying ways. For example, some plants constantly remove settled ash solids from the impoundment inlet and stack them on the sides of the impoundment to dewater and build up the height of the impoundment. Alternatively, some plants periodically dredge the impoundment to remove the ash from the bottom and transfer the solids off site for disposal or to an on-site landfill, or use the solids to build up the height of the impoundment. Finally, some plants may not dredge the impoundment, but leave the ash in the impoundment permanently and, when the impoundment reaches its capacity, build a new ash impoundment and decommission the old impoundment.

7.2.2 Wet Vacuum Pneumatic System

Wet vacuum pneumatic systems are fly ash handling systems that use water-powered hydraulic vacuums to create the vacuum for the initial withdrawal of fly ash from the hoppers, similar to wet sluicing systems. However, the fly ash is not directed to a separator/transfer tank and is not combined with the water flowing through the sluice pipes. Instead, the fly ash is captured by a filter-receiver (i.e., bag filter with a receiving tank) placed before the junction where the fly ash would have been mixed with the sluice water. Wet vacuum pneumatic systems are able to convey dry ash up to 50 tons per hour (tph) and 500 feet [Mooney, 2010]. From the filter-receiver tank, the system deposits the fly ash into a silo. The silo receiving the ash is equipped with an exhauster that displaces the air from the vacuum created by the hydraulic pump and a baghouse filter that captures the fly ash in the silo.

From the silo, the fly ash is either sold to an available market or moisture conditioned and sent to a landfill. For unloading the ash for sale or conditioning, silos are usually equipped with dry unloaders, wet unloaders, or a combination of unloading equipment for each disposal method. The dry unloaders are conical shaped spouts, with a vacuum system to control fugitive dust. The system loads the ash, with a moisture content of less than one percent, from the spout into vacuum-sealed trucks, which transport the ash to the market destination. Wet unloaders use pugmills to simultaneously unload the fly ash and increase the moisture content of the ash by conditioning it with water. Pugmills condition the fly ash to between 15 and 20 percent moisture before it is unloaded into uncovered dump trucks. Responses in the Steam Electric Survey show that plants use the following types of water to moisture condition fly ash at silo locations:

- Raw intake water;
- Intake water that is treated prior to use;
- Cooling tower blowdown;
- General runoff;
- Floor drain wastewater;
- Leachate;
- Recycled process water;
- FGD wastewater; and

- Bottom ash transport water.

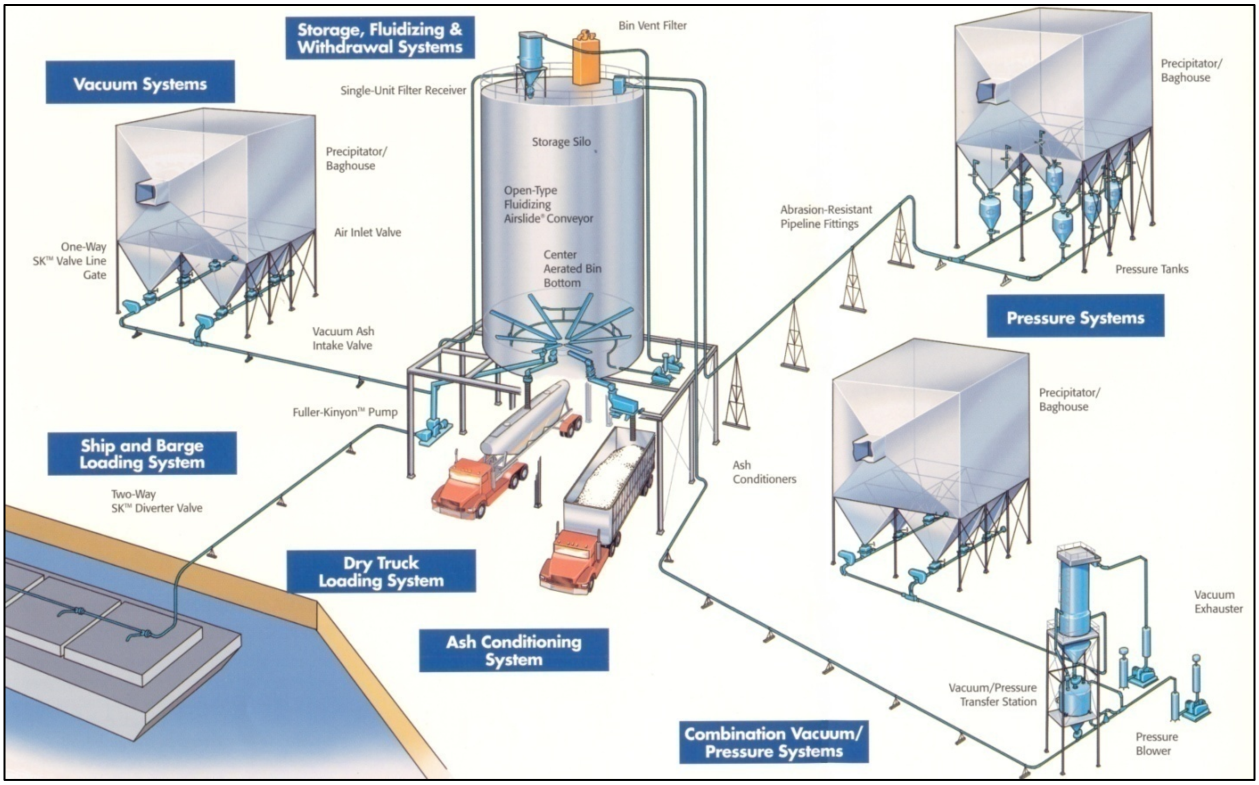
After moisture conditioning and loading, the trucks transport the ash to the landfill. Some silos are equipped with both wet and dry unloading capabilities for flexibility with the fly ash market.

The wet vacuum pneumatic system is not commonly installed on new units; however, the system is attractive to plants that are converting existing units from wet to dry fly ash handling because it allows the plants to reuse the existing vacuum source. The bag filters used to collect the fly ash prior to mixing with the vacuum water are unable to remove 100 percent of the fly ash; therefore, a small amount of fly ash contaminates the water generated from the system. Different from fly ash transport water associated with wet sluicing systems, whose purpose is to transport ash to an impoundment or other treatment, the purpose of the wet vacuum pneumatic vacuum water is strictly to create the vacuum to move the ash to the silo, and not to transport the ash to other locations outside of the system. While this stream is contaminated with a small amount of carryover fly ash, according to survey responses, most plants operating this type of system transfer the wastewater to an impoundment and reuse the overflow in the wet vacuum pneumatic system.

7.2.3 Dry Vacuum System

Dry vacuum systems use a mechanical exhauster to move air, below atmospheric pressure, to pull the fly ash from the hoppers and convey it directly to a silo. Dry vacuum systems can convey dry ash up to 60 tph and typically up to 1,000 feet [Mooney, 2010]. From discussions with fly ash handling vendors, EPA determined that some dry vacuum systems can convey ash up to 1,500 feet (at 30 to 50 tph), depending on capacity requirements, line configuration, and plant altitude [McDonough, 2011]. The fly ash empties from the hoppers into the conveying system via a material handling valve. Similar to the silo configuration described in Section 7.2.2, the silo is equipped with an aeration system and baghouse filter to receive the fly ash from the hopper. From the silo, the plant either sells the fly ash or disposes of it in a landfill. The unloading procedures described in Section 7.2.2 also apply to the dry vacuum system. See Figure 7-8 for a schematic of a typical dry vacuum fly ash handling system set-up.

Dry vacuum systems have fewer components than pressure systems, allowing for more flexibility for installing them under existing hoppers. Dry vacuum systems can also start and stop automatically during operation, due to the components and nature of the vacuum system. Vacuum systems maintain cleaner operations than other conveyance methods because any leaks simply pull ambient air into the system [Babcock and Wilcox, 2005].

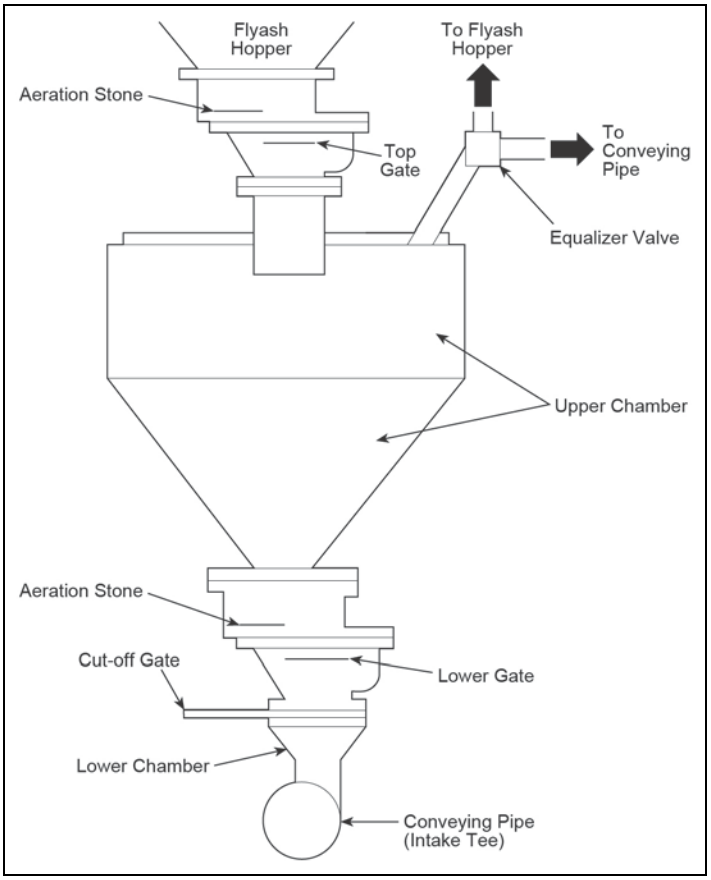


Graphic reprinted with permission from FLSmidth Inc. [FLSmidth, 2012].

Figure 7-8. Schematic of Dry Vacuum, Pressure, and Combined Vacuum/Pressure System

7.2.4 Pressure System

A pressurized system uses air produced by a positive displacement blower to convey ash directly from the hoppers to a silo. Each hopper collecting ash is equipped with airlock valves that transfer the fly ash from low pressure to high pressure in the conveying line, shown in Figure 7-9. The airlock valves are transfer points that accept ash at a low pressure, separate it from the air pressure in the bottom of the hoppers, and then release the ash to the high pressure conveying line [Babcock and Wilcox, 2005]. Once in the conveying line, the system transports the fly ash directly to the silo. Because of the high-pressure air, the aeration system at the silo is less sophisticated than those used for wet vacuum pneumatic systems (Section 7.2.2), because a vacuum is not involved in the operation. From the silo, the plant either sells the fly ash or disposes of it in a landfill. The unloading procedures described in Section 7.2.2 also apply to the pressure system. See Figure 7-8 for a schematic of a typical pressure fly ash handling system set-up.



Graphic reprinted with permission from Steve Stultz [Babcock and Wilcox, 2005].

Figure 7-9. Pressure System Airlock Valve

Plants use pressure systems to convey more ash longer distances compared to a dry vacuum systems: 100 tph of fly ash for distances up to 5,000 feet [Mooney, 2010]. Depending on the conveying capacity requirements, pressurized systems can convey ash up to 8,000 feet [McDonough, 2011]. The airlock valves (see Figure 7-9) at the bottom of the hoppers, however, require a significant amount of available headspace for installation; therefore, not all plants currently operating wet sluicing systems would be able to easily install pressure systems without significant capital investment to raise the bottom of the hopper. Additionally, pressure systems are not able to stop and start automatically because airlock valves require manual stop and restart. Pressure systems can also experience leaks of fine ash particulates, usually at the piping joints due to the high pressure in the conveying line [Babcock and Wilcox, 2005].

7.2.5 Combined Vacuum/Pressure System

Combined vacuum/pressure fly ash handling systems utilize both dry vacuum and pressure systems. A mechanical exhauster moves air, below atmospheric pressure, to pull the fly ash from the hoppers, similar to the dry vacuum system. After a short distance, approximately 800 feet or less, the system directs the fly ash to an intermediate transfer vessel, such as a filter separator, where it transfers the ash from the vacuum (low pressure) to ambient pressure. From the filter separator, the system transfers the fly ash to airlock valves that convey the ash to the high pressure conveying line. This conveying line can convey ash up to 8,000 feet [McDonough, 2011] directly to a silo. Because the second portion of the combination system is a pressure system, the aeration system at the silo is less sophisticated than for a dry vacuum system, as described above for the pressure system. From the silo, the plant either sells the fly ash or disposes of it in a landfill. The unloading procedures described in Section 7.2.2 also apply to the combined vacuum/pressure system. See Figure 7-8 for a schematic of a typical combined vacuum/pressure fly ash handling system set-up.

Plants use combination systems to transport fly ash longer distances than vacuum systems alone can, while retaining the space advantages of the dry vacuum system (i.e., no additional headspace required under the hopper). Manual stop and restart is still required to transfer fly ash from the vacuum to the pressure system. Additionally, leaks of fine ash particles will also occur at the piping joints due to the high-pressure portion of the system [Babcock and Wilcox, 2005].

7.2.6 Mechanical System

Mechanical fly ash handling systems usually service units that generate a low volume of fly ash. These units are usually oil-fired units, which typically produce less ash than coal-fired units. Mechanical systems include any manual or systematic approach to removing fly ash. Based on responses to the Steam Electric Survey, the systems include periodic scheduled cleanings of the boiler or manual removal. Manual removal procedures include scraping the sides of the boilers with sprayers or shovels, then collecting and removing the fly ash to an intermediate storage destination or sending it to a landfill.

EPA is also aware of one plant that retrofitted an oil unit with a mechanical system that included collecting fly ash with vactor trucks. A vactor truck is a vacuum with a portable pump to collect the fly ash from the roll-off dumpster. The collection system includes vacuum piping that transports fly ash in the bottom of the hoppers to a roll-off vacuum container. For plants with multiple hoppers, the fly ash is conveyed to the roll-off vacuum container one hopper at a time by closing the valves below the other hoppers. A vactor truck connects to the roll-off container, vacuums the fly ash to the truck, and disposes of the fly ash off site. Steam electric power plants can operate this system themselves or contract the vactor truck operation and off-site disposal to an outside vendor [ERG, 2013g].

7.3 Bottom Ash Handling, Management, and Treatment Technologies

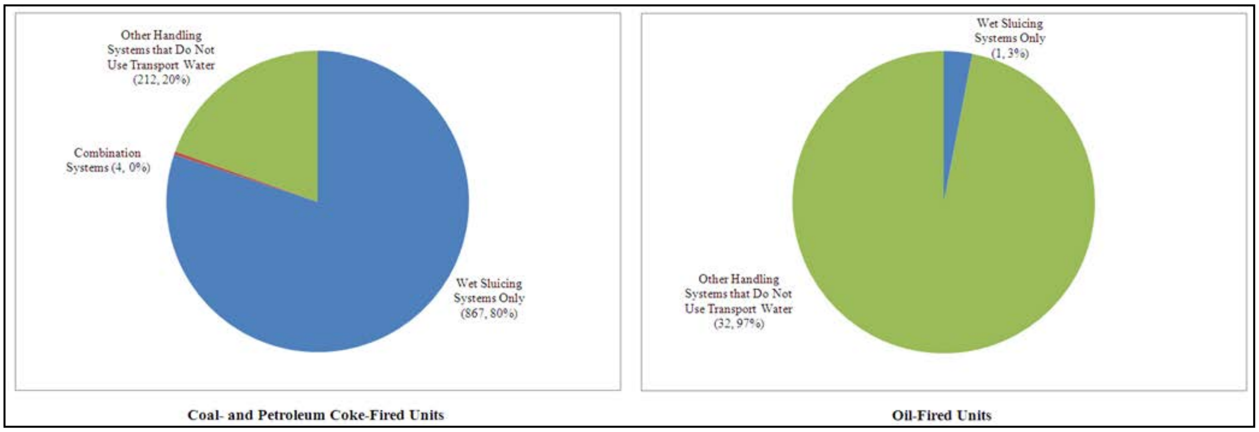
During the Steam Electric Power Generating study and rulemaking, EPA identified and investigated bottom ash handling systems operated by coal-, petroleum coke-, and oil-fired steam electric power plants to collect and convey bottom ash, that are designed to minimize or eliminate the discharge of pollutants associated with bottom ash transport water. As part of the proposed rulemaking, EPA considered chemical precipitation for the treatment of bottom ash transport water. However, upon reviewing the discharge flow rate for bottom ash transport water, EPA determined that the capital and O&M costs associated with treatment were comparable to the costs of converting to dry handling or closed-loop recycle technologies, despite being less effective at removing pollutants. Therefore, EPA did not select chemical precipitation as a treatment technology option for bottom ash in this proposed rule. A list of the bottom ash handling technologies evaluated by EPA, including a brief description of each, are included below. This section describes in detail the bottom ash handling technologies listed below.

- *Wet Sluicing Systems:* These systems convey bottom ash wet from a quench bath underneath the boiler via slurry lines. Plants usually direct the resulting sluice to a surface impoundment.
- *Mechanical Drag System*: These systems are located directly underneath the boiler. The bottom ash is collected in a water quench bath. A drag chain conveyor pulls the bottom ash out of the water bath on an incline to dewater the bottom ash.
- *Remote Mechanical Drag System*: These systems transport bottom ash using the same processes as wet sluicing systems to a remote mechanical drag system. A drag chain conveyor pulls the bottom ash out of the water bath on an incline to dewater the bottom ash.
- *Dry Vacuum or Pressure System*: These systems transport bottom ash from the boiler to a dry hopper without using any water. Air is percolated through the ash to cool it and combust unburned carbon. Cooled ash then drops to a crusher and is conveyed via vacuum or pressure to an intermediate storage destination.
- *Vibratory Belt System*: Bottom ash deposits on a vibratory conveyor trough, where the ash is air cooled and ultimately moved through the conveyor deck to an intermediate storage destination.
- *Mechanical Systems*: Manual or systematic systems plant's operating units with a low volume of bottom ash operate remove bottom ash from the hopper.
- *Complete Recycle:* Manual or systematic systems plant's operating units with a low volume of fly ash operate remove fly ash from the hopper.

From information provided in the Steam Electric Survey, EPA determined that 510 coal-, petroleum coke-, petroleum coke-, and oil-fired power plants, corresponding to 1,083 coal- or petroleum coke-fired units and 33 oil-fired units, generate bottom ash. Figure 7-10 shows a distribution of the coal-, petroleum coke-, and oil-fired units based on their type of bottom ash handling system(s). For this figure, the systems are grouped into the following three categories:

- Units with wet sluicing systems only;
- Units with systems that eliminate bottom ash transport water; and
- Units with multiple bottom ash handling systems, including wet sluicing.

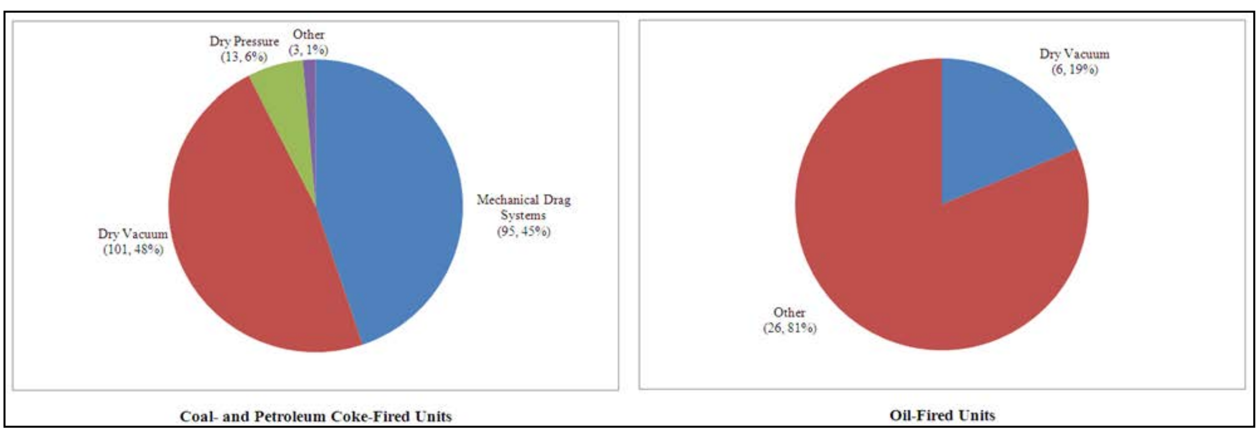
Approximately 72 percent of the 510 steam electric power plants mentioned above currently operate wet sluicing handling systems on all steam electric generating units that produce bottom ash. The remaining plants currently operate systems other than wet sluicing systems, exclusively or in combination with wet sluicing systems. As shown in Figure 7-10, approximately 80 percent of coal- and petroleum coke-fired units use only wet sluicing systems to handle bottom ash, whereas over 95 percent of oil-fired units use systems that do not use bottom ash transport water. From survey data, EPA expects approximately eight plants, corresponding to 15 coal-fired units, that operate wet sluicing systems to convert from wet to dry or closed-loop recycle systems by January 2014. Additionally, from publicly available data, EPA expects another 11 plants, corresponding to 59 coal-fired units, to convert from wet to dry or closed-loop complete system systems [ERG, 2013d]. After collecting the ash, plants can sell dewatered or dry bottom ash or send it to a landfill.



Source: Steam Electric Survey [ERG, 2013g].

Figure 7-10. Distribution of Bottom Ash Handling Systems for Coal-, Petroleum Coke-, and Oil-Fired Units Reported in the Steam Electric Survey

Information provided in the Steam Electric Survey and vendor data shows the number of plants installing mechanical drag systems on new units is increasing [McDonough, 2011]. From the Steam Electric Survey and EIA data, approximately 70 percent of steam electric generating units that began operating in the last ten to 25 years are installing handling systems other than wet sluicing. Of those systems, 55 percent are mechanical drag systems [ERG, 2013g]. Figure 7-11 shows the distribution of bottom ash handling systems, excluding units with any wet sluicing systems, reported in the Steam Electric Survey for coal-, petroleum coke-, and oil-fired units. Steam electric generating units with more than one type of bottom ash handling system, excluding wet sluicing systems, or other mechanical systems were included as "Other" in Figure 7-11.



Source: Steam Electric Survey [ERG, 2013g].

Figure 7-11. Distribution of Bottom Ash Handling System Types Other Than Wet Sluicing for Coal-, Petroleum Coke-, and Oil-Fired Units Reported in the Steam Electric Survey

Steam electric generating units that produce bottom ash collect the ash particles in hoppers, or other types of collection equipment, directly below the boilers. Generally, boilers are sloped inward and have an opening at the bottom to allow the bottom ash to feed by gravity into the ash collection system (i.e., hoppers or the trough of a mechanical drag system). The following sections discuss current bottom ash wet sluicing systems in the industry in addition to those that minimize or eliminate the discharge of bottom ash transport water.

7.3.1 Wet Sluicing System

In a wet sluicing system, bottom ash hoppers are filled with water to quench the hot bottom ash as it enters the hopper. Once the hoppers are full of bottom ash, a gate at the bottom of the hopper opens and the ash is directed to grinders to grind the bottom ash into smaller pieces (Babcock & Wilcox, 2005). As the gates at the bottom of the hoppers open, they release the bottom ash and water, emptying the water quench bath in the hopper. Once the gates are closed, the bottom of the hopper fills with water. Because of the batch style process, bottom ash removal is not continuous.

After the bottom ash passes through the grinder, the system feeds the bottom ash to the conveying line. The plant then dilutes the bottom ash with water to approximately 20 percent solids (by weight) and pumps the bottom ash slurry to an impoundment or a dewatering bin for solids removal. Section 6.2.3 describes wet sluicing operations in the steam electric industry in more detail.

Similar to fly ash transport water, bottom ash transport water is typically treated in large surface impoundments, either completely separate from or commingled with other combustion residual wastes. See Section 7.2.1 for more information on how plants typically maintain ash impoundments.

As stated above, the bottom ash slurry can either be transferred to an impoundment or a dewatering bin. For dewatering bin systems, plants usually operate two dewatering bins so that while one bin fills, the other is dewatered and the ash is unloaded into trucks or rail cars. As the bins fill with bottom ash transport water, the particulates are contained at the bottom of the bin. Excess water in the bin flows over a serrated overflow weir, leaving the dewatering bin. At the top of the bin, an underflow baffle prevents finer particulates from floating out of the bin with the overflow [Babcock & Wilcox, 2005]. As the dewatering bin continues to receive bottom ash transport water, it eventually reaches its solids loading capacity, at which time the plant directs the bottom ash transport water to another dewatering bin and begins the decant process in the first bin. The bottom ash transport water exiting the top of the bin and the water that is decanted from the bin prior to removing the solids, can either overflow to additional settling tanks or be pumped to a surface impoundment. Figure 7-12 presents a diagram of a dewatering bin system with additional settling tanks after the dewatering bins.

Graphic reprinted with permission from United Conveyor Corporation [UCC, 2009].

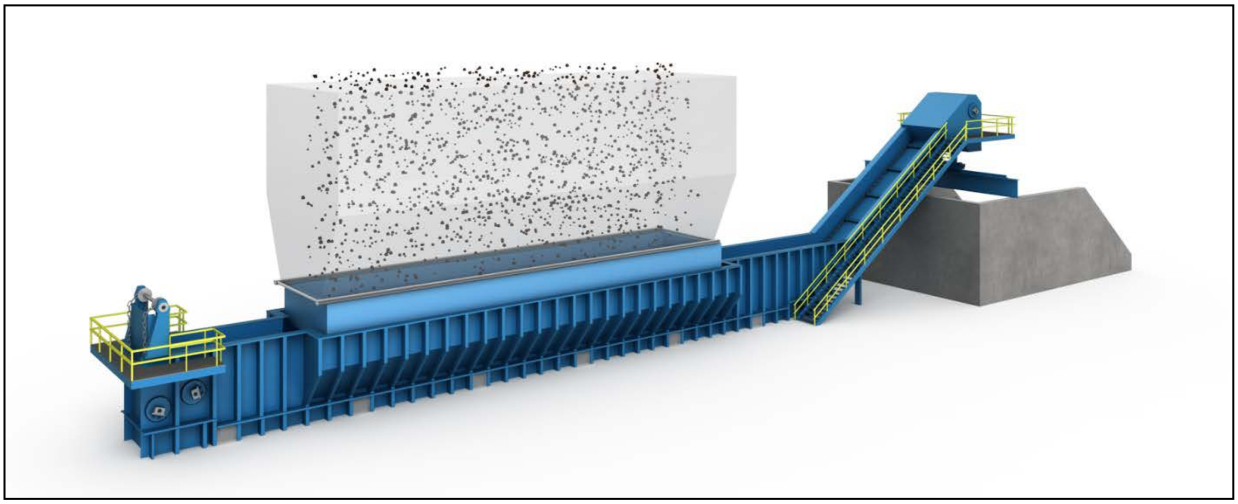
Figure 7-12. Bottom Ash Dewatering Bin System

7.3.2 Mechanical Drag System

Mechanical drag systems collect bottom ash from the bottom of the boiler, similar to the description above for the wet sluicing system. Because of the shape of the boiler, explained above, the bottom ash is gravity fed through the opening at the bottom of the boiler, through a transition chute, and into a water-filled trough. The water bath in the trough quenches the hot bottom ash as it falls from the boiler and seals the boiler gases. The drag system comprises a drag chain with a parallel pair of chains. The chains are attached with crossbars at regular intervals along the bottom of the water bath and move in a continuous loop towards the far end of the bath. At the far end, the drag chain begins moving up an incline, which dewaters the bottom ash by gravity, draining the water back to the trough as the bottom ash moves upward. Because the bottom ash falls directly into the water bath from the bottom of the boiler and the drag chain moves constantly on a loop, bottom ash removal is continuous. The dewatered bottom ash is often conveyed to a nearby collection area, such as a small bunker outside the boiler building, from which it is loaded onto trucks and either sold or transported to a landfill. See Figure 7-13 for a diagram of a mechanical drag system.

Because the trough has a water bath, the mechanical drag system does generate some water (i.e., residual water that collects in the storage area as the bottom ash continues to dewater). This wastewater, however, is typically completely recycled back to the quench water bath. Additionally, EPA does not consider this wastewater to be transport water because the transport mechanism is the drag chain, not the water.

Mechanical drag systems come in various standard widths and require little headspace under the boiler; however, the system may not be suitable for all boiler configurations. For example, existing boilers located below grade are usually surrounded with support columns and positioned close to the floor with the sluice lines 1 to 2 feet above the ground. A mechanical drag system would be difficult to install with such space limitations. Mechanical drag systems are not able to combine and collect bottom ash from multiple boilers and generally need a straight exit from the boiler to the outside of the building. These systems may also be susceptible to maintenance outages because bottom ash fragments fall directly on to the drag chain.

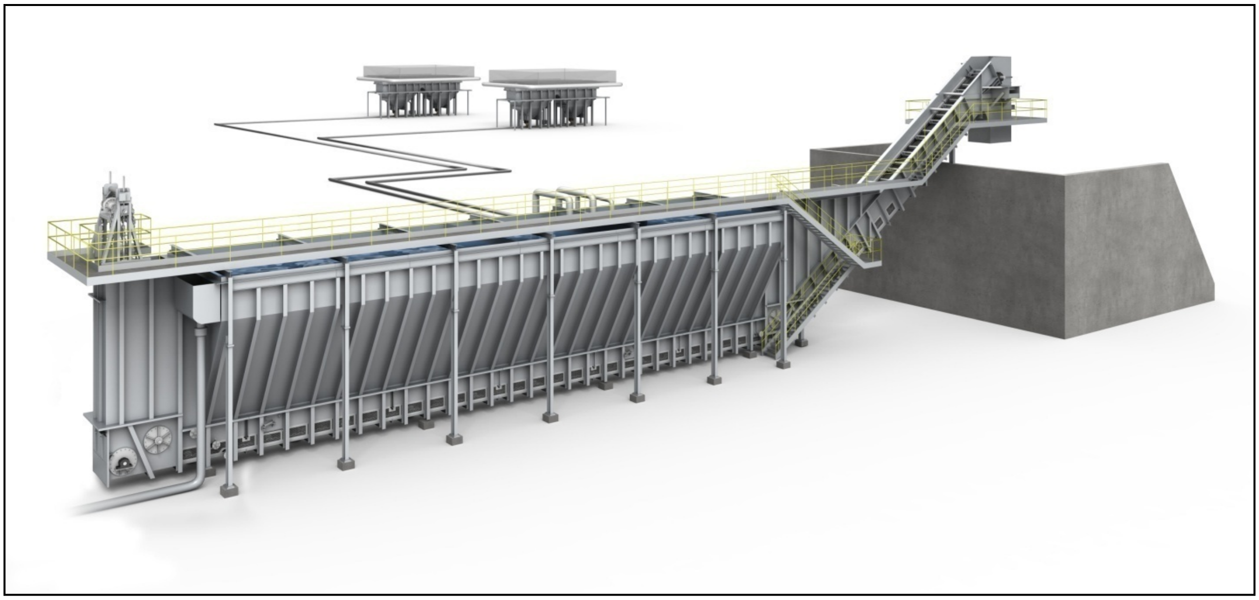


Graphic reprinted with permission from United Conveyor Corporation [UCC, 2009].

Figure 7-13. Mechanical Drag System

7.3.3 Remote Mechanical Drag System

Remote mechanical drag systems collect bottom ash using the same operations and equipment as wet sluicing systems at the bottom of the boiler. However, instead of sluicing the bottom ash directly to an impoundment, the plant pumps the bottom ash transport water to a remote mechanical drag system. This type of system has the same configuration as a mechanical drag system; however, it has additional dewatering equipment in the trough and is not located under the boiler, but rather in an open space on the plant property. See Figure 7-14 for a diagram of a remote mechanical drag system. Plants can use this system when converting existing bottom ash handling systems where space or other limitations limit the changes that can be made to the bottom of the boiler. Currently, one U.S. plant is operating and another plant is installing a remote mechanical drag system. The second system is scheduled to begin operating in 2013 [McDonough, 2012b].

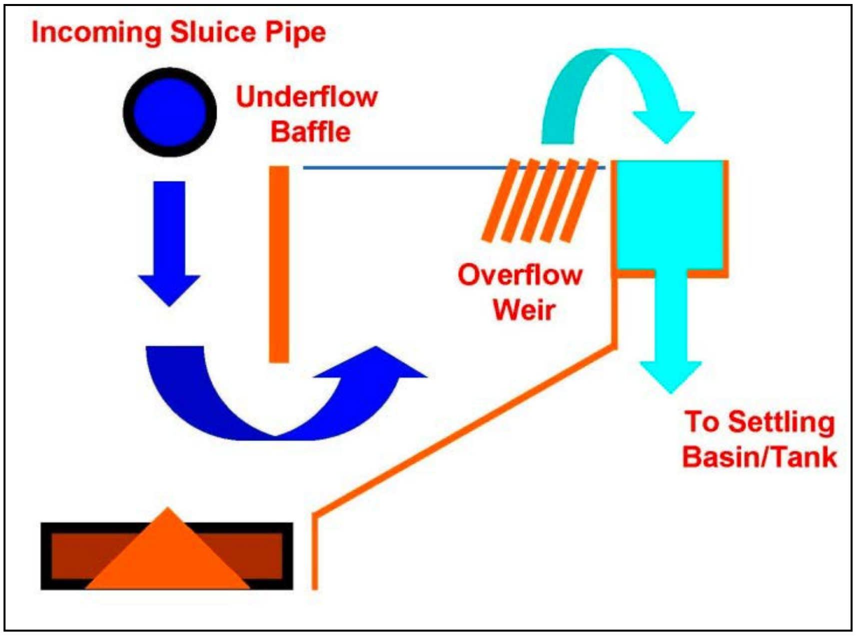


Graphic reprinted with permission from United Conveyor Corporation [McDonough, 2012a].

Figure 7-14. Remote Mechanical Drag System

The plant pumps the bottom ash transport water from the sluice pipes into the trough of the remote mechanical drag system. Similar to dewatering bins (see Section 7.3.7), an underflow baffle prevents the finer particles from exiting the trough with the overflow. As shown in Figure 7-15, the excess transport water in the trough flows over a serrated overflow weir, leaving the remote mechanical drag system. The plants collect this overflow water in a basin/sump and reuse it in the bottom ash handling system. Because of the chemical properties of bottom ash sluice, some plants may have to install a pH adjustment system to treat the overflow prior to recycle to prevent scaling and fouling in the system. Similar to the mechanical drag system, the drag chain conveys the ash to a collection area and the plant then sells the ash or disposes of it in a landfill.

The settled bottom ash is removed from the trough using the same drag system described in Section 7.3.2. The bottom ash can be loaded directly onto trucks and either sold or transported to a landfill. Remote mechanical drag systems are larger than mechanical drag systems located at the bottom of the boiler, for comparative units, because the remote systems receive excess water that must be separated from the bottom ash. Additionally, the remote mechanical drag systems can service multiple units [Fleming, 2011].



Graphic reprinted with permission from Clyde Bergemann Power Group [CBPG, 2012].

Figure 7-15. Water Flow Inside the Remote Mechanical Drag System Trough

The remote mechanical drag system essentially combines a mechanical drag system and a dewatering bin. However, because the remote mechanical drag system is located away from the boiler and is close to the ground, unlike a traditional dewatering bin, there is little increase in the total dynamic head requirements on the existing pumps and no additional water requirements compared with a traditional wet sluicing system. Also, because the remote mechanical drag system is not located underneath the boiler and the bottom ash particles have already been through a grinder, these systems require less maintenance than mechanical drag systems [Fleming, 2011]. The plant then sells the ash or disposes of it in a landfill. Unlike the mechanical drag system, remote mechanical drag systems are not located at the bottom of the boiler and therefore requires water to transport ash to the system. The water associated with the remote mechanical drag system is ash transport water because, like a sluicing system, the water is the transport mechanism that moves the bottom ash away from the hoppers.

7.3.4 Dry Vacuum or Pressure System

Dry vacuum or pressure bottom ash handling systems transport bottom ash from the bottom of the boiler into a dry hopper, without using any water. The system percolates air into the hopper to cool the ash, combust additional unburned carbon, and increase the heat recovery to the boiler. Periodically, the grid doors at the bottom of the hopper open to allow the ash to pass into a crusher that crushes the bottom ash into smaller pieces. The system then conveys the crushed bottom ash by vacuum or pressure to an intermediate storage facility [UCC, 2009]. Figure 7-16 presents a typical dry vacuum or pressure bottom ash handling system.

Dry vacuum or pressure systems eliminate water requirements and improve heat recovery and boiler efficiency. These systems are also less complicated to retrofit to existing units because there are less structural limitation (e.g., headspace requirements below the boiler) and the systems can be installed to collect bottom ash from multiple boilers (e.g., one intermediate storage facility for multiple units). The plant then sells the ash or disposes of it in a landfill.

Graphic reprinted with permission from United Conveyor Corporation [UCC, 2009].

Figure 7-16. Dry Vacuum or Pressure Bottom Ash Handling System

7.3.5 <u>Vibratory Belt System</u>

Vibratory belt systems feed bottom ash by gravity from the bottom of the boiler directly to a vibratory conveyor trough supported by coil springs, which reduce the stress of impact from the falling bottom ash. The vibratory conveyor produces an oscillatory toss-and-catch motion, transporting bottom ash in a series of successive throws. With each throw, the ash moves up and forward onto the conveyor deck. Controlled forced draft air enters through the vibratory conveyor deck to cool, suspend, and enhance oxidation of unburned carbon. The forced draft air surrounds the entire ash surface creating a fluidized bed of ash, which is conveyed to an intermediate storage destination. The plant then sells the ash or disposes of it in a landfill [UCC, 2009]. See Figure 7-17 for the layout of a vibratory bottom ash handling system.

The vibratory system eliminates water requirements and has the lowest power consumption of all other bottom ash handling systems. Additionally, unlike other bottom ash handling systems, the vibratory system does not have any moving or hinged joints that can become damaged from falling boiler slag, decreasing the chance of unscheduled outages for maintenance [UCC, 2009].

Graphic reprinted with permission from United Conveyor Corporation [UCC, 2009].

Figure 7-17. Vibratory Bottom Ash Handling System

7.3.6 Mechanical System

Similar to fly ash handling systems, mechanical bottom ash handling systems usually service units that generate low volumes of bottom ash, or handle fly and bottom ash together. These units are usually oil-fired units, which typically produce less ash than coal-fired units. Mechanical systems include any manual or systematic approach to removing bottom ash. Based on responses to the Steam Electric Survey, the systems can include periodic scheduled boiler cleanings or manual ash removal. Both procedures involve scraping the sides of the boilers with sprayers or shovels, then collecting and removing the bottom ash to an intermediate storage destination. Some plants store the manually collected ash in an ash impoundment, while others sell or dispose of the ash in a landfill.

7.3.7 Complete Recycle System

Complete recycle bottom ash systems transport bottom ash via water, using the same process as wet sluicing systems, but all the water that leaves the system is recycled back to the bottom of the boiler and/or used as make-up to the bottom ash sluicing system. Because the bottom ash is hot and evaporates a portion of the water in the quench bath, the bottom ash sluicing system is a net consumer of water, which allows the system to completely reuse all the water along with a make-up stream. The complete recycle system can operate using several different configurations. The most common configuration in the industry is to operate with dewatering bins (described in Section 7.3.1) with the overflow pumped to an impoundment and the overflow from the impoundment being pumped back to the bottom ash sluice system. There are also several other configurations that achieve complete recycle using tank-based systems that do not include impoundments. These tank-based systems can either use dewatering bins or a remote MDS. For a dewatering bin complete recycle system, the overflow and decant are transferred to additional settling tanks prior to being recycled back to the bottom ash sluice system, as shown in Figure 7-12. In the settling tank, a large percentage of the fine ash carryover settles to the bottom and is pumped to the dewatering bin for removal. The plant directs the overflow from the settling tank to the surge tank, where recirculation pumps return the water to the existing bottom ash handling system or as make-up water to the quench water bath. For a remote MDS complete recycle system, the overflow water is collected in a sump prior to being recycled back to the bottom ash sluice system. Fine ash that carries over into the sump will collect at the bottom of the sump and the plant will need to collect this material occasionally and dispose of it off site or in a landfill.

Some complete recycle systems may need to add chemical treatment, specifically pH control, for the overflow/decant water because of the chemical properties in the water. The chemical treatment may be necessary to eliminate any scaling or fouling caused by the recycled water.

Plants that install complete recycle systems on existing wet sluicing units can reuse all of the existing wet sluicing equipment. These systems also allow plants to handle bottom ash from multiple boilers. However, because of the amount of equipment and water these systems use, complete recycle systems have the highest equipment, maintenance, and power consumption requirements of all other bottom ash handling systems.

Alternatively, plants can achieve complete recycle systems using impoundment systems. Some plants discharge the ash to an impoundment, or series of impoundments, to settle and then return all effluent from the impoundment, or impoundment system, to the boiler to use as transport water. These plants often add additional make-up water to the system to compensate for any water lost due to evaporation or water retained in the ash.

7.4 COMBUSTION RESIDUAL LEACHATE

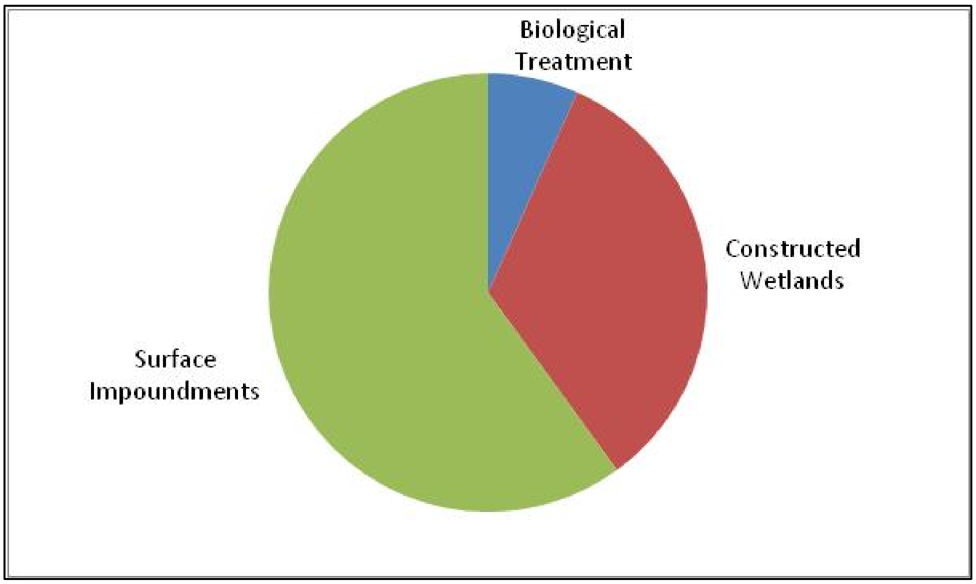
During the rulemaking, EPA identified and investigated wastewater treatment systems and management practices in use by steam electric power plants to treat leachate collected from landfills and impoundments containing combustion residual wastes. From industry profile information and leachate characterization data, described in Sections 4.3.5 and 6.3, EPA determined that combustion residual leachate from landfills and impoundments includes similar types of constituents as FGD wastewater. However, EPA determined that concentrations of the constituents in combustion residual leachate are generally lower than in FGD wastewater, especially for TDS. Based on this characterization of the wastewater, EPA believes that certain treatment technologies identified for FGD wastewater, as described in Section 7.1, could also be used to treat leachate from landfills and impoundments containing combustion residual wastes.

Additionally, EPA used information from the Steam Electric Survey, site visits, and industry profile to identify wastewater treatment systems and management practices currently used, or considered, to treat and manage combustion residual landfill and impoundment leachate. The wastewater treatment technologies that EPA identified to treat combustion residual leachate include:

- Surface impoundments;
- Chemical precipitation;

- Biological treatment (anoxic/anaerobic system with fixed film bioreactors); and
- Constructed wetlands.

In the Steam Electric Survey, EPA requested a subset of coal-fired power plants to provide information on combustion residual leachate treatment systems and management practices used in the industry. From the treatment information received, EPA determined that surface impoundments are the most commonly used system to treat combustion residual leachate from landfills and impoundments [ERG, 2013g]. Figure 7-18 shows the distribution of combustion residual leachate treatment technologies reported in the Steam Electric Survey or determined by EPA through industry contacts, for the 29 plants that reported treatment systems for combustion residual landfill and impoundment leachate.



Source: Steam Electric Survey [ERG, 2013g, WVDEP, 2010].

Figure 7-18. Distribution of Treatment Systems for Leachate from Landfills and Impoundments Containing Combustion Residual Wastes

Additionally, EPA investigated the management practices for combustion residual leachate from landfills and impoundments. From information in the Steam Electric Survey, EPA determined that 14 plants collect their combustion residual landfill leachate and use it as water for moisture conditioning dry fly ash prior to disposal or dust control around dry unloading areas and landfills.[38] EPA also identified one plant that uses the collected leachate as truck wash and routes it back to an impoundment at the plant.

EPA also identified different management practices for combustion residual impoundment leachate. From the Steam Electric Survey, EPA identified approximately 36 percent of plants collecting combustion residual impoundment leachate recycle the leachate directly back to the impoundment from which it was collected. In this case, because the

[38] EPA also identified three additional plants that use leachate for moisture conditioning fly ash and/or dust control; however, EPA was unable to determine if the wastewater is combustion residual landfill or impoundment leachate.

wastewater originated from the impoundment, the collection system is essentially just capturing a portion of the impoundment wastewater and EPA does not consider the wastewater recycled directly back to the impoundment as a new wastestream entering the pond. Instead, EPA considers it to be the same as the wastewater that is already contained within the impoundment system. However, if any of this collected wastewater is transferred to any other process or operation, then EPA would consider this a new wastestream that is subject to the proposed effluent limitations for combustion residual leachate. EPA also determined that seven plants collect their combustion residual impoundment leachate and use it as water for moisture conditioning dry fly ash prior to disposal or dust control around dry unloading areas and landfills.[39]

7.5 Flue Gas Mercury Control Wastewater Treatment Technologies

During the rulemaking, EPA identified and investigated wastewater treatment systems operated by steam electric power plants to treat wastewater generated from FGMC, as well as operating/management practices used to reduce the wastewater discharge. As described in Section 4.3.4, the installation of these systems is relatively new to the industry.

Generally, there are two types of FGMC systems, addition of oxidizers to the coal prior to combustion, and injection of activated carbon into the flue gas upstream or downstream of the primary particulate control system. FGMC systems that add oxidizers simply collect the oxidized mercury with the wet FGD system. This does not generate a new wastewater stream; however, it may increase the concentration of mercury in the FGD wastewater because the oxidized mercury is more easily removed by the FGD system.

In activated carbon injection (ACI) systems, the steam electric power plant injects activated carbon either before or after primary particulate control. If activated carbon is injected prior to the primary particulate control system, the adsorbed mercury is collected with the fly ash and handled according to the technologies described in Section 7.2, including wet sluicing. However, if the activated carbon is injected after the primary particulate control system, the plant must install a different handling system to handle the FGMC waste. Similar to Section 7.2, these systems include:

- *Wet Sluicing System:* These systems use water-powered hydraulic vacuums to create the vacuum for the initial withdrawal of fly ash from the hoppers. The FGMC waste is combined with the water used to create the vacuum and then pumped to an ash impoundment.
- Wet Vacuum Pneumatic System: These systems use water-powered hydraulic vacuums to create the vacuum for the initial withdrawal of fly ash from the hoppers, similar to wet sluicing systems; however, the fly ash is directed to a silo and is not combined with the water flowing through the sluice pipes.

[39] EPA also identified three additional plants that use leachate for moisture conditioning fly ash and/or dust control; however, EPA was unable to determine if the wastewater is combustion residual landfill or impoundment leachate.

- Dry Vacuum System: These systems use a mechanical exhauster to move air, below atmospheric pressure, to pull the fly ash from the hoppers and convey it directly to a silo.
- Pressure System: These systems use air produced by a positive displacement blower to convey ash directly from the hopper to a silo.
- Combined Vacuum/Pressure System: These systems first utilize a dry vacuum system to pull ash from the hoppers to a transfer station, and then use a positive displacement blower to convey the ash to a silo.
- Mechanical System: These systems include any manual or systematic approach to removing fly ash, such as scraping the sides of the boilers with sprayers or shovels, then collecting and removing the fly ash to an intermediate storage destination or disposal.

Based on responses to the Steam Electric Survey, EPA identified 73 power plants that operate ACI systems. As discussed in Section 6, 15 of these power plants inject the activated carbon downstream of the primary particulate removal system and the remaining 58 plants inject the activated carbon upstream of the particulate removal system [ERG, 2013g]. The following describes how these plants handle their FGMC wastes:

- Of the downstream ACI systems, only one plant handles the FGMC waste wet. The plant identified a planned FGMC system and indicated that the waste will be sluiced to a zero discharge impoundment from which solids are landfilled and wastewater is recycled within the plant;
- The remaining 14 downstream ACI systems handle the FGMC waste dry;
- Of the upstream ACI systems, five plants handle the FGMC waste wet. These plants indicated that the waste will be wet sluiced to an impoundment from which solids are landfilled and wastewater is potentially discharged;[40]
- The remaining 53 upstream ACI systems handle the FGMC waste dry.

7.6 GASIFICATION WASTEWATER TREATMENT TECHNOLOGIES

During the rulemaking, EPA identified and investigated wastewater treatment systems operated by steam electric power plants to treat wastewater generated at IGCC plants from the gasification process, as well as operating/management practices used to reduce the wastewater discharge. This section describes the following technologies:

- Vapor-compression evaporation system; and
- Cyanide destruction.

EPA is aware of two plants that currently operate IGCC units in the United States, and another plant that is scheduled to begin commercial operation in 2012. All three of these plants

[40] Four of these plants do not discharge any flue gas mercury control wastewater; however, one plant does discharge the flue gas mercury control wastewater. This one plant has the capability to handle the fly ash and FGMC waste using a dry system, but sometimes uses the wet system instead.

currently treat or plan to treat the IGCC wastewaters with vapor-compression evaporation systems. One of these plants plans to install a cyanide destruction system in addition to a vapor-compression evaporation system.

7.6.1 Vapor-Compression Evaporation System

As described in Section 7.1.4, plants can use vapor-compression evaporation systems to treat FGD wastewater and cooling tower blowdown. Additionally, the plants currently operating IGCC units are using vapor-compression evaporation systems to treat the IGCC wastewaters generated. The treatment system set-up is the same as that described for treating FGD wastewater, as discussed in Section 7.1.4; however, unlike the system used to treat FGD wastewater, the gasification wastewater does not require the pretreatment chemical precipitation and softening steps.

This vapor-compression evaporation system uses a falling-film evaporator (or brine concentrator) to produce a concentrated wastewater stream and a distillate stream. The concentrated wastewater stream may be further processed in a crystallizer, spray dryer, or rotary drum dryer, in which the remaining water is evaporated, generating a solid waste product and potentially a condensate stream. The plant can reuse the distillate and condensate streams or discharge them to surface waters. Figure 7-5 presents a process flow diagram for a vapor-compression evaporation system.

7.6.2 Cyanide Destruction

Because the wastewaters from the IGCC process can contain different cyanide contaminants (e.g., selenocyanate) formed in the gasification unit, one steam electric power plants plans to use cyanide destruction to treat both the distillate and condensate effluent streams from the vapor-compression evaporation system. Cyanide destruction treatment involves adding sodium hypochlorite (i.e., bleach) to the wastewater in mixing tanks and providing enough residence time for the bleach to completely react with the cyanide present.

7.7 METAL CLEANING WASTE TREATMENT TECHNOLOGIES AND MANAGEMENT PRACTICES

During the rulemaking, EPA identified the potential for revising the ELGs to include BAT/NSPS/PSES/PSNS limitations for nonchemical metal cleaning wastes as part of this rulemaking. The rationale for this potential revision is described in Section 8.1.2.7. EPA reviewed information reported in response to the Steam Electric Survey to evaluate the management practices used to manage and treat chemical and nonchemical metal cleaning wastes.

Table 7-1 presents a summary of the destinations reported as receiving metal cleaning wastes, broken out by the type of cleaning operation, based on the information reported in response to the Steam Electric Survey.

The Steam Electric Survey data indicate that, to a large extent, chemical and nonchemical metal cleaning wastes are managed in similar fashion. For example, both types of wastes may be discharged by plants to surface water or POTWs, as reported for 39 percent of nonchemical metal cleaning wastes and 17 percent of chemical metal cleaning wastes. Both types of wastes are evaporated during the cleaning operation at some plants (29 percent for chemical metal cleaning wastes; 10 percent for nonchemical metal cleaning wastes). Other disposal methods are also used for both types of wastes, including offsite treatment, disposal wells, landfilling, and other techniques (46 percent for chemical metal cleaning wastes; 29 percent for nonchemical metal cleaning wastes).

The Steam Electric Survey data also indicate that treatment practices for chemical and nonchemical metal cleaning wastes are similar. Chemical precipitation was reported as the type of onsite treatment system for both chemical and nonchemical metal cleaning wastes (8 percent and 11 percent, respectively). Surface impoundments were also used to treat both types of wastes, with impoundments being used more frequently for nonchemical metal cleaning wastes. This is to be expected since nonchemical cleaning (i.e., without the use of chemical compounds) is likely to remove fewer pollutants from metal process equipment, resulting in lower pollutant concentrations in the wastewater and, therefore, would more easily meet the current BPT effluent limits with surface impoundments (i.e., gravity settling). The data from the Steam Electric Survey indicate, however, that some chemical metal cleaning wastes are also sufficiently treated by surface impoundments.

EPA has also conducted a review of permits to identify how discharges of nonchemical metal cleaning wastes are being regulated in NPDES permits. To conduct this permit review, EPA used responses to the Steam Electric Survey to identify plants that reported generating chemical and nonchemical metal cleaning wastes. EPA provided the listing of these plants to the EPA Regional offices and asked them to review permits for the following:

1. How is the metal cleaning waste handled at the plant? Is there any distinction between chemical cleaning waste and nonchemical cleaning waste? If so, what are the limits for each?
2. How is the nonchemical cleaning waste handled at the plant, as metal cleaning waste or low-volume waste? What is the limit used?
3. If the non-chemical cleaning waste is handled as low-volume waste, what is the basis for this assumption? Does the factsheet make any specific reference to the 1975 EPA “Jordan Memo” or provide other justification?

EPA’s Regional offices reviewed permits for 56 steam electric power plants, 45 of which are for plants believed to generate nonchemical metal cleaning wastes, based on responses to the Steam Electric Survey. For the 45 plants believed to generate nonchemical metal cleaning wastes, EPA determined the following:

- 64 percent of the plants either do not discharge metal cleaning wastes or have to comply with effluent limits for copper and iron;
- Permits for 27 percent of the plants do not include effluent limits for copper and iron; and

- Permits for nine percent of the plants do not include enough information to determine whether the plant already operates in a manner that would be in compliance with the proposed BAT limitations.

See the memorandum entitled “Nonchemical Metal Cleaning Waste Permit Review” for additional details on the permit review and a compilation of the data received from the EPA Regional offices [ERG, 2013e].

Table 7-1. Destination of Metal Cleaning Wastewaters

Cleaning Operation	Immediately Recycled Back to Plant	Transferred to Onsite Treatment System				Discharged to Surface Water or POTW	Evaporated During Cleaning Operation	Other Disposal Method[b]
		Surface Impoundment	Chemical Precipitation	Constructed Wetland	Other[a]			
Non-Chemical Cleaning Operations	**4%**	**58%**	**11%**	**<1%**	**2%**	**39%**	**10%**	**29%**
Air Compressor Cleaning	NA	NA	NA	NA	NA	NA	NA	NA
Air-Cooled Condenser Cleaning	[c]	[c]	[c]	[c]	[c]	[c]	[c]	[c]
Air Heater Cleaning	6%	72%	15%	<1%	3%	51%	5%	21%
Boiler Fireside Cleaning	6%	70%	10%	0%	2%	50%	<1%	29%
Boiler Tube Cleaning	0%	30%	15%	0%	4%	41%	26%	19%
Combustion Turbine Cleaning (Combustion)	0%	0%	0%	0%	0%	0%	50%	50%
Combustion Turbine Cleaning (Compressor)	0%	2%	0%	0%	7%	7%	78%	9%
Condenser Cleaning	[c]	37%	0%	0%	0%	61%	11%	21%
Draft Fan Cleaning	0%	64%	64%	36%	36%	0%	0%	36%
Economizer Cleaning	0%	69%	69%	0%	6%	69%	0%	19%
FGD Equipment Cleaning	[c]	35%	0%	0%	0%	0%	0%	0%
Heat Recovery Steam Generator Cleaning	NA	NA	NA	NA	NA	NA	NA	NA
Mechanical Dust Collector Cleaning	0%	50%	93%	0%	7%	50%	0%	0%
Nuclear Steam Generator Cleaning	NA	NA	NA	NA	NA	NA	NA	NA
Precipitator Wash	0%	100%	11%	0%	2%	42%	0%	14%
SCR Catalyst Soot Blowing	0%	0%	0%	0%	0%	0%	100%	0%
Sludge Lancing	0%	44%	0%	0%	44%	0%	0%	14%
Soot Blowing	0%	22%	4%	0%	<1%	11%	25%	45%
Steam Turbine Cleaning	0%	9%	9%	0%	0%	26%	0%	43%
Superheater Cleaning	NA	NA	NA	NA	NA	NA	NA	NA
Chemical Cleaning Operations	**2%**	**17%**	**8%**	**0%**	**12%**	**17%**	**29%**	**46%**
Air Compressor Cleaning	0%	0%	0%	0%	100%	0%	0%	0%
Air-Cooled Condenser Cleaning	NA	NA	NA	NA	NA	NA	NA	NA
Air Heater Cleaning	0%	46%	0%	0%	54%	8%	0%	92%
Boiler Fireside Cleaning	0%	0%	0%	0%	44%	0%	0%	100%
Boiler Tube Cleaning	2%	21%	12%	0%	11%	13%	41%	37%
Combustion Turbine Cleaning (Combustion)	0%	0%	0%	0%	19%	54%	0%	43%

Table 7-1. Destination of Metal Cleaning Wastewaters

Cleaning Operation	Immediately Recycled Back to Plant	Transferred to Onsite Treatment System				Discharged to Surface Water or POTW	Evaporated During Cleaning Operation	Other Disposal Method[b]
		Surface Impoundment	Chemical Precipitation	Constructed Wetland	Other[a]			
Combustion Turbine Cleaning (Compressor)	2%	1%	0%	0%	11%	30%	9%	52%
Condenser Cleaning	29%	[c]	0%	0%	0%	0%	17%	17%
Draft Fan Cleaning	0%	100%	0%	0%	0%	100%	0%	0%
Economizer Cleaning	NA	NA	NA	NA	NA	NA	NA	NA
FGD Equipment Cleaning	0%	50%	0%	0%	50%	0%	0%	0%
Heat Recovery Steam Generator Cleaning	0%	0%	0%	0%	0%	0%	13%	100%
Mechanical Dust Collector Cleaning	NA	NA	NA	NA	NA	NA	NA	NA
Nuclear Steam Generator Cleaning	0%	0%	0%	0%	100%	100%	0%	0%
Precipitator Wash	NA	NA	NA	NA	NA	NA	NA	NA
SCR Catalyst Soot Blowing	NA	NA	NA	NA	NA	NA	NA	NA
Sludge Lancing	NA	NA	NA	NA	NA	NA	NA	NA
Soot Blowing	NA	NA	NA	NA	NA	NA	NA	NA
Steam Turbine Cleaning	0%	29%	8%	0%	18%	13%	27%	61%
Superheater Cleaning	0%	100%	0%	0%	0%	100%	0%	0%
Unknown	**7%**	**11%**	**12%**	**0%**	**12%**	**40%**	**7%**	**42%**
All Cleaning Operations	**3%**	**41%**	**10%**	**<1%**	**6%**	**30%**	**17%**	**36%**

Source: Steam Electric Survey, [ERG, 2013g].

Note: The percentages reported for each cleaning operation may sum to greater than 100% in some cases because all destinations for metal cleaning wastewater are identified. In some cases, wastewater can be treated and then discharged.

NA – Not applicable. The cleaning operation was not reported in the Steam Electric Survey for the type of chemical usage (i.e., nonchemical or chemical cleaning).

a – Other treatment systems include filtration, zero liquid discharge treatment, reverse osmosis, clarification, oil/water separation, and brine concentrator.

b – Other disposal methods include offsite treatment, evaporated in another generating unit, hazardous waste disposal, third-party disposal, mixed with fly ash and landfilled, and deep injection well.

c – Data were removed from certain cells to protect the release of information claimed confidential business information.

7.8 REFERENCES

1. AEP. 2010. American Electric Power Mercury Removal Effectiveness Report. (29 January). DCN SE02008.
2. Babcock & Wilcox Company. 2005. *Steam: Its Generation and Use*. 41st edition. Edited by J.B. Kitto and S.C. Stultz. Barberton, Ohio. DCN SE02919.
3. Clyde Bergemann Power Group (CBPG). 2010. "Bottom Ash Conversion Options and Economics." Diagram: ASHCON™ RSSC Design Concept." (December). DCN SE02037.
4. Eastern Research Group, Inc. (ERG). 2007. Final Engineering Site Visit Report for EME Homer City Generation L.P.'s Homer City Power Plant. (9 August). DCN SE02057.
5. Eastern Research Group, Inc. (ERG). 2008. Final Sampling Episode Report, Tennessee Valley Authority's Widows Creek Fossil Plant. (26 August). DCN SE02105.
6. Eastern Research Group, Inc. (ERG). 2010. Final Sampling Plan, Duke Energy Carolinas' Belews Creek Steam Station. (27 May). DCN SE00502.
7. Eastern Research Group, Inc. (ERG). 2012a. Final Sampling Episode Report, Duke Energy Carolinas' Allen Steam Station. (13 March). DCN SE01307.
8. Eastern Research Group, Inc. (ERG). 2012b. Final Sampling Episode Report, Allegheny Energy's Hatfield's Ferry Power Station. (13 March). DCN SE01310.
9. Eastern Research Group, Inc. (ERG). 2012c. Final Power Plant Monitoring Data Collected Under Clean Water Act Section 308 Authority ("CWA 308 Monitoring Data"). (30 May). DCN SE01326.
10. Eastern Research Group, Inc. (ERG). 2012d. Final Site Visit Notes and Sampling Episode Report for Enel's Power Plants. (8 August). DCN SE02013.
11. Eastern Research Group, Inc. (ERG). 2013a. Final Site Visit Notes for Duke Energy's Gibson Generating Station (11 March). DCN SE03622.
12. Eastern Research Group, Inc. (ERG). 2013b. Final Site Visit Notes for Kansas City Power & Light's Iatan Generating Station. (16 March). DCN SE03727.
13. Eastern Research Group, Inc. (ERG). 2013c. Final Site Visit Notes for We Energies' Pleasant Prairie Power Plant. (6 April). DCN SE00312.
14. Eastern Research Group (ERG). 2013d. Memorandum to Steam Electric Rulemaking Record. "Changes to Industry Profile for Steam Electric Generating Units for Steam Electric Effluent Guidelines Proposed Rule." (28 January). DCN SE02033.
15. Eastern Research Group, Inc. (ERG). 2013e. Memorandum to the Steam Electric Rulemaking Record: Nonchemical Metal Cleaning Waste Permit Review. (19 April). DCN SE03902.
16. Eastern Research Group, Inc. (ERG). 2013e. Site Visit Notes for GenOn Energy's Conemaugh Generating Station. (16 March). DCN SE03756.
17. Eastern Research Group, Inc. (ERG). 2013f. Steam Electric Technical Questionnaire Database ("Steam Electric Survey"). (19 April). DCN SE01958.

18. Electric Power Research Institute (EPRI). 2006. EPRI Technical Manual: Guidance for Assessing Wastewater Impacts of FGD Scrubbers. 1013313. Palo Alto, CA. (December). Available online at: http://www.epriweb.com/public/000000000001013313.pdf. Date accessed: 16 May 2008. DCN SE01817.

19. Electric Power Research Institute (EPRI). 2007. Treatment Technology Summary for Critical Pollutants of Concern in Power Plant Wastewaters. 1012549. Palo Alto, CA. (January). Available online at: http://www.epriweb.com/public/000000000001012549.pdf. Date accessed: 26 June 2008. DCN SE02922.

20. Electric Power Research Institute (EPRI). 2008a. Environment Quick News: A Monthly Report from EPRI's Environment Sector. Program 56: Effluent Guidelines and Water Quality Management. Available online at: http://mydocs.epri.com/docs/CorporateDocuments/Newsletters/ENV/QN-2008-02/ENV-QN-2008-02.pdf. Date accessed: 16 May 2008. DCN SE02923.

21. Electric Power Research Institute (EPRI). 2008b. Program on Technology Innovation: Selenium Removal from FGD Wastewaters Using Metallic Iron Cementation. Available online at: http://my.epri.com/portal/server.pt?Abstract_id=000000000001016191. Date accessed: 16 May 2008. DCN SE02924.

22. Electric Power Research Institute (EPRI). 2009a. Laboratory and Pilot Evaluation of Iron and Sulfide Additives with Microfiltration for Mercury Water Treatment. 1016813. Palo alto, CA. (March). DCN SE00409A3.

23. Electric Power Research Institute (EPRI). 2009b. Selenium Removal by Iron Cementation from a Coal-Fired Power Plant Flue Gas Desulfurization Wastewater in a Continuous Flow System – Pilot Study. 1017956. Palo Alto, CA. (July). DCN SE00409A2.

24. Fleming, Craig, et al. 2011. Telephone conversation with Craig Fleming, Gary Mooney, and Ron Grabowski, Clyde Bergemann Power Group, Ron Jordan, U.S. EPA and Elizabeth Sabol and TJ Finseth, Eastern Research Group, Inc. "Conversion Costs for Wet to Dry Bottom Ash Handling Systems."(22 June). DCN SE02020.

25. FLSmidth, Inc. 2012. Fly Ash Handling Illustration. (October). DCN SE02038.

26. Goltz, Robert, et al. 2009. Trace Mercury Removal from Flue Gas Desulfurization Wastewater. DCN SE02041.

27. Jacobs Consultancy. 2012. New Hampshire Clean Air Project Final Report Prepared for New Hampshire Public Utilities Commission. (10 September). SE02011.

28. Jordan, Ron. 2008. Site Visit Notes: Progress Energy Carolinas' Roxboro Steam Electric Plant. (7 July). DCN SE02064.

29. Loewenberg, Matthias. 2012. Zero-Liquid Discharge System at Progress Energy Mayo Generation Station. DCN SE02027.

30. McDonough, Kevin. 2011. Telephone and email communication with Kevin McDonough, United Conveyor Corporation (UCC), and Elizabeth Sabol, Eastern Research Group, Inc. "Wet to Dry Ash Handling Conversions – Fly and Bottom." (April). DCN SE02017.

31. McDonough, Kevin. 2012a. Letter from Kevin McDonough, UCC, to Jezebele Alicea, EPA, RE: Copyright Permission Request – United Conveyor Corporation (UCC®). (27 November). DCN SE02968.

32. McDonough, Kevin. 2012b. Teleconference Notes between Kevin McDonough & Mike Kippis, United Conveyor Corporation, Ron Jordan and Jezebele Alicea-Virella, EPA, and TJ Finseth and Elizabeth Sabol, Eastern Research Group, Inc. "Bottom Ash Handling Conversions in the Industry." (May). DCN SE02016.

33. McGinnis, Gregory, et al. 2009. "Cliffside 6 Integrated Emissions Control System." Power Engineering. (28 April). Available on-line at: http://pepei.pennnet.com/display_article/358960/6/ARTCL/none/none/1/Cliffside-6-Integrated-Emissions-Control-System/. DCN SE02925.

34. Michel, Tim. 2012. Telephone conversation with Michel Tim of Milestone, Inc. and Kavya Kasturi, Eastern Research Group, Inc. "Milestone's Direct Mercury Analyzers." (27 March). DCN SE02031.

35. Mooney, Gary. 2010. Telephone and email communication with Gary Mooney, Clyde Bergemann Power Group, Inc. and Elizabeth Sabol, Eastern Research Group, Inc. "Conversion from Wet to Dry Ash Handling Systems – Fly and Bottom." (18 November). DCN SE01825A69.

36. Pickett, Tim, et al. 2005. ABMet® Biological Selenium Removal from FGD Wastewater. (March). DCN SE02039.

37. Pickett, Tim, et al. 2006. "Using Biology to Treat Selenium." Power Engineering. (November). Available online at: http://pepei.pennnet.com/display_article/278443/6/ARTCL/none/none/Using-Biology-to-Treat-Selenium/. Date accessed: May 16, 2008. DCN SE02926.

38. Rao, M.N. 2008. Aquatech International Corporation. ZLD Systems Installed for ENEL Power Plants in Italy. International Water Conference. (27 - 29 October). DCN SE02927.

39. Rogers, John. et al. 2005. Specifically Designed Constructed Wetlands: A Novel Treatment Approach for Scrubber Wastewater. (September). DCN SE02928.

40. Schultz, Shelly. 2013. Teleconference Notes between Timothy Peschman, Adam Szczeniak, & Jennifer Ellis, Siemens Industry Inc., and TJ Finseth and Shelly Schultz, Eastern Research Group, Inc. "Discussion of Merrimack Station System Operation and Costs." (2 January). DCN SE03901.

41. Smagula, William. 2010. Letter from William H. Smagula, Public Service Company of New Hampshire, to John King, Office of Ecosystem Protection (U.S. EPA). "Public Service Company of New Hampshire Merrimack Station, Bow, New Hampshire Response to Informal EPA Request for Supplemental Information about Planned State-of-the-Art FGD Wastewater Treatment System." (8 October). SE02010.

42. Shaw, William A. 2008. "Benefits of Evaporating FGD Purge Water." Power. (March). 59-63. Available online at: http://www.powermag.com/powerweb/archive_article.asp?a=60-F_WM&y=2008&m=march. Date accessed: March 14, 2008. DCN SE02929.

43. Sonstegard, Jill, et al. 2010. ABMet®: Setting the Standard for Selenium Removal. (October). DCN SE02040.
44. United Conveyor Corporation (UCC). 2009. Wet-to-Dry Conversion: Bottom Ash & Fly Ash Systems. DCN SE02042.
45. U.S. EPA. 2013. Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category Report. (19 April). DCN SE01957
46. Veolia Water Solution & Technologies Company. 2007. "HPD Awarded Flue Gas Desulfurization (FGD) Effluent Treatment for Monfalcone Coal-Fired Generating Station." News Release. (16 January). DCN SE02930.
47. WVDEP. 2010. National Pollutant Discharge Elimination System Permit for American Electric Power's Mountaineer Plant (WV0048500). (6 August). DCN SE02009.

SECTION 8
TECHNOLOGY OPTIONS CONSIDERED AS BASIS FOR REGULATION

This section presents the technology options considered by EPA as the basis for the proposed effluent limitations guidelines and standards (ELGs) for the Steam Electric Power Generating Point Source Category. EPA developed technology options for the following limitations and standards:

- Best Practicable Control Technology Currently Available (BPT);
- Best Available Technology Economically Achievable (BAT);
- New Source Performance Standards (NSPS);
- Pretreatment Standards for Existing Sources (PSES); and
- Pretreatment Standards for New Sources (PSNS).

EPA is not developing Best Conventional Pollutant Control Technology (BCT) limitations for this point source category.

EPA's technology options incorporate pollutant control technologies that are demonstrated in the steam electric industry, minimize water use, and result in minimal non-water quality environmental impacts. While EPA establishes ELGs based on a particular set of in-process and end-of-pipe treatment technology options, EPA does not require a discharger to use these technologies. Rather, the technologies that may be used to treat wastewater are left entirely to the discretion of the individual plant operator, as long as the plant can achieve the numerical discharge limitations and standards, as required by Section §301(b) of the Clean Water Act (CWA). Direct and indirect dischargers can use any combination of process modifications, in-process technologies, and end-of-pipe wastewater treatment technologies to achieve the ELGs.

8.1 PROPOSED REGULATORY OPTIONS

This section discusses the regulatory options evaluated for the proposed revisions to the ELGs for each wastestream. EPA selected the technology bases for each wastestream for which it is proposing revisions to the regulation from the technologies described in Section 7. Section 8.1.1 describes BPT/BCT. The overall technology bases for the development of BAT, NSPS, PSES, and PSNS are discussed in Section 8.1.2. Sections 8.1.3 through 8.1.6 discuss the rationale for the selected technologies for each regulation. Sections 8.1.7 discusses considerations made by EPA related to future FGD installations.

8.1.1 BPT/BCT

EPA is not proposing to revise the BPT effluent guidelines or establish BCT effluent guidelines for the proposed rulemaking because the same wastestreams would be controlled at the proposed BAT/BADCT (NSPS) level of control. EPA is proposing to remove FGD wastewater, FGMC wastewater, gasification wastewater, and leachate from the definition of low-volume wastes. As a result, EPA is making a structural adjustment to the text of the regulation at

40 CFR 423 to add paragraphs that list these four wastestreams by name, along with their applicable effluent limitations. The reformatted regulatory text for these four wastestreams includes BPT effluent limits, which are the same as the current BPT effluent limits for low volume wastes.

8.1.2 Description of the Proposed BAT/NSPS/PSES/PSNS Options

EPA is proposing to revise or establish BAT, BADCT (NSPS), PSES, and PSNS that may apply to discharges of seven wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate, nonchemical metal cleaning wastes, and wastewater from FGMC systems and gasification systems. Section 7 describes the treatment technologies and operational practices that EPA reviewed during the development of this proposed rule. From these, EPA identified a subset of technologies (treatment processes and operational practices) that were most promising as candidate BAT/BADCT options. For the proposed ELGs, EPA is presenting eight main regulatory options (i.e., Option 1, Option 3a, Option 2, Option 3b, Option 3, Option 4a, Option 4, and Option 5) that represent different levels of pollutant removal associated with different wastewater streams (i.e., each succeeding option from Option 1 to Option 5 would achieve more reduction in discharges of pollutants to waters of the U.S). Table 8-1 summarizes the eight main regulatory options, which are described in the following paragraphs.

EPA is also proposing to add provisions to the ELGs that would prevent facilities from circumventing applicable ELGs. The proposed provisions would clarify the acceptable conditions for discharge of reused process wastewater and establish effluent monitoring requirements.

EPA is considering establishing BMPs that would apply to surface impoundments (i.e., ponds) that receive, store, dispose of, or are otherwise used to manage coal combustion residuals including FGD wastes, fly ash, bottom ash (which includes boiler slag), leachate, and other residuals associated with the combustion of coal to prevent uncontrolled discharges from these impoundments as described in Section 8.1.2.9.

As part of its consideration of technological availability and economic achievability for all regulatory options, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the requirements of the rule. EPA proposes that certain limitations and standards being proposed for existing sources would not apply until July 1, 2017 (approximately three years from the effective date of this rule).

EPA is also considering establishing, as part of the BAT for existing sources, a voluntary incentive program that would provide more time for plants to implement the proposed BAT requirements if they adopt additional process changes and controls that would provide significant environmental protections beyond those achieved by the preferred options in the proposed rule. Power plants would be granted two additional years (beyond the time described above in the preceding paragraph) if they also dewater, close and cap all CCR surface impoundments at the facility (except combustion residual leachate impoundments), including those surface impoundments located on non-adjoining property that receive CCRs from the facility. A power plant participating in the voluntary incentive program could continue to operate surface impoundments for which combustion residual leachate was the only type of CCR solids or wastewater contained in the impoundment. Power plants would be granted five additional years (beyond the time described above in the preceding paragraph) if they eliminate discharges of all process wastewater to surface waters, with the exception of cooling water discharges.

Table 8-1. Steam Electric Regulatory Options

Wastestreams	**Technology Basis for BAT/NSPS/PSES/PSNS Regulatory Options**							
	1	**3a**	**2**	**3b**	**3**	**4a**	**4**	**5**
FGD Wastewater	Chemical Precipitation	BPJ Determination	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment for units at a facility with a total wet-scrubbed capacity of 2,000 MW and more; BPJ determination for <2,000 MW	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Evaporation
Fly Ash Transport Water	Impoundment (Equal to BPT)	Dry handling	Impoundment (Equal to BPT)	Dry handling	Dry handling	Dry handling	Dry handling	Dry handling
Bottom Ash Transport Water	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Dry handling/ Closed loop (for units >400 MW); Impoundment (Equal to BPT)(for units ≤400 MW)	Dry handling/ Closed loop	Dry handling/ Closed loop
Leachate	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Chemical Precipitation	Chemical Precipitation
FGMC Wastewater	Impoundment (Equal to BPT)	Dry handling	Impoundment (Equal to BPT)	Dry handling	Dry handling	Dry handling	Dry handling	Dry handling
Gasification Wastewater	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation
Nonchemical Metal Cleaning Wastes[41]	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation

[41] As described in Section 8.1.3, EPA is proposing to exempt from new copper and iron BAT limitations any existing discharges of nonchemical metal cleaning wastes that are currently authorized without iron and copper limits.

8.1.2.1 FGD Wastewater

Addressing the variety of pollutants present in FGD wastewater typically requires several stages of treatment to remove the suspended solids, particulate and dissolved metals, and other pollutants present. Historically, power plants have relied on surface impoundments to treat FGD wastewater because NPDES permits generally focused on controlling suspended solids for this wastestream. Surface impoundments are the technology basis for the current BPT effluent limits (last revised in 1982) for steam electric power plants. In recent years, physical/chemical treatment systems and other more advanced systems have become more widely used as effluent limits for metals and other pollutants have been included in permits, in nearly all cases driven by the need to utilize such technologies to meet water quality-based effluent limits (WQBELs) established to meet applicable water quality standards in the receiving waters. At present, a number of steam electric plants either use chemical precipitation or chemical precipitation and biological treatment to control discharges of FGD wastes. However, surface impoundments continue to be the predominant technology used to treat FGD wastewater, with 54 percent of plants that discharge FGD wastewater relying on this technology alone (i.e., not including the plants that use surface impoundments as pretreatment for more advanced treatment). In addition, it is common for plants to commingle the surface impoundment FGD effluent with wastestreams of significantly higher flows (e.g., ash transport water and cooling water) because the higher-flow wastestreams dilute the FGD wastewater so that the resulting pollutant concentrations in the combined wastestream do not exceed the applicable water quality-based effluent limitations.

Surface impoundments use gravity to remove solid particles (i.e., suspended solids) from the wastewater. Metals in FGD wastewater are present in both soluble (i.e., dissolved) and particulate form. Some metals, such as arsenic, are often present mostly in particulate form; these usually can be removed to a substantial degree by a well-operated settling process that has a sufficiently long residence time. However, other pollutants, such as selenium, boron, and magnesium, are present mostly in soluble form and are not effectively and reliably removed by wastewater surface impoundments. For metals present in both soluble and particulate forms (such as mercury), surface impoundments will not effectively remove the dissolved fraction. Furthermore, the conditions present in some surface impoundments can create chemical conditions (e.g., low pH) that convert particulate forms of metals to soluble forms, which would not be removed by the gravity settling process in the surface impoundment. Additionally, EPRI (a technical research organization funded by the electric power industry) has reported that adding FGD wastewater to surface impoundments used to treat ash transport water (i.e., ash ponds) may reduce the settling efficiency in the impoundments due to gypsum particle dissolution, thus increasing the effluent TSS concentrations. EPRI has also reported that the FGD wastewater includes high loadings of volatile metals, which can increase the solubility of metals in surface impoundments, thereby leading to increased levels of dissolved metals and resulting in higher concentrations of metals in the discharge from surface impoundments [EPRI, 2006].

During the summer, some surface impoundments become thermally stratified. When this occurs, the top layer of the impoundment is warmer and contains higher levels of dissolved oxygen, whereas the bottom layer of the impoundment is colder and can have significantly lower levels of oxygen and may develop anoxic conditions. Typically, during fall, as the air temperature decreases, the upper layer of the impoundment becomes cooler and more dense, thereby sinking and causing the entire volume of the impoundment to circulate. Solids that have collected at the bottom of the impoundment may become resuspended due to such mixing, increasing the concentrations of pollutants discharged during the turnover period. Seasonal turnover effects largely depend upon the size and configuration of the surface impoundment. Smaller, and especially shallow, surface impoundments likely do not experience turnover because they do not have physical characteristics that promote thermal stratification. However, some surface impoundments are large (e.g., greater than 300 acres) and deep (e.g., greater than 10 meters deep) and likely experience some degree of turnover.

Technologies more advanced than surface impoundments exist and that are more effective at removing both soluble (i.e., dissolved) and particulate forms of metals, as well as other pollutants such as nitrogen compounds and TDS. Because many of the pollutants of concern for FGD wastewater are present in dissolved form and would not be removed by surface impoundments, and because of the relatively large mass loadings of these pollutants (e.g., selenium, dissolved mercury) discharged by the FGD wastestream, EPA explored other technologies that would be more effective at removing these pollutants of concern and is co-proposing three options that would include such technologies. However, for reasons discussed in Section 8.1.3, EPA is also co-proposing options under which some or all facilities would continue, for the purposes of the ELGs, to be subject to the BPT requirements based on surface impoundments for treatment of FGD wastewater. Under these options, BAT would be left to a site-specific determination. For the reasons discussed above and in Section 8.1.3, EPA does not believe that surface impoundments represent best available demonstrated control technology for controlling pollutants in FGD wastewater. Therefore, none of the regulatory options for NSPS presented in this proposal are based on the performance of surface impoundments for FGD wastewater.

The technology basis for the effluent limitations and standards for FGD wastewater in Option 1 is physical/chemical treatment consisting of the following: chemical precipitation/coprecipitation (employing the combination of hydroxide precipitation, iron coprecipitation, and sulfide precipitation). Option 1 also incorporates the use of flow minimization for plants with high FGD discharge flow rates (i.e., greater than 1,000 gpm) and FGD system metallurgy and operating practices that can accommodate an increase in chlorides (e.g., scrubber systems constructed of non-metallic materials or corrosion-resistant metal alloys, or systems operating with absorber chloride concentrations substantially below the design chloride limit). The flow minimization at these plants would be achieved by either reducing the FGD purge rate or recycling a portion of their FGD wastewater.

Physical/chemical treatment (i.e., chemical precipitation) is used to remove metals and other pollutants from wastewater. Chemicals are added to the wastewater in a series of reaction tanks to convert soluble metals to insoluble metal hydroxide or metal sulfide compounds, which precipitate from solution and are removed along with other suspended solids. An alkali, such as hydrated lime, is typically added to adjust the pH of the wastewater to the point where metals precipitate out as metal hydroxides (typically referred to as hydroxide precipitation). Chemicals such as ferric chloride are often added to the system to increase the removal of certain metals through iron coprecipitation. The ferric chloride also acts as a coagulant, forming a dense floc that enhances settling of the metal precipitate in the downstream clarification stage. Coagulants and flocculants are often added to facilitate the settling and removal of the newly formed solids. Plants trying to increase removals of mercury and other metals will also include sulfide addition (e.g., organosulfide) as part of the process. Adding sulfide chemicals in addition to hydroxide precipitation provides even greater reductions of heavy metals due to the very low solubility of metal sulfide compounds, relative to metal hydroxides. Sulfide precipitation is widely used in Europe and multiple locations in the United States have installed this technology. Forty U.S. power plants (34 percent of plants discharging FGD wastewater) include physical/chemical treatment as part of the FGD wastewater treatment system; more than half of these plants (28 percent of plants discharging FGD wastewater) use both hydroxide and sulfide precipitation in the process.

The technology basis for the effluent limitations and standards for FGD wastewater in Options 2, 3b (for units located at facilities with a total wet-scrubbed capacity of 2,000 MW or more), 3, 4a, and 4 is chemical precipitation/coprecipitation (the same technology basis under Option 1) used in combination with anoxic/anaerobic biological treatment designed to optimize removal of selenium.[42] As is the case for Option 1, these BAT options also incorporate the use of flow minimization for plants with high FGD discharge flow rates (i.e., greater than 1,000 gpm) and FGD system metallurgy and operating practices that can accommodate an increase in chlorides. The flow minimization at these plants would be achieved by either reducing the FGD purge rate or recycling a portion of their FGD wastewater.

Physical/chemical treatment systems are capable of achieving low effluent concentrations of various metals and the sulfide addition is particularly important for removing mercury; however, this technology is not effective at removing selenium, nitrogen compounds, and certain metals that contribute to high concentrations of TDS in FGD wastewater (e.g., bromides, boron). Six power plants in the U.S. are operating FGD treatment systems that include a biological treatment stage designed to substantially reduce nitrogen compounds and selenium.[43] Other industries have also used this technology to remove selenium and other pollutants. These systems use anoxic/anaerobic bioreactors optimized to remove selenium from the wastewater. The bioreactor alters the form of selenium, reducing selenate and selenite to elemental selenium, which is then captured by the biomass and retained in treatment system residuals. The conditions in the bioreactor are also conducive to forming metal sulfide complexes to facilitate additional removals of mercury, arsenic, and other metals. The information in the record for this proposed rule demonstrates that the amount of mercury and other pollutants removed by the biological treatment stage of the treatment system, above and beyond the amount of pollutants removed in the chemical precipitation treatment stage preceding the bioreactor, can be substantial. In addition, the anoxic conditions in the bioreactor remove nitrates by denitrification and, if necessary, the biological processes can be modified to include a step to nitrify and remove ammonia. Four of these six plants precede the biological treatment stage with physical/chemical treatment; thus, the entire system is designed to remove suspended solids, particulate and dissolved metals, soluble and insoluble forms of selenium, and nitrate and nitrite forms of nitrogen. The other two plants operating anoxic/anaerobic bioreactors to remove selenium precede the biological treatment stage with surface impoundments instead of chemical

[42] This value is calculated by summing the nameplate capacity for all of the units that are serviced by wet FGD systems.

[43] A seventh plant is scheduled to begin operating a biological treatment system for selenium removal next year. Another plant is installing a similar treatment system to remove selenium in discharges of combustion residual leachate [ERG, 2013c].

precipitation. While the treatment systems at these two plants would be less effective at removing metals (including many dissolved metals) than the plants utilizing chemical pretreatment, they nevertheless show the efficacy of biological treatment for removing selenium and nitrate/nitrite from FGD wastewater. Three percent of the plants discharging FGD wastewater use chemical precipitation followed by anaerobic biological treatment to treat this wastewater, which is the technology basis for Options 2, 3b (for units located at facilities with a total wet-scrubbed capacity of 2,000 MW or more), 3, 4a, and 4.

The technology basis for the effluent limitations and standards for FGD wastewater in Option 5 is chemical precipitation/coprecipitation used in combination with vapor-compression evaporation. Physical/chemical treatment systems can achieve low effluent concentrations for a number of pollutants, and reduce concentrations even further when combined with biological treatment systems. However, these technologies have not been effective at removing substantial amounts of boron and pollutants such as sodium and bromides that contribute to high concentrations of TDS. Another FGD wastewater treatment technology that can address these more recalcitrant pollutants, as well as removing the pollutants treated by physical/chemical and biological technologies, is vapor-compression evaporation. This technology uses an evaporator to produce a concentrated wastewater stream and a reusable distillate stream. The concentrated wastewater stream is either disposed of or further processed to produce a solid by-product and additional distillate. The plant can reuse the distillate stream as makeup water. Two U.S. plants and four Italian plants are operating this technology to treat FGD wastewater from their coal-fired generating units.[44]

For Option 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), EPA is proposing not to characterize a technology basis for effluent limitations and standards applicable to discharges of pollutants in FGD wastewater at this time. As illustrated above, there is a wide range of technologies currently in use for reducing pollutant discharges associated with FGD wastewater, and research continues in the development of additional technologies to treat FGD wastewater (see Section 7.1.7 for more information on emerging technologies). The more advanced technologies (those that reduce the most pollutants) reflect recent innovations in the area of treatment of FGD wastewater. EPA expects this trend to continue and, therefore, under Option 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), effluent limitations representing BAT for discharges of FGD wastewater would be determined on a site-specific best professional judgment (BPJ) basis. Under Options 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), pretreatment program control authorities would need to develop local limits to address the introduction of pollutants in FGD wastewater by steam electric plants to the POTWs that cause pass through or interference, as specified in 40 C.F.R. 403.5(c)(2).

EPA is proposing that certain limitations and standards being proposed for existing sources would apply to discharges of FGD wastewater generated on or after the date established by the permitting authority that is as soon as possible within the next permit cycle after July 1, 2017. FGD wastewater generated prior to that date (i.e., “legacy” wastewater) from existing direct dischargers would remain subject to the existing BPT effluent limits. For indirect

[44] A third U.S. plant is currently installing a vapor-compression evaporation system to treat the FGD wastewater.

dischargers, EPA is proposing that PSES for FGD wastewater would apply to FGD wastewater generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. EPA considered subjecting legacy FGD wastewater to the proposed BAT and PSES requirements. However, as explained above, FGD wastewater and its associated pollutants are typically sent to surface impoundments for treatment prior to discharge. These surface impoundments often contain other plant wastewaters, such as fly ash or bottom ash transport water, coal pile runoff, and/or low volume wastes. According to data provided by the industry survey, 78 percent of surface impoundments that receive FGD wastewater also receive fly ash and/or bottom ash transport water. EPA does not have the data to demonstrate that the technologies identified above represent BAT for legacy FGD wastewater. As such, EPA is not proposing BAT requirements associated with discharges of legacy FGD wastewater generated prior to the date established by the permitting authority (for direct dischargers) or control authority (for indirect dischargers). As proposed, discharges of legacy FGD wastewater by existing direct dischargers would remain subject to the existing BPT effluent limits; however, under some of the proposed options, EPA is also considering setting the BAT effluent limitations for legacy FGD wastewater that has not been mixed with non-legacy wastes equal to the existing BPT effluent limits. See Section 14.1.3 for additional information.

8.1.2.2 Fly Ash Transport Water

Under Options 1 and 2, BAT effluent limitations for fly ash transport water would be set equal to the current BPT effluent limitations, based on the technology of gravity settling in surface impoundments to remove suspended solids. The current effluent guidelines for existing sources include BPT effluent limits for the allowable levels of TSS and oil and grease in discharges of fly ash transport water. The BPT effluent limits are based on the performance of surface impoundments, which when well-designed and well-operated can effectively remove suspended solids, including pollutants such as particulate forms of certain metals when associated with the suspended solids.

Under Options 3a, 3b, 3, 4a, 4, and 5, EPA would establish “zero discharge” effluent limitations and standards for discharges of pollutants in fly ash transport water, based on the use of dry fly ash handling technologies. The dry handling technologies for fly ash are described in Section 7. Although surface impoundments can be effective at removing particulate forms of certain metals and other pollutants, they are not designed for, nor are they effective at, removing other pollutants of concern such as dissolved metals and nutrients. The concentrations of pollutants that remain in the ash impoundment effluent following gravity settling, in combination with the large volumes of fly ash transport water discharged to surface waters (2.4 MGD on average per discharging plant), results in a large mass loading of pollutants of concern being discharged from surface impoundments. Furthermore, as described in Section 8.1.2.1, surface impoundments can be susceptible to seasonal turnover that degrades pollutant removal efficacy, and co-managing FGD and ash wastes in the same impoundments can lead to increased pollutant discharges.

Dry handling technologies are the technology basis for the current fly ash NSPS/PSNS requirements, which were promulgated in 1982. All generating units built since then have been subject to a “zero discharge” standard. Some existing units have also converted to dry handling technologies. Due to the NSPS discharge standard or economic or operational factors, approximately 66 percent of coal- and petroleum coke-fired generating units that produce fly ash currently operate dry fly ash transport systems, while another 15 percent operate both wet and dry fly ash transport systems. The remaining 19 percent operate only wet fly ash transport systems. In cases where a unit has both wet and dry handling operations, the wet handling system is typically used as a backup to the dry system. Effluent limitations and standards based on dry ash handling would completely eliminate the discharge of pollutants in fly ash transport water.

EPA considered basing one or more regulatory options for fly ash transport water on chemical precipitation treatment technology, with numeric effluent limits for discharges of the wastestream to surface waters. EPA has not identified any facilities using this treatment technology to treat fly ash transport water, although EPA has reviewed two literature sources that describe laboratory- or pilot-scale tests using the technology. Upon reviewing the discharge flow rates for fly ash transport water, however, EPA determined that the costs associated with treatment using chemical precipitation were higher than the cost of the dry handling technology upon which Options 3a, 3b, 3, 4a, 4, and 5 are based, despite being less effective at removing pollutants. Because the costs for chemical precipitation treatment are higher than the cost for converting to dry handling technologies, and chemical precipitation removes fewer pollutants, EPA did not include chemical precipitation treatment as part of the regulatory options for fly ash transport water in this proposed rule [ERG, 2013b].

EPA is proposing that the limitations for existing sources based on Options 3a, 3b, 3, 4a, 4, or 5 would apply to discharges of fly ash transport water generated after the date established by the permitting authority that is as soon as possible within the next permit cycle after July 1, 2017. For indirect dischargers, EPA is proposing that PSES for fly ash would apply to the fly ash transport water generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Fly ash transport water generated by existing direct dischargers prior to that date (i.e., "legacy" wastewater) would remain subject to the existing BPT effluent limits. EPA considered subjecting legacy fly ash transport water (i.e., the fly ash transport water generated prior to the date established by the permitting authority, as described above) to the proposed BAT zero discharge requirement. As explained above, currently fly ash transport wastewater and the associated pollutants are sent to surface impoundments for treatment prior to discharge. The technology basis identified for the proposed zero discharge requirement eliminates the generation of the fly ash wastewater but does not eliminate fly ash transport wastewater that has already been transferred to a surface impoundment. Furthermore, the technologies identified as the basis for fly ash transport water discharge requirements have not been demonstrated for the legacy fly ash transport wastewater that has already been generated. As such, EPA is not proposing BAT or PSES requirements for discharges of legacy fly ash transport water generated prior to the date established by the permitting authority or control authority. As proposed, discharges of legacy fly ash transport water by existing direct dischargers would remain subject to the existing BPT effluent limits; however, EPA is also considering whether to set the BAT effluent limitations for legacy fly ash transport water equal to the existing BPT effluent limits. See Section 14.1.3 for additional information.

8.1.2.3 Bottom Ash Transport Water

Under Options 1, 3a, 2, 3b, 3, and 4a (for units less than or equal to 400 MW), effluent limitations and standards for bottom ash transport water would be set equal to the current BPT effluent limitations, based on the technology of gravity settling in surface impoundments to remove suspended solids. The 1982 effluent guidelines for existing sources include BPT effluent limits for the allowable levels of TSS and oil and grease in discharges of bottom ash transport water. The BPT effluent limits are based on the performance of surface impoundments, which when well-designed and well-operated can effectively remove suspended solids, including pollutants such as particulate forms of certain metals when associated with the suspended solids.

Although surface impoundments can be effective at removing particulate forms of metals and other pollutants, they are not designed for nor are they effective at removing other pollutants of concern such as dissolved metals and nutrients. The concentrations of pollutants that remain in the wastestream at the ash impoundment effluent, in combination with the large volumes of bottom ash transport water discharged to surface waters, results in a large mass loading of pollutants of concern being discharged from surface impoundments. Effluent limitations and standards based on the technologies used as the basis for Options 4a (for units more than 400 MW), 4, and 5 would completely eliminate the discharge of pollutants in bottom ash transport water.

Under Options 4a (for units more than 400 MW), 4, and 5, EPA would establish "zero discharge" effluent limitations and standards for discharges of pollutants in bottom ash transport water, based on either using bottom ash handling technologies that do not require transport water or managing a wet-sluicing bottom ash handling system so that it does not discharge bottom ash transport water or pollutants associated with the bottom ash transport water. These technologies for handling bottom ash are described above in Section 7. About 80 percent of coal- and petroleum coke-fired units generating bottom ash operate wet bottom ash transport systems, while approximately 20 percent operate systems that eliminate the use of transport water. Most, but not all, of the wet bottom ash transport systems discharge to surface waters. In cases where a plant has both wet and dry handling operations, the wet handling system is typically used as a backup to the dry system. In the case of bottom ash handling systems, the term "dry" is typically used to refer to a process that does not use water as the transport medium to sluice the bottom ash to a CCR impoundment. In some cases, a "dry" bottom ash system may be entirely dry and avoid all use of water. Many dry bottom ash systems, however, include a water bath at the bottom of a boiler in which the bottom ash is dropped and cooled, and then the bottom ash is mechanically dragged out of the boiler along a conveyor belt and deposited in a pile adjacent to the building housing the boiler. The bottom ash conveyed out of the water bath will be damp because the ash particles retain some moisture from the water bath and small volumes of water will typically drain from the standing bottom ash pile. The water draining from the pile is usually collected in a sump and either returned to the water bath below the boiler or managed as low volume waste. Such mechanical drag systems are considered as one available technology that may be used to achieve proposed limitations and standards under Options 4a (for units >400 MW), 4, and 5. Other technologies serving as the basis for limitations and standards proposed under Options 4a (for units >400 MW), 4, and 5 are completely dry bottom ash systems, remote mechanical drag systems, and impoundment-based systems that are managed to eliminate the discharge of all bottom ash transport water and the associated pollutants.

In developing the technologies that serve as the basis for the regulatory options with respect to bottom ash transport water, EPA considered basing one or more options on chemical precipitation treatment technology, with numeric effluent limitations or standards for discharges of the wastestream to surface waters. Upon reviewing the discharge flow rates for bottom ash transport water, however, EPA determined that the costs associated with treatment were comparable to the cost of the technologies upon which Options 4a (for units more than 400 MW), 4, and 5 are based, despite being less effective at removing pollutants. Because the costs for chemical precipitation treatment were found to be higher than the cost for converting to dry handling or closed loop technologies, and the treatment technology removes fewer pollutants, EPA did not include chemical precipitation treatment as part of the regulatory options for bottom ash in this proposed rule [ERG, 2013b].

EPA is proposing that certain BAT limitations for existing sources under Options 4a (for units more than 400 MW), 4, or 5 would apply to discharges of bottom ash transport water generated after the date established by the permitting authority or control authority that is as soon as possible within the next permit cycle after July 1, 2017. For indirect dischargers, EPA is proposing that PSES for bottom ash transport water would apply to bottom ash transport water generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Bottom ash transport water generated by existing direct dischargers prior to that date (i.e., "legacy" wastewater) would remain subject to the existing BPT effluent limits. EPA considered subjecting legacy bottom ash transport water (i.e., the bottom ash transport water generated prior to the date established by the permitting authority or control authority to the BAT and PSES zero discharge requirement considered under Options 4a (for units more than 400 MW), 4, and 5. As explained above, currently, bottom ash transport wastewater and the associated pollutants are sent to surface impoundments for treatment prior to discharge. The technology bases identified above for Options 4a (for units more than 400 MW), 4, and 5 eliminate the generation of the bottom ash wastewater but do not eliminate bottom ash transport wastewater that has already been transferred to a surface impoundment. The technologies identified as the basis for bottom ash transport water discharge requirements under Options 4a (for units more than 400 MW), 4, and 5 have not been demonstrated for the legacy bottom ash transport wastewater that has already been generated and do not represent BAT/PSES with respect to legacy bottom ash wastewater. As such, under Options 4a (for units more than 400 MW), 4, and 5 EPA would not establish BAT or PSES requirements for discharges of legacy bottom ash transport water generated prior to the date established by the permitting authority. As proposed, discharges of legacy bottom ash transport water by existing direct dischargers would remain subject to the existing BPT effluent limits; however, EPA is also considering whether to set the BAT effluent limitations for legacy bottom ash transport water equal to the existing BPT effluent limits. See Section 14.1.3 for additional information.

8.1.2.4 Leachate from Surface Impoundments and Landfills Containing Combustion Residuals

Under Options 1, 3a, 2, 3b, 3, and 4a, effluent limitations and standards for leachate from surface impoundments and landfills containing combustion residuals would be set equal to the current BPT effluent limitations, based on the technology of gravity settling in surface impoundments to remove suspended solids. Leachate is currently included under the definition of low volume wastes, which are regulated by effluent limits for TSS and oil and grease based on surface impoundments designed to remove suspended solids. EPA is proposing that under Options 1, 3a, 2, 3b, 3, and 4a, the rule would remove leachate from the definition of low volume wastes at 40 CFR 423.11(b) and would set BAT effluent limits for leachate equal to BPT limits for TSS and oil and grease (i.e., the current effluent limits for low volume wastes).

The technology basis for effluent limitations and standards for leachate under Options 4 and 5 is chemical precipitation/coprecipitation. This same technology is the basis for BAT Option 1 for FGD wastewater. Properly designed and operated surface impoundments can effectively remove suspended solids, including pollutants such as particulate forms of certain metals when associated with the suspended solids. However, since surface impoundments are not designed for, nor are they effective at, removing other pollutants of concern such as dissolved metals, EPA used chemical precipitation/coprecipitation as the technology basis for combustion residual leachate for Options 4 and 5. Physical/chemical treatment systems are capable of achieving low effluent concentrations of various metals and are effective at removing many of the pollutants of concern present in leachate discharges to surface waters. The pollutants of concern in leachate are the same pollutants that are present in, and in many cases are also pollutants of concern for, FGD wastewater, fly ash transport wastewater, bottom ash transport water, and other combustion residuals. This is to be expected since the leachate itself comes from landfills and surface impoundments containing the combustion residuals and those wastes are the source for the pollutants entrained in the leachate. Given the similarities present among the different types of wastewaters associated with combustion residuals, combustion residual leachate will be similarly amenable to chemical precipitation treatment. The treatability of pollutants such as arsenic and mercury using chemical precipitation technology is also demonstrated by technical information compiled for ELGs promulgated for other industry sectors. See, e.g., the TDDs supporting the ELGs for the Landfills Point Source Category (EPA-821-R-99-019) and the ELGs for the Metal Products and Machinery Point Source Category (EPA-821-B-03-001). However, as is the case when treating FGD wastewater, this technology is not effective at removing selenium, boron and certain other parameters that contribute to total dissolved solids (e.g., magnesium, sodium).

EPA also considered developing a regulatory option that, for leachate, would be based on the technology of chemical precipitation/coprecipitation used in conjunction with anoxic/anaerobic biological treatment. This is the same technology used as the basis for effluent limitations and standards for FGD wastewater under Options 2, 3b (for units at facilities with a total wet-scrubbed capacity of 2,000 MW or more), 3, 4a, and 4. EPA has reviewed this technology as a potential basis for effluent limitations and standards for leachate. The microorganisms used in the bioreactors for the biological treatment technology for FGD wastewater are resilient and have shown that they operate effectively under varying conditions that occur in FGD system and the FGD wastewater treatment system. However, leachate flows can be more variable than FGD wastewater and, more importantly, may be too intermittent to facilitate reliable and consistent biological treatment. Such variations are easily accommodated in a chemical precipitation treatment system, but may be difficult to manage in a biological treatment system reliant on healthy and sustainable populations of microorganisms.

If EPA did finalize BAT effluent limits developed under Options 4 or 5 (although these options are not the preferred options included in the proposed rule), EPA's intent is that these limits would apply to discharges of leachate generated after the date established by the permitting authority that is as soon as possible within the next permit cycle after July 1, 2017. For indirect dischargers, PSES for leachate would apply to leachate generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Leachate generated by existing direct dischargers prior to that date (i.e., "legacy" leachate wastewater) would remain subject to the existing BPT effluent limits. EPA considered subjecting legacy leachate wastewater to the proposed BAT and PSES limitations and standards. However, although some plants use relatively small surface impoundments to treat leachate and these impoundments would contain relatively small volumes of legacy leachate wastewater, other plants send leachate to relatively large surface impoundments that also contain other plant wastewaters, such as fly ash or bottom ash transport water, cooling water, and/or other low volume wastes. EPA does not have the data to demonstrate that the technologies identified above represent BAT for legacy combustion residual leachate. As such, EPA would not expect to finalize BAT requirements associated with discharges of legacy combustion residual leachate (i.e., the leachate generated prior to the date established by the permitting authority or control authority). As proposed, discharges of legacy combustion residual leachate by existing direct dischargers would remain subject to the existing BPT effluent limits; however, EPA is also considering whether to set the BAT effluent limitations for legacy combustion residual leachate that has not been mixed with non-legacy wastes equal to the existing BPT effluent limits. See Section 14.1.3 for additional information.

8.1.2.5 FGMC Wastewater

Under Options 1 and 2, effluent limitations and standards for FGMC wastewater would be set equal to the current BPT effluent limitations, based on the technology of gravity settling in surface impoundments to remove suspended solids. Like leachate, FGMC wastewater is currently included under the definition of low volume wastes, with effluent limits for TSS and oil and grease based on surface impoundments designed to remove suspended solids. EPA is proposing that under all options, FGMC wastewater would be removed from the definition of low volume wastes at 40 CFR 423.11(b). Under Options 1 and 2, BAT effluent limits for FGMC wastewater would be set equal to BPT limits for TSS and oil and grease (i.e., the current effluent limits for low volume wastes).

As discussed in Section 4.3.4, some plants inject dry sorbents (e.g., activated carbon) into the flue gas stream to reduce mercury emissions from the flue gas. Mercury adsorbs to the sorbent particles, and these mercury-enriched sorbents are then removed from the flue gas using a fabric filter or ESP. The sorbent can be injected upstream of the primary particulate collector, in which case the mercury-enriched sorbent is collected with the majority of the fly ash. Alternatively, the sorbent can be injected downstream of the primary particulate collector and collected with a much smaller amount of fly ash (i.e., the fly ash that passed through the primary collector) in a smaller, dedicated secondary particulate collector such as a fabric filter. In either case, the plant collects the mercury-enriched sorbents along with fly ash. Because of this, the BAT technology basis for FGMC wastewater in this proposal is identical to the BAT technology basis for fly ash.

Under Options 3a, 3b, 3, 4a, 4, and 5, EPA would establish "zero discharge" effluent limitations and standards for discharges of pollutants in FGMC wastewater based on using dry handling technologies to store and dispose of fly ash without utilizing transport water. The dry handling technologies that would be used for FGMC wastes are identical to the dry fly ash handling technologies described in Section 7.2. Although surface impoundments can effectively remove particulate forms of metals and other pollutants, they are not designed for nor are they effective at removing other pollutants of concern such as dissolved metals and nutrients. Effluent limits based on dry handling would completely eliminate the discharge of pollutants in FGMC wastewater.

EPA is also aware of some plants that add oxidizers to the coal prior to burning the coal in the boiler. This chemical addition oxidizes the mercury present in the flue gas, which allows the plant to remove mercury more readily from the flue gas in the wet FGD system. EPA did not evaluate separate treatment technologies for the use of oxidizers to control flue gas mercury emissions because using oxidizers does not generate a separate FGMC wastewater.

To the extent that a power plant generates FGMC wastewater before any BAT zero discharge limitation were to apply, the proposed BAT limitations under Options 3a, 3b, 3, 4a, 4, and 5 would apply to discharges of FGMC wastewater generated after the date established by the permitting authority that is as soon as possible within the next permit cycle after July 1, 2017. For indirect dischargers, EPA is proposing that PSES for FGMC wastewater would apply to FGMC wastewater generated after a date determined by the control authority that is as soon as possible beginning July 1, 2017. As proposed, legacy FGMC wastewater generated by existing direct dischargers prior to that date would remain subject to the existing BPT effluent limits; however, EPA is also considering whether to set the BAT effluent limitations for legacy FGMC wastewater equal to the existing BPT effluent limits. EPA considered subjecting legacy FGMC wastewater to the proposed BAT/PSES zero discharge requirements. As described in Section 7.5, although most FGMC wastes are managed using dry handling systems, EPA has identified six plants that manage their FGMC waste with systems that use water to transport the waste to surface impoundments. The technology basis identified for the proposed zero discharge requirement eliminates the generation of the FGMC wastewater by implementing certain process changes that do not use water to transport the FGMC waste; however, it does not eliminate the already-generated FGMC wastewater that has already been transferred to and stored in a surface impoundment. The technologies that underlie Regulatory Options 3a, 3b, 3, 4a, 4, and 5 do not represent BAT or PSES for the control of pollutants from legacy FGMC wastewater and would not allow FGMC wastewater that has already been generated to comply with a zero discharge requirement. As such, EPA is not proposing BAT or PSES requirements associated with discharges of legacy FGMC wastewater generated prior to the date established by the permitting authority or control authority. However, EPA is considering whether to set the BAT effluent limitations for legacy FGMC wastewater equal to the existing BPT effluent limits. See Section 14.1.3 for additional information.

8.1.2.6 Gasification Wastewater

The technology basis for the effluent limitations for all eight regulatory options for gasification wastewater is vapor-compression evaporation. Two operating IGCC plants in the U.S. currently use this technology, and a third IGCC plant that is scheduled to begin commercial operation soon will also use it to treat gasification wastewater. Like leachate and FGMC wastewater, gasification wastewater is currently included under the definition of low volume wastes, with effluent limits for TSS and oil and grease based on surface impoundments designed to remove suspended solids. EPA considered using surface impoundments as the technology basis for one or more of the regulatory options for gasification wastewater. However, surface impoundments are not effective at removing the pollutants of concern present in gasification wastewater. In addition, one of the currently operating IGCC plants formerly used a surface impoundment to treat its gasification wastewater and the impoundment effluent repeatedly exceeded NPDES permit limits established to protect water quality. Because of the demonstrated inability of surface impoundments to remove the pollutants of concern and the current industry practice of operating vapor-compression evaporation to treat the gasification wastewater at all U.S. IGCC plants, EPA determined that surface impoundments do not represent BAT level of control.

In addition to the vapor-compression evaporation technology that is the basis for all BAT and BADCT/NSPS options for gasification wastewater, EPA considered also including cyanide treatment as part of the technology basis for one or more options. EPA notes that the Edwardsport IGCC plant that is scheduled to soon begin commercial operation includes cyanide destruction as one step in the treatment process for gasification wastewater. However, EPA currently does not have sufficient gasification wastewater data with which to calculate effluent limits based on the performance of cyanide treatment as part of a BAT/BADCT (NSPS) regulatory option. A possible approach to resolve this would be to transfer effluent limits for cyanide from an ELG for another industry sector. Alternatively, EPA may obtain effluent data from the gasification wastewater treatment system for the Edwardsport IGCC unit once it begins commercial operation and use these data to calculate effluent limitations for cyanide.

8.1.2.7 Nonchemical Metal Cleaning Wastes

The technology basis for the effluent limitations for all eight regulatory options for nonchemical metal cleaning wastes is chemical precipitation. Separation processes in the physical/chemical treatment, along with chemical addition when needed to facilitate coagulation and settling of suspended solids, would effectively remove TSS and oil and grease to effluent concentrations below the limitations included in the proposed rule. In addition, treatment chemicals added to adjust pH to precipitate dissolved metals or to facilitate flocculation/coagulation are effective at removing copper and iron to effluent concentrations below the proposed limitations, in addition to reducing the concentrations of other pollutants present in nonchemical metal cleaning wastes.

The current ELG relies on three key terms specific to metal cleaning waste: “metal cleaning waste,” “chemical metal cleaning waste,” and “nonchemical metal cleaning waste.” The regulation includes a definition of the broadest term, “metal cleaning waste,” as “any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.” 40 CFR 423.11(d). Thus, this definition includes *any* wastewater generated from *either the chemical or nonchemical cleaning* of metal process equipment. In addition, the regulation also defines “chemical metal cleaning waste” as “any wastewater resulting from cleaning of any metal process equipment with chemical compounds, including, but not limited to, boiler tube cleaning.” See 40 CFR 423.11(c). The regulation also includes, but does not expressly define the term “nonchemical metal cleaning waste” when it states that it has “reserved” the development of BAT ELGs for such wastes. See 40 CFR 423.13(f). Although the regulation provides no definition of “nonchemical metal cleaning waste,” it is clear from the definitions of *metal cleaning waste* and *chemical metal cleaning waste* that *nonchemical metal* *cleaning waste* is any wastewater resulting from the cleaning of metal process equipment without chemical cleaning compounds.

The current ELGs include BPT effluent limits for the allowable levels of TSS, oil and grease, copper and iron in discharges of metal cleaning waste, which includes both chemical and nonchemical metal cleaning wastes. Although the current BPT effluent limits apply to nonchemical metal cleaning wastes, EPA has found that some discharges of nonchemical metal cleaning waste are authorized pursuant to permits incorporating limitations based on BPT requirements for low volume wastes and, therefore, do not have iron and copper limits. The information EPA has collected to date indicates many facilities are not discharging nonchemical metal cleaning wastewater or have copper and iron limits (see Section 7.7 for more information).

The current ELGs do not include BAT/NSPS requirements for the broadly defined category of metal cleaning wastes; however, they do include BAT/NSPS for chemical metal cleaning waste. EPA has not promulgated BAT/NSPS for nonchemical metal cleaning waste. Similarly, although the current ELGs do not include PSES/PSNS for metal cleaning waste, they do include PSES/PSNS for chemical metal cleaning waste. EPA has not promulgated PSES/PSNS for nonchemical metal cleaning waste. An overview of the ELGs and existing limitations for metal cleaning waste, including chemical and nonchemical metal cleaning waste, is included in Table 1-1.

As described above, EPA found that some discharges of nonchemical metal cleaning waste are authorized pursuant to permits incorporating limitations based on BPT requirements for low volume wastes and, therefore, do not have iron and copper limits. Because the potential costs for dischargers to comply with iron and copper limits is not known, EPA is proposing to provide an exemption from new copper and iron limitations or standards for existing discharges of nonchemical metal cleaning wastes from generating units that are currently authorized without iron and copper limits. For these discharges, BAT limitations for nonchemical metal cleaning waste would be set equal to BPT limitations for low volume waste, and the regulations would not specify PSES.

EPA is also considering setting BAT for nonchemical metal cleaning waste equal to the metal cleaning waste BPT for all nonchemical metal cleaning wastes (i.e., no exemption for discharges of nonchemical metal cleaning wastes currently authorized without iron and copper limits) and, for PSES, to establish copper standards for all discharges of nonchemical cleaning wastes. As part of this approach, EPA is evaluating whether some plants would incur costs to comply with the current BPT standards

8.1.2.8 Anti-Circumvention Provision

EPA is proposing to add provisions to the regulations that would prevent facilities from circumventing the effluent limitations guidelines and standards. The proposed provisions would do three things, as described below.

First, the anti-circumvention provision would require that compliance with the new effluent limits applicable to a particular wastestream (e.g., FGD, gasification wastewater, leachate) be demonstrated prior to use of the wastewater in another plant process that results in surface water discharge or mixing the treated wastestream with other wastestreams. Under 40 CFR 122.45(h), in situations where an NPDES permit effluent limitations or standards imposed at the point of discharge are impractical or infeasible, effluent limitations or standards may be imposed on internal wastestreams before mixing with other wastestreams or cooling water streams. Limitations on internal wastestreams may be necessary, such as in situations where the wastes at the point of discharge are so diluted as to make monitoring impracticable, or the interferences among pollutants would make detection or analysis impracticable. Many power plants combine FGD wastewater and other power plant wastewaters with ash transport water and/or cooling water prior to discharge, which can dilute the wastewaters by several orders of magnitude prior to the final outfall. In addition, surface impoundments typically contain a variety of wastes (e.g., ash transport water, coal pile runoff, landfill/impoundment leachate) that when mixed with the FGD wastewater or gasification wastewater may make the analysis to measure compliance with technology-based effluent limits impracticable. Because of the high degree of dilution and the number of wastestream sources containing similar pollutants, effluent limits and monitoring requirements for certain internal wastestreams (e.g., FGD wastewater, combustion residual leachate, gasification wastewater) are necessary to ensure appropriate control of the pollutants present in the wastewater.

Second, the anti-circumvention provision would establish requirements intended to prevent steam electric power plants from circumventing the effluent limits and standards by moving effluent produced by a process operation for which there is a zero discharge effluent limit/standard to another process operation for discharge under less stringent requirements than intended by the steam electric ELGs. For example, several options (including Option 3a) considered in this rulemaking would establish a zero discharge requirement for pollutants in fly ash transport water and FGMC wastewater. If this option were selected for the final rule, the anti-circumvention provisions would allow power plants to recycle/reuse these wastestreams in ash transport processes or other plant processes, but only to the extent that the plants do not discharge any pollutants associated with flue gas mercury controls or transporting fly ash. The presence of a zero discharge wastestream in a process that ultimately discharges to surface water (e.g., use of fly ash transport water as FGD absorber make-up water in a scrubber that discharges FGD wastewater) would not be in compliance with the effluent limit.

Last, the anti-circumvention provisions would expressly require permittees to use analytical EPA-approved methods that are sufficiently sensitive to provide reliable quantified results at levels necessary to demonstrate compliance with the effluent limits proposed by this rulemaking when such methods are available. EPA's detailed study and the field sampling for this rulemaking demonstrate that the use of sufficiently sensitive analytical methods is critically important to detecting, identifying, and measuring the concentrations of pollutants present in power plant wastewaters. Where EPA has approved more than one analytical method for a pollutant, the Agency expects that permittees would select methods that are able to quantify the presence of pollutants in a given discharge at concentrations that are low enough to determine compliance with effluent limits, when such methods are available. Facilities should not use a less sensitive or less appropriate method, thus masking the presence of a pollutant in the discharge, when an EPA-approved method is available that can quantify the pollutant concentration at the lower levels needed for demonstrating compliance. For purposes of the proposed anti-circumvention provision, a method is "sufficiently sensitive" when the sample-specific quantitation level for the wastewater being analyzed is at or below the level of the effluent limitation.[45] Allowing plants to use insufficiently sensitive analytical methods for compliance monitoring purposes when EPA-approved sufficiently sensitive methods are available could result in an undetected exceedance of the effluent limits.

8.1.2.9 BMPs for CCR Surface Impoundments

EPA is considering establishing BMPs for plant operators to conduct periodic inspections of active and inactive surface impoundments and to take corrective actions where warranted. This requirement would apply to direct dischargers. For new sources, EPA would be relying on CWA section 306, which authorizes the promulgation of standards of performance for new sources. For existing sources, EPA would be relying on CWA section 304(e), which authorizes BMPs supplemental to ELGs for toxic or hazardous pollutants to control plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage which the Administrator determines are associated with or ancillary to the industrial process and may contribute significant amounts of pollutants to the nation’s waters. And CWA section 402(a) (2) authorizes the imposition of conditions, which would include BMPs and monitoring requirements, necessary to ensure compliance with all other applicable requirements. EPA’s regulation at 40 CFR 122.44(k) implements these authorities. Specifically, 40 CFR 122.44(k) allow for NPDES permits to require the use of BMPs to control and abate the discharge of toxic pollutants. Existing regulations at 40 CFR 122.41(e) further require that NPDES permittees properly operate and maintain all facilities and systems of treatment and control used to achieve compliance with their permits. Using CWA authority, EPA could establish the BMPs as part of the ELGs (BAT and NSPS) codified at 40 CFR part 423, and thus these BMPs would be implemented through NPDES permits. Structural integrity requirements that seek to reduce the potential for catastrophic releases from surface impoundments could, alternatively, be established using RCRA authority. The BMPs under consideration in this rulemaking are similar to the structural integrity inspection and corrective active requirements proposed in the CCR rulemaking, but do not include closure requirements that were proposed as part of the CCR rulemaking.

The Agency believes that the BMP requirements being considered by the Agency in this rulemaking and in the CCR rulemaking are critical to ensure that the owners and operators of surface impoundments become aware of any problems that may arise with the structural stability of the surface impoundment before they occur and, thus, prevent catastrophic releases, such as those that occurred at Martins Creek, Pennsylvania and TVA’s Kingston, Tennessee facility.

The BMPs being considered by EPA in this rulemaking would require, first, that inspections be conducted every seven days by a person qualified to recognize specific signs of structural instability and other hazardous conditions by visual observation and, if applicable, to monitor instrumentation such as piezometers. If a potentially hazardous condition develops, the owner or operator shall immediately take action to eliminate the potentially hazardous condition; notify the Regional Administrator or the authorized State Director; and notify and prepare to evacuate, if necessary, all personnel from the property that may be affected by the potentially hazardous condition(s). Additionally, the owner or operator must notify state and local

[45] For the purposes of this rulemaking, EPA is considering the following terms related to analytical method sensitivity to be synonymous: “quantitation limit,” “reporting limit,” “level of quantitation,” and “minimum level.”

emergency response personnel if conditions warrant so that people living in the area down gradient from the surface impoundment can evacuate. Reports of inspections are to be maintained in the facility operating record.

Second, to address the integrity of surface impoundments, EPA would establish BMPs for CCR surface impoundments similar to those promulgated for coal slurry impoundments regulated by the Mine Safety and Health Administration (MSHA) at 30 CFR 77.216. Although the MSHA regulations are applicable to coal slurry impoundments at coal mines and not to the impoundments containing CCR at power plants, there are sufficient similarities between coal slurry and CCR impoundments for the MSHA regulations to be used as a model for the BMP requirements being considered for the ELG rule. Facilities using CCR impoundments would need to (1) submit to EPA or the authorized state plans for the design, construction, and maintenance of existing impoundments, (2) submit to EPA or the authorized state plans for closure, (3) conduct periodic inspections by trained personnel who are knowledgeable in impoundment design and safety, and (4) provide an annual certification by an independent registered professional engineer that all construction, operation, and maintenance of impoundments is in accordance with the approved plan. When problematic stability and safety issues are identified, owners and operators would be required to address these issues in a timely manner.

In developing these possible structural integrity BMP requirements, EPA sought advice from the federal agencies charged with managing the safety of dams in the United States. Many agencies in the federal government are charged with dam safety, including the U.S. Department of Agriculture (USDA), the Department of Defense (DOD), the Department of Energy (DOE), the Nuclear Regulatory Commission (NRC), the Department of Interior (DOI), and the Department of Labor (DOL), MSHA. EPA looked particularly to MSHA, whose charge and jurisdiction appeared to EPA to be the most similar to the Agency's in this context. MSHA's jurisdiction extends to all dams used as part of an active mining operation and their regulations cover "water, sediment or slurry impoundments" so they include dams for waste disposal, freshwater supply, water treatment, and sediment control. In fact, MSHA's current impoundment regulations were created as a result of the dam failure at Buffalo Creek, West Virginia on February 26, 1972. (This failure released 138 million gallons of stormwater run-off and fine coal refuse, and resulted in 125 persons killed, another 1,000 injured, over 500 homes completely destroyed, and nearly 1,000 others damaged.)

MSHA has nearly 40 years of experience writing regulations and inspecting dams associated with coal mining. MSHA's regulations are comprehensive and directly applicable to the dams used in surface impoundments at coal-fired utilities to manage CCRs. EPA believes that, based on the record compiled by MSHA for its rulemaking, and on MSHA's 40 years of experience implementing these regulations, the requirements being considered in this rulemaking would substantially reduce the potential for catastrophic release of CCRs from surface impoundments, as occurred at TVA's facility in Kingston, Tennessee, and would generally meet

RCRA's objective to ensure the protection of humans and the environment.[46] Thus, EPA is considering establishing BMPs that would be modeled on MSHA regulations in 30 CFR Part 77.

MSHA's regulations for coal slurry impoundments apply to those impoundments at coal mines, which impound water, sediment or slurry to an elevation of more than five feet and have a storage volume of 20 acre-feet or more and those coal slurry impoundments that impound water, sediment, or slurry to an elevation of 20 feet or more. The BMPs being considered for the ELG rule would apply to all CCR impoundments at steam electric power generating facilities, regardless of height and storage volume. EPA is also considering variations on BMPs for the ELGs, including, but not limited to, different inspection frequencies or limitations on the applicability of BMPs that more closely mirror the applicability of the MSHA regulations.

8.1.2.10 Voluntary Incentive Program for Power Plants that Close CCR Impoundments or Eliminate All Process Wastewater Dischargers (Except Cooling Water

EPA is considering establishing, as part of the BAT for existing sources, a voluntary incentive program that provides more time for plants to implement the proposed BAT requirements if they adopt additional process changes and controls that provide significant environmental protections beyond those achieved by the preferred options for this proposed rule. The development of advanced process changes and controls is a critical step toward the Clean Water Act's ultimate goal of eliminating the discharge of pollutants into the Nation's waters. See CWA Section 101(a)(1). Section 301(b)(1)(C) demands that BAT result in "reasonable further progress toward the national goal of eliminating the discharge of pollutants." EPA intends that, for any BAT option that is ultimately selected as part of any final ELG rule, such option would represent "reasonable further progress," while the voluntary incentives program is designed to continue progress toward achieving the national goal of the Act. In addition, Section 104(a)(1) of the Act gives the Administrator authority to establish national programs for the prevention, reduction, and elimination of pollution, and it provides that such programs shall promote the acceleration of research, experiments, and demonstrations relating to the prevention, reduction, and elimination of pollution. The voluntary incentives program being considered for the proposed rule would effectively accelerate the research into and use of controls and processes intended to prevent, reduce, and eliminate pollution because it would increase the number of plants choosing to close and cap CCR surface impoundments and eliminate discharges of all process wastewater (except cooling water) to surface waters.

This voluntary program would establish two levels, or "tiers," of advanced technology performance requirements which would be incorporated into the NPDES permits for the facilities that participate in the program. Under Tier 1, power plants would be granted two additional years (beyond the time described below in Section 8.2) if they also dewater, close and cap all CCR surface impoundments (except for those impoundments containing only combustion residual

[46] On December 22, 2008, the retention wall of a coal ash impoundment at Tennessee Valley Authority's Kingston Plant collapsed, which resulted in a massive release of CCRs directly into the Emory River and its tributaries. The Emory River joins to the Clinch River and then converges with the Tennessee River, a major drinking water source for populations downstream. This failure released over a billion gallons of fly ash and bottom ash, which impacted over 100 properties, destroyed three homes, and ruptured a gas line resulting in the evacuation of 22 residents.

leachate) at the facility, including those surface impoundments located on non-adjoining property that receive CCRs from the facility. A power plant participating in the Tier 1 program could continue to operate surface impoundments for which combustion residual leachate is the only type of CCR solids or wastewater contained in the impoundment. In general, power plants accepted in the Tier 1 incentives program would first convert ash handling operations to dry handling or closed-loop tank-based systems and FGD wastewater treatment operations to tank-based systems, as described above in Section 7. This first step would eliminate new contributions of CCRs (solids and wastewater) to the surface impoundments. The plants would then dewater the impoundments by draining or pumping the wastewater from the impoundments, in compliance with the ELGs and other requirements established in their NPDES permits. Upon completing the dewatering operations, plants would then stabilize the contents and close and cap the impoundments consistent with state requirements and any other additional requirements that may be established by EPA as part of the Tier 1 incentives program or other applicable requirements.

Under Tier 2, power plants would be granted five additional years (beyond the time described below in Section 8.2) if they eliminate the discharge of all process wastewater to surface waters, with the exception of cooling water discharges. The Tier 2 incentives would not be available to power plants that eliminate direct discharge to surface water by sending the wastewater to a POTW. A plant accepted into the Tier 2 incentives program would ultimately need to manage its processes and wastewater in a manner that implements a coordinated approach toward wastewater minimization, treatment and reuse. To achieve Tier 2 status, these plants would eliminate all process wastewater discharges (except cooling water) by reducing the amount of wastewater generated and preferentially using recycled wastewater to meet water supply demands. To accomplish this, Tier 2 plants would conduct engineering assessments of the processes that generate wastewater and identify opportunities to eliminate or reduce the amount of wastewater they generate. These plants would also assess the processes that use water and determine how they could use recycled wastewater in those processes, as well as the degree of treatment that may be needed to enable such reuse. Based on responses to the industry survey, EPA has identified a number of steam electric power plants that currently discharge no process wastewater. In addition, two of the plants that EPA visited in Italy previously discharged process wastewater, but have implemented wastewater treatment and process changes, including wastewater recycle, that now allow them to operate without discharging any process wastewater except for their cooling water.

The primary objective of this program is to encourage individual power plants to install advanced pollution prevention technologies or make process changes that would further reduce releases of toxic pollutants to the environment beyond the limits that would be set by the proposed rule. The voluntary incentive program being considered is designed to promote improvements that, in concert with other environmental practices, make significant progress toward achieving EPA's vision of the "power plant of the future" – one which will have a minimum impact on the environment. This program would give power plants a platform to advance the research and development of technologies and processes that promote water conservation and water recycling and provide greater environmental protection. EPA has conducted site visits at power plants that have implemented processes that eliminate the use of water or recycle process wastewater to a substantial degree. Furthermore, as noted above, EPA observed operations at power plants that implemented process modifications and treatment technologies that eliminated all discharges of process wastewater with the exception of their cooling water. Implementing such practices at other power plants would dramatically reduce discharges of toxic and other pollutants. These practices would also substantially reduce the amount of water consumed or used by the plant, which could be an important consideration for addressing water availability and other concerns. In exchange for providing additional time for power plants to comply with the proposed BAT limitations, the program would lead to superior effluent quality and greater environmental protection.

Participation in the program would be voluntary and it would be available only to existing power plants that discharge directly to surface waters. Power plants would have until July 1, 2017 (approximately 3 years after promulgation of the final ELGs) to commit to the program and submit a plan for achieving the Tier 1 or Tier 2 requirements. Once a power plant enrolls in the program, the NPDES permitting authority would develop specific discharge limits and key milestones consistent with that tier.

Power plants enrolled in the program would ultimately be agreeing to adopt NPDES permit limits that are more stringent than those that would be required by the proposed and final BAT in exchange for additional time to comply with their new effluent limitations. These power plants and their corporate owners would also receive public recognition for their commitment to increased environmental protection.

EPA considered including features of the Tier 1 and Tier 2 incentives as part of the options for the proposed rule. However, although EPA has observed these practices in operation and they are available for at least a portion of the industry, the degree of complexity will vary from plant to plant and EPA does not have the site-specific information that could be used to sufficiently assess how that complexity may affect the engineering challenges and costs that plants would encounter.

8.1.3 Rationale for the Proposed BAT Technology

BAT represents the best available economically achievable performance of facilities in an industrial subcategory or category taking into account factors specified in the CWA. The CWA factors considered in assessing BAT are the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, and non-water quality environmental impacts, including energy requirements and such other factors as the Administrator deems appropriate. See Section 304(b)(2)(B). In addition to technological availability, economic achievability is also a factor considered in setting BAT. See Section 301(b)(2)(A).

After considering all of the technologies described in Section 7, in light of the factors specified in Section 304(b)(2)(B) and Section 301(b)(2)(A) of the CWA, as appropriate, EPA is putting forth four preferred alternatives for BAT. These four preferred alternatives primarily differ in that some would establish more environmentally protective BAT requirements for discharges from two of the wastestreams from existing sources. Under the first preferred alternative, EPA is proposing to establish BAT effluent limits based on the technologies specified in Option 3a. With the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), the proposed rule under Option 3a would:

- Establish a "zero discharge" effluent limit for all pollutants in fly ash transport water and FGMC wastewater;
- Establish numeric effluent limits for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;
- Establish numeric effluent limits for copper and iron in discharges of nonchemical metal cleaning wastes;[47]
- Establish BAT effluent limits for bottom ash transport water and combustion residual leachate that are equal to the current BPT effluent limits for these discharges (i.e., numeric effluent limits for TSS and oil and grease; and
- BAT for discharges of FGD wastewater would continue to be determined on a site-specific basis.

Under the second preferred alternative for BAT, EPA is proposing to establish BAT effluent limits based on the technologies specified in Option 3b. With the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), the proposed rule under Option 3b would:

- Establish numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more;[48,49]
- Establish a "zero discharge" effluent limit for all pollutants in fly ash transport water and FGMC wastewater;
- Establish numeric effluent limits for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;
- Establish numeric effluent limits for copper and iron in discharges of nonchemical metal cleaning wastes;[50] and
- Establish BAT effluent limits for bottom ash transport water and leachate that are equal to the current BPT effluent limits for these discharges (i.e., numeric effluent limits for TSS and oil and grease).

Under the third preferred alternative for BAT, EPA is proposing to establish BAT effluent limits based on the technologies specified in Option 3. In addition to the requirements

[47] As described later in this section, EPA is proposing to exempt from new BAT copper and iron limitations existing discharges of nonchemical metal cleaning wastes that are currently authorized under their existing NPDES permit without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits for low volume waste.

[48] Total plant-level wet-scrubbed capacity is calculated by summing the nameplate capacity for all of the units that are serviced by wet FGD systems.

[49] For units below the 2,000 MW threshold, BAT would continue to be determined on a site-specific basis.

[50] As described later in this section, EPA is proposing to exempt from new BAT copper and iron limitations existing discharges of nonchemical metal cleaning wastes that are currently authorized under their existing NPDES permit without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits for low volume wastes.

described for Option 3b, the proposed rule would establish the same numeric effluent limits as in Option 3b for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater from units located at all steam electric facilities, with the exception of oil-fired generating units and small generating units (i.e., 50 MW or less).

Under the fourth preferred alternative for BAT (Option 4a), in addition to the requirements described for Option 3, the proposed rule would establish "zero discharge" effluent limits for all pollutants in bottom ash transport water from units greater than 400 MW.

For oil-fired generating units and small generating units (i.e., 50 MW and smaller) that are existing sources, under all four preferred options, EPA is proposing to set the BAT effluent limits equal to the current BPT effluent limits for copper and iron for nonchemical metal cleaning wastes, and for TSS and oil and grease for five of the six wastestreams listed above (i.e., FGD wastewater, fly ash transport water, FGMC wastewater, leachate from landfills and surface impoundments containing combustion residuals, and gasification wastewater).[51] EPA is proposing Options 3a, 3b, 3 and 4a as the preferred BAT regulatory options because its analysis to this date suggests that they are all technologically available, economically achievable, and have acceptable non-water quality environmental impacts. However, EPA is putting forth a range of options as candidates for BAT in order to enhance the Agency's understanding of the pros and cons of each of these options in light of the statutory factors through the public comment process and intends to evaluate this information and how it relates to the factors specified in the CWA. As discussed above in Section 7 and 8.1.2, the data in EPA's record and its analysis to date suggests that all four options are technologically available. EPA's record indicates that the technologies comprising Options 3a, 3b, 3, and 4a are well-demonstrated and have been employed at a subset of existing power plants.

Under all of the preferred options, the technology basis for fly ash transport water is dry handling. All generating units built in the 30 years since the ELGs were last revised in 1982 have been subject to a zero discharge standard for the pollutants in fly ash transport water, in nearly all cases installing dry fly ash handling technologies to comply with the standard. In addition, many other generating units that could discharge their fly ash transport water upon meeting a TSS effluent limit have instead retrofitted the dry fly ash handling technology to meet operational needs or for economic reasons. Approximately 40 percent of the plants that were operating wet-sluicing systems in 2000 have converted generating units to dry fly ash (approximately 115 generating units at 45 power plants). Another 61 generating units are slated to convert to dry fly ash handling by 2020. Based on data collected by the industry survey, approximately 66 percent of coal- and petroleum coke-fired generating units handle all fly ash with dry technologies. Another 15 percent of coal- and petroleum coke-fired generating units have both wet and dry fly ash handling systems (typically, the wet system is a legacy system that the plant has not decommissioned following retrofit with a dry system). Only 19 percent of coal- and petroleum coke-fired generating units exclusively use a wet fly ash handling system. Furthermore, some of these plants with wet fly ash handling systems manage the ash handling process so that they do

[51] As described later in this section, EPA is proposing to exempt from new BAT copper and iron limitations existing discharges of nonchemical metal cleaning wastes that are currently authorized under their existing NPDES permit without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits for low volume waste.

not discharge fly ash transport water. As a result, EPA determined that only 13 percent of coal-fired power plants would incur costs to comply with a BAT zero discharge requirement for fly ash transport water.

Power plants recently began installing FGMC systems either to comply with state requirements or to prepare for emissions limits established by the MATS rule. Plants using sorbent injection systems (e.g., activated carbon injection) typically handle the spent sorbent in the same manner as their fly ash. Nearly all plants with FGMC systems use dry handling technologies. Only a few plants use wet systems to transport the spent sorbent to disposal in surface impoundments. Based on the industry survey, the plants using wet handling systems currently operate them as closed-loop systems and do not discharge FGMC wastewater to surface waters, or have the capability to do so. These plants could continue to operate these wet systems as closed-loop systems, or could convert to dry handling technologies by managing the fly ash and spent sorbent together in a retrofitted dry system (the wastes are currently managed together in the impoundments) or by installing dedicated dry handling equipment for the FGMC wastes similar to the equipment used for fly ash.

The technology basis for control of discharges of FGD wastewater under Options 3b (for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more), 3, and 4a is chemical precipitation followed by anaerobic biological treatment. Four power plants, or approximately three percent of wet-scrubbed power plants that discharge FGD wastewater already have the Options 3b (for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more), 3, and 4a BAT technology in place. Under Options 3b (for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more), 3, and 4a, in addition to other new requirements that would be established, numeric limits would be established for toxic discharges including arsenic, mercury, and selenium from FGD wastewater.

The technology used as the basis for FGD wastewater treatment under Options 3b (for units at plants with a total wet-scrubbed capacity of 2,000 MW or more), 3, and 4a has been tested at power plants for more than 10 years and full-scale systems have been operating at a subset of plants for 5 years. The biological treatment processes used in the bioreactor portion of the treatment technology have been widely used in many industrial applications for decades both in the U.S. and internationally. Five steam electric power plants operate fixed-film anoxic/anaerobic biological treatment systems to treat FGD wastewater and another operates a suspended growth biological treatment system that targets removal of selenium.[52] Other power plants are considering installing the biological treatment technology to remove selenium and at least one plant is moving forward with construction [ERG, 2013c]. In addition, four additional power plants currently operate anaerobic biological treatment systems for their FGD wastewater, indicative that this is available technology. EPA is aware of industry concerns with the feasibility of biological treatment at some power plants. Specifically, industry has asserted that the efficacy of these systems is unpredictable, and is subject to temperature changes, high chloride concentrations, and high oxidation reduction potential in the absorber (which may kill the treatment bacteria). EPA’s record to date does not support these assertions, but is interested in additional information that addresses these concerns.

[52] Four of the six operate the biological treatment systems in combination with chemical precipitation.

More than one-third of plants that discharge FGD wastewater utilize chemical precipitation (in some cases, also using additional treatment steps). As noted above, four power plants currently operate chemical precipitation systems in combination with anaerobic biological treatment systems. The chemical precipitation treatment processes included in the FGD wastewater technology basis for these options are used at 24 percent of steam electric power plants that discharge FGD wastewater (and another 11 percent of plants also use chemical precipitation systems that could be upgraded to this technology basis) and also at thousands of industrial facilities nationwide, including Metal Products and Machinery facilities, Iron & Steel manufacturers, and metal finishers [U.S. EPA, 2003; U.S. EPA, 2002; U.S. EPA, 1983].[53]

Option 3b proposes limitations based on this technology for units at the largest plants (as determined by a 2,000 MW total wet-scrubbed capacity threshold), and BAT for the control of discharges of FGD wastewater from units at plants below this threshold would continue to be determined on a site-specific basis. For FGD wastewater only, EPA believes any threshold should be based on a plant level rather than a unit level because many plants currently use a single FGD treatment systems to service multiple units. Additionally, EPA determined that wet-scrubbed capacity is an appropriate metric because it only reflects units that are generating FGD wastewater. For example, a plant could have a total plant nameplate generating capacity of 3,500 MW, but only have a wet-scrubbed capacity of 200 MW if only one of its units is wet-scrubbed. EPA is putting forth this option as a preferred option based on an assumption that these facilities are more able to achieve these limits based on economies of scale. These largest facilities will likely also be able to absorb the costs of installing and operating the chemical precipitation and anaerobic biological treatment systems on which the FGD wastewater limitations are based. For these reasons, as well as those specified above related to current innovation and treatment trends, Option 3b proposes that BAT effluent limitations for discharges of FGD wastewater would continue to be determined on a site-specific basis for units at facilities below the 2,000 MW threshold.

The fourth preferred alternative for this proposed rule, Option 4a, in addition to the requirements that would be established under Option 3, would eliminate discharges of pollutants in bottom ash transport water from units greater than 400 MW. The technology basis for bottom ash for the zero discharge requirement is dry handling or a closed-loop system. Bottom ash transport water is one of the three largest sources for discharges of the pollutants of concern from steam electric power plants and these discharges occur at many power plants across the nation. Based on data collected by the industry survey, approximately 30 percent of coal-fired and petroleum coke-fired power plants handle bottom ash using technologies that do not generate any transport water. In addition, another 12 percent of coal- and petroleum coke-fired power plants manage the wet-sluicing bottom ash handling system as a closed-loop system that recirculates all bottom ash transport water so that it is not discharged. In addition, 83 percent of coal-fired generating units built in the last 20 years installed dry bottom ash handling systems.

EPA recognizes that the potential costs associated with compliance with a zero discharge standard for discharges of bottom ash transport water would be substantial if applied to all

[53] Physical/chemical treatment systems can be effective at removing mercury and certain other metals; however, to achieve effective removal of selenium this technology must be coupled with additional treatment technology such as anoxic/anaerobic biological treatment.

facilities (for example, approximately half of Option 4 costs and approximately a third of Option 5 costs), and, therefore, EPA looked carefully at this wastestream with a particular focus on generating unit size. EPA's review demonstrated that, in the case of bottom ash transport water, units less than or equal to 400 MW are more likely to incur compliance costs that are disproportionately higher per MW than those incurred by larger units. For example, the average annualized cost of achieving zero discharge limits for bottom ash discharges (i.e. dry handling or closed loop) per MW for a 200 MW unit is more than three times higher than the average cost for a 400 MW unit. Based on the data from the industry survey, EPA estimates that 25 percent of coal-fired power plants would incur costs to comply with a BAT zero discharge requirement for bottom ash transport water from units greater than 400 MW.

Furthermore, while all plants, regardless of size, are capable of installing and operating dry handling or closed-loop systems for bottom ash transport water, and the costs would be affordable for most plants, EPA believes that companies may choose to shut down 400 MW and smaller units instead of making new investments to comply with proposed zero discharge bottom ash requirements. EPA is basing this belief on its review of units that facilities have announced will be retired or converted to non-coal based fuel sources. Of those units that plants have announced for retirement, and that also generate bottom ash transport water, over 90 percent are 400 MW or less [ERG, 2013d]. Therefore, for the reasons specified above, for units less than or equal to 400 MW, Option 4a proposes to set the BAT effluent limits equal to the current BPT effluent limits based on surface impoundments.

The two IGCC plants currently operating in the United States use the technology that is the basis for all four preferred options for gasification wastewater. A third IGCC plant that will soon begin commercial operation will also use the technology and, in addition to that, will also operate a cyanide destruction step as part of the treatment system.

For all four preferred options, the proposed BAT limits for copper and iron in discharges of nonchemical metal cleaning waste are equal to the current BPT effluent limits for these pollutants in metal cleaning waste. These effluent limits are based on the same technology that was used as the basis for the current ELG BPT requirements for metal cleaning waste (i.e., chemical precipitation).

Discharges of metal cleaning wastes that are generated from cleaning metal process equipment without chemical cleaning compounds (i.e., nonchemical metal cleaning waste) are already subject to BPT effluent limits for copper and iron equal to the BAT effluent limits in the proposed rule. Based on responses to the industry survey, facilities typically treat both chemical and nonchemical metal cleaning waste in similar fashion.

Since, as described above, nonchemical metal cleaning waste is included within the definition of metal cleaning waste, and copper and iron are already regulated under metal cleaning wastes, EPA would be establishing BAT limits equal to the BPT limits (for copper and iron) that already apply to these wastes. As a result, facilities should incur no cost to comply with the proposed BAT for these wastes. However, EPA recognizes that previous guidance provided after the final 1974 regulation stated that wastes from metal cleaning with water are considered "low volume" wastes. The extent to which this statement was relied upon is unclear, and EPA rejected the guidance in the 1982 rulemaking for the steam electric ELGs (47 FR 52297).

However, because permitting authorities and others may have relied on this guidance and the potential costs to those facilities are not known, EPA is proposing to exempt from any new copper and iron BAT requirements those discharges of nonchemical metal cleaning waste to which this guidance was applied in the past. In other words, EPA is proposing to exempt from proposed new copper and iron BAT limitations those discharges of nonchemical metal cleaning wastes from generating units that are currently authorized to discharge nonchemical metal cleaning wastes without copper and iron limits pursuant to existing BPT requirements for metal cleaning waste. For such discharges, EPA is proposing to set BAT limitations equal to BPT limitations for low volume waste.

To get a better understanding of how discharges of nonchemical metal cleaning wastes are currently permitted, EPA's regional offices recently reviewed 45 permits for plants that EPA had reason to believe generated nonchemical metal cleaning waste based on responses to the industry survey. For these permits, EPA determined the following based on the review:

- 64 percent of the plants are either zero discharge of metal cleaning wastes or have to comply with copper and iron limits;
- 27 percent of plants do not have to comply with copper and iron limits; and
- 9 percent of plant permits do not include enough information to determine whether the plant would be in compliance with the proposed BAT limitations.

While not exhaustive, this review provides some information to suggest that many, but not all, plants are either zero discharge or have iron and copper limits and thus are already meeting the proposed BAT limitations. For additional information on the permit review conducted, see Section 7.7.

In order to implement the exemption proposed for certain discharges of nonchemical metal cleaning waste that have historically been treated as low volume wastes and not subject to copper and iron limits under metal cleaning waste BPT requirements, EPA's current thinking is to develop a specific list of generating units eligible for the exemption. Therefore, EPA is seeking to identify those generating units that should be eligible for the exemption through the public comment process on this rulemaking. To qualify for the proposed exemption, the generating unit must meet all three of the following criteria:

- The generating unit must currently generate nonchemical metal cleaning wastes;
- The generating unit must discharge the nonchemical metal cleaning waste; and
- The generating unit must be located at a plant that is authorized to discharge the nonchemical metal cleaning waste without limitations for copper and iron.

If the nonchemical metal cleaning wastes generated and discharged by a generating unit do not meet all of these three criteria, then EPA proposes that the generating unit will not be eligible for the exemption. For example, if the plant currently hauls the nonchemical metal cleaning wastes off site for disposal, the generating units associated with the nonchemical metal cleaning waste generation would not be exempt. Another approach EPA is considering would be to define the conditions of the exemption, and then make it available to any facility that qualified, regardless of whether the facility was identified to EPA during the comment period.

This would give EPA less information on the potential effects of including this exemption in the final rule, but would also allow qualified facilities to make use of the exemption even if they were unaware of the need to file comments during the comment period in order to make use of it.

EPA is also considering setting BAT limitations equal to BPT limitations applicable to metal cleaning waste for all discharges of nonchemical metal cleaning wastes (i.e., not creating an exemption from copper and iron limits for discharges of nonchemical metal cleaning wastes from generating units currently authorized to discharge those wastes without copper and iron limits). As part of this approach, EPA is evaluating whether plants would incur costs to comply with the current BPT requirements applicable to discharges of metal cleaning wastes.

EPA's analysis to date suggests that all four preferred options, Option 3a, Option 3b, Option 3, and Option 4a, are economically achievable. EPA performed cost and economic impact assessments using the Integrated Planning Model (IPM) for Option 3 and Option 4.[54] Option 4 is more costly than any of the four preferred options including Option 4a; therefore by performing the assessments with these two options, EPA can evaluate the potential effects of each of the preferred options. Because the costs and the facilities affected by Option 3a and 3b are a subset of Option 3, EPA can use the results of Option 3 to inform the potential impacts of Option 3a and Option 3b. In a similar way, because the costs and the facilities affected by Option 4a are a subset of Option 4, EPA can use the results of Option 4 to inform the potential impacts of Option 4a.

For the options analyzed overall, the model showed very small effects on the electricity market, on both a national and regional sub-market basis. Based on the results of these analyses, EPA estimates that the proposed requirements associated with Option 3a, Option 3b, and Option 3 would not lead to the premature retirement of any steam electric generating units (i.e., no partial or full plant closures).

The results for Option 4 show fourteen unit (partial) closures and zero plant (full) closures projected as of the model year 2030, reflecting full compliance of all facilities.[55,56] The 14 generating units are located at six plants. The IPM results also show that five steam electric units that are projected to close under the base case (i.e., in the absence of the proposed revisions to the ELG) would remain operating under proposed Option 4 (i.e., avoiding closure). As a result, for Option 4, the IPM analysis projects total net closure of nine generating units, with total combined generating capacity of 317 MW. These results support EPA's conclusion that Option 4 is economically achievable. As explained above, because the costs and facilities affected by Option 4a are only a subset of Option 4 (i.e., are less than those for Option 4), the model would project similar or smaller effects for Option 4a. These IPM estimates for closures and avoided

[54] IPM is a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. See the *Regulatory Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for additional details.

[55] As used here for the purpose of this rulemaking, the term partial closure refers to a plant where the closure of a generating unit is projected, but one or more generating units at the plant will continue operating. A full closure refers to a situation where all generating units at a plant are projected to shut down.

[56] Given the design of IPM, unit-level and thereby plant-level projections are presented as an indicator of overall regulatory impact rather than a prediction of future unit–level or plant-specific compliance actions.

closures also support EPA's conclusion that Option 4a is economically achievable for the steam electric industry.

As part of its consideration of technological availability and economic achievability, EPA also considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the requirements of the rule. As described in greater detail in Section 14, EPA is proposing that, where the limitations and standards being proposed for existing direct and indirect dischargers are more stringent than existing BPT requirements, those limitations and standards do not begin to apply until July 1, 2017 (approximately three years following promulgation of the final rule). EPA is proposing this approach to provide the time that many facilities will need to raise capital, plan and design systems, procure equipment, and construct and then test systems. Moreover, this approach will enable facilities to take advantage of planned shutdown or maintenance periods to install new pollution control technologies. EPA's proposal is designed to minimize any potential impacts on electricity availability caused by forced outages.

Options 3a, 3b, 3 and 4a have acceptable non-water quality environmental impacts, as discussed in Section 12. EPA estimates that Options 3a, 3b, 3, and 4a would increase energy consumption by less than 0.003 percent, less than 0.004 percent, less than 0.008 percent, and less than 0.012 percent, respectively, of the total electricity generated by power plants. EPA also estimates that Options 3a, 3b, 3, and 4a would increase the amount of fuel consumed by increased operation of motor vehicles (e.g., for transporting fly ash) by less than 0.009 percent, less than 0.009 percent, less than 0.009 percent, and less than 0.014 percent, respectively, of total fuel consumption by all motor vehicles.

As discussed in Section 12.2, EPA also evaluated the effect of the proposed rule on air emissions generated by power plants (NO_x, sulfur oxides (SO_x), and CO_2). For Options 3a, 3b, and 3, the NO_x emissions are estimated to increase by no more than 0.12 percent, and for Option 4a, by no more than 0.13 percent. EPA projects no significant increase in emissions of SO_x or CO_2 under the four preferred options.

EPA also evaluated the effect of the proposed rule on solid waste generation and water usage. There would be no increase in solid waste generation under Option 3a, and EPA estimates that solid waste generation at power plants will increase by less than 0.001 percent under the other three preferred options. EPA estimates the power plants would reduce water use by 50 billion gallons per year (136 million gallons per day) under Option 3a, 52 billion gallons per year (143 million gallons per day) under Option 3b, 53 billion gallons per year (144 million gallons per day) under Option 3, and 103 billion gallons per year (282 million gallons per day) under Option 4a.

EPA also examined the effects of the preferred options on consumers as an "other factor" that might be appropriate when considering what level of control represents BAT. If all compliance costs were passed on to residential consumers of electricity instead of being borne by the operators and owners of power plants, the monthly increase in electricity bill would be no more than $0.04, $0.06, $0.13, and $0.22, respectively under Options 3a, 3b, 3, and 4a.

EPA is not proposing either Option 1 or Option 2 as its preferred option for BAT because neither option would represent the best available technology level of control for steam electric power plant discharges. For example, Options 1 and 2 would allow plants to continue to discharge fly ash transport wastewater without treating the wastes to remove dissolved metals and many of the other pollutants present in the wastewater. However, 66 percent of all coal- and petroleum coke-fired generating units that produce fly ash as a residue of the combustion process already use dry fly ash technologies to manage all of their fly ash without any associated creation or discharge of fly ash transport water. And another 15 percent of the coal- and petroleum coke-fired generating units that produce fly ash also already operate dry fly ash handling systems in addition to a wet ash handling system (either as a completely redundant system, or to manage a fraction of the fly ash that is produced during combustion). Similarly, every generating unit operating a FGMC system does so in a manner that avoids creating any FGMC wastewater (92 percent of units with FGMC), or manages the FGMC wastewater in a closed cycle process that does not result in a discharge to surface water (8 percent of units with FGMC). The technology serving as the basis for FGD effluent limits under Option 1 is not effective at removing many of the pollutants of concern in FGD wastewater, including selenium, nitrogen compounds, and certain metals that contribute to high concentrations of total dissolved solids in FGD wastewater (e.g., bromides, boron). Furthermore, the information in the record for this proposed rule demonstrates that the amount of mercury, selenium, and other pollutants removed by the biological treatment stage of the treatment system, above and beyond the amount of pollutants removed in the chemical precipitation treatment stage preceding the bioreactor, can be substantial. Options 1 and 2 would remove fewer or similar levels of pollutants to the preferred options, all of which EPA believes, based on its analysis to date, to be technologically available, economically achievable, and have acceptable non-water quality environmental impacts. Options 1 and 2 would establish new effluent limits for three of the seven key wastestreams addressed in this rulemaking. For the remaining four wastestreams, BAT effluent limits would be set equal to the current BPT effluent limits.

EPA did not select Option 4 as its preferred regulatory option because of concerns expressed above associated with the projected compliance costs associated with zero discharge requirements for bottom ash for units equal to or below 400 MW. The bottom ash requirements for Option 4 and the preferred Option 4a are the same with the exception that Option 4a proposes to set the BAT effluent limits for bottom ash transport water equal to the current BPT effluent limits for units less than or equal to 400 MW, while Option 4 would set the BAT effluent limits for bottom ash transport water equal to the BPT effluent limits for units less than or equal to 50 MW. All other units would be subject to “zero discharge” effluent limits for all pollutants in bottom ash transport water.

Moreover, Option 4 proposes to establish BAT discharge limitations for toxic discharges for leachate. The record demonstrates that the amount of pollutants collectively discharged in leachate by steam electric plants is a very small portion of the pollutants discharged collectively for all steam electric power plants (i.e., less than ½ a percent). The technology basis for limitations on discharges of combustion residual leachate proposed under Option 4 is chemical precipitation. Because of the relatively low level of pollutants in this wastestream, and because EPA believes this is an area ripe for innovation and improved cost effectiveness, EPA is not putting forward this option as a preferred option. On balance, EPA would like to collect additional information on costs and effectiveness of chemical precipitation and other possible technologies for reducing pollutants discharged in leachate before making a finding with respect to what technologies represent the best available technology economically achievable for controlling discharges of pollutants found in combustion residual leachate.

EPA did not select Option 5 as its preferred option for BAT because of the high total industry cost for the option ($2.3 billion/year annualized social cost) and because of preliminary indications that Option 5 may not be economically achievable. While EPA has traditionally looked at affordability of the rule to the regulated industry, EPA has in some limited instances over the past three decades rejected an option primarily on the basis of total industry costs. See 48 FR 32462, 32468 (July 15, 1983) (Final Rule establishing ELGs for the Electroplating and Metal Finishing Point Source Categories); 74 FR 62996, 63026 (Dec. 1, 2009) (Final Rule establishing ELGs for the Construction and Development Point Source Category); *BP Exploration & Oil, Inc. v. EPA*, 66 F.3d 784, 796-97 (6th Cir. 1996) (upholding EPA's decision not to require zero discharge of produced waters based on reinjection for the Offshore subcategory of the Oil and Gas Extraction Point Source Category based in part on total industry cost). EPA similarly finds this appropriate here. In addition, certain screening-level economic impact analyses indicated that compliance costs may result in financial stress to some entities owning steam electric plants. Although EPA did not select Option 5 as the preferred BAT option, without question, Option 5 would remove the most pollutants from steam electric power plant discharges. Also, the technologies are all potentially available and may be appropriate (individually or in totality) as the basis for water quality-based effluent limits in NPDES permits, depending on site-specific conditions. For example, any of the requirements that would be established under Option 5, including at a minimum the vapor-compression evaporation technology serving as the Option 5 technology basis for FGD wastewater, may be appropriate for those power plants that discharge upstream of drinking water treatment plants and that have bromide releases in wastewaters that impact treatment of source waters at the drinking water treatment plants. See the *Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for additional discussion about discharges of bromides.

For the reasons described in Section 8.2, EPA is proposing that, where the limitations and standards in the proposed rule are more stringent than existing BPT requirements, those limitations and standards do not begin to apply until July 1, 2017 (approximately three years from the effective date of this rule).

For all eight of the main BAT options under consideration, EPA is proposing to establish effluent limits for oil-fired generating units and small generating units (i.e., 50 MW or less) that differ from the effluent limits for all other generating units.[57] For oil-fired generating units and small generating units, EPA is proposing to set the BAT effluent limits equal to the current BPT effluent limits for all seven of the key wastestreams addressed by this proposed rule. For six of these wastestreams, BAT would be set equal to current BPT numeric limits for TSS and oil and grease, with these pollutants regulated as indicator pollutants for the control of toxic and nonconventional pollutants. For nonchemical metal cleaning wastes, EPA is proposing to set BAT equal to the current BPT effluent limits for copper and iron in metal cleaning wastes, but

[57] For Option 4a, for discharges of pollutants found in bottom ash transport water only, as explained previously, EPA is proposing to raise the value from less than or equal to 50 MW to less than or equal to 400 MW.

would not establish BAT effluent limits for TSS and oil and grease (which are also currently regulated by BPT for metal cleaning wastes).[58] EPA's proposal and reasoning is detailed in subsections 8.1.3.1 and 8.1.3.2.

In addition, EPA has identified some differences among the options in terms of cost effectiveness. The *Regulatory Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* describes EPA's cost-effectiveness analysis for the preferred regulatory options. EPA's analysis to date shows that the average cost effectiveness ($1981/TWPE) under Option 3a, 3b, 3, and 4a for existing direct dischargers is $27, $31, $44, and $57, respectively. This demonstrates that Option 3a is the most cost effective of the preferred options, Option 4a is the least cost effective of the preferred options, and Option 3 and Option 3b are between the two.

EPA also calculated the cost-effectiveness of particular controls for the wastestreams that would be controlled under the preferred options for existing direct dischargers.[59] The cost-effectiveness for zero discharge of fly ash transport and FGMC wastewater, as in Option 3a, is $27 per TWPE removed. The cost effectiveness of chemical precipitation alone is $70 per TWPE removed, while the cost effectiveness of chemical precipitation plus anaerobic biological treatment, which is included in all options except Option 3a, is $60 per TWPE removed. The cost effectiveness of zero discharge of bottom ash transport water for all units more than 50 MW is $107 per TWPE. In comparison, when this requirement is applied only to units more than 400 MW, as in Option 4a, the cost effectiveness value is $99 per TWPE removed.

Thus, the cost effectiveness for control of the various wastestreams included within the preferred options ranges from $27-$107 per TWPE in $1981; with zero discharge controls on fly ash transport wastewater being the most cost-effective, zero discharge controls on bottom ash transport wastewater being the least cost effective, and controls for FGD wastewater based on chemical precipitation in combination with anaerobic biological treatment between the two.

8.1.3.1 Effluent Limits for Oil-Fired Generating Units

EPA is proposing to establish BAT limits equal to BPT for existing oil-fired units. For the purpose of the proposed BAT effluent limits, oil-fired generating units would be those that use oil as either the primary or secondary fuel and do not burn coal or petroleum coke. Units that use oil only during startup or for flame stabilization would not be considered oil-fired generating units. EPA is proposing to set BAT limits equal to BPT for existing oil-fired units because, in comparison to coal- and petroleum coke-fired units, oil-fired units generate substantially fewer pollutants, are generally older and operate less frequently, and in many cases are more susceptible to early retirement when faced with compliance costs attributable to the proposed ELGs.

[58] As described earlier in this section, EPA is proposing to exempt from new BAT copper and iron limitations existing discharges of nonchemical metal cleaning wastes that are currently authorized under their existing NPDES permit without iron and copper limits. For these discharges, BAT limits would be set equal to BPT limits for low volume waste.

[59] While it is not included in the preferred options as a wastestream with additional controls, EPA also looked at the cost effectiveness of controlling leachate using chemical precipitation and this value would exceed $1,000 per TWPE removed.

The amount of ash generated at oil-fired units is a small fraction of the amount produced by coal-fired units. Coal-fired units generate hundreds or thousands of tons of ash each day, with some plants generating more than 1,500 tons per day of ash. In contrast, oil-fired units generate less than one ton of ash per day. This disparity is also apparent when comparing the ash tonnage to the amount of power generated, with coal-fired units producing nearly 300 times more ash than oil-fired units (0.04 tons per MW-hour on average for coal units; 0.000145 tons per MW-hour on average for oil units). The amount of pollutants discharged to surface waters is roughly correlated to the amount of ash wastewater discharged, thus oil-fired units discharge substantially less pollutants to surface waters than a coal-fired unit even when generating the same amount of electricity. EPA estimates that if BAT effluent limits for oil-fired units were set equal to either the proposed Option 3 or Option 4a limits for coal-fired units (>50 MW), the total industry pollutant reductions attributable to the proposed rule would increase by less than one percent.

Oil-fired units are generally among the oldest steam electric units in the industry. Eighty-seven percent of the units are more than 25 years old. In fact, more than a quarter of the units began operation more than 50 years ago. Based on responses to the industry survey, only 20 percent of oil-fired units operate as baseload units; the rest are either cycling/intermediate units (45 percent) or peaking units (35 percent). These units also have notably low capacity utilization. While a quarter of the baseload units report capacity utilization greater than 75 percent, most baseload units (60 percent) report a capacity utilization of less than 25 percent. Eighty percent of the cycling/intermediate units and all peaking units also report capacity utilization less than 25 percent. Thirty-five percent of oil-fired units operated for more than six months in 2009; nearly half of the units operated for less than 30 days.

As shown above, oil-fired units are generally older and operate intermittently (i.e., they are peaking, cycling, or intermediate units). While these oil-fired units are capable of installing and operating the treatment technologies evaluated as part of this rulemaking, and the costs would be affordable for most of the plants, EPA believes that, due to the factors described here, companies may choose to shut down these oil-fired units instead of making new investments to comply with the rule. If these units shut down, it could reduce the flexibility that grid operators have during peak demand because there would be less reserve generating capacity to draw upon. But more importantly, maintaining a diverse fleet of generating units that includes a variety of fuel sources is vital to the nation's energy security. Because the supply/delivery network for oil is different from other fuel sources, maintaining the existence of oil-fired generating units helps ensure reliable electric power generation. Thus, the oil-fired generating units add substantially to electric grid reliability and the nation's energy security.

Based on responses to the industry survey, EPA estimates that less than 20 oil-fired units discharged fly ash or bottom ash transport water in 2009. At the same time, EPA notes that many oil-fired units operate infrequently, which could contribute to the relatively low numbers of units discharging ash-related wastewater. Should more widespread operation of oil units be required to meet demands of the electric grid, additional plants may find it necessary to discharge ash transport water. Because of the operating conditions unique to the existing fleet of oil-fired units and potential effects on the nation's electric power grid, a non-water quality environmental impact that EPA considers under Section 304(b) of the CWA, EPA believes it is appropriate to set BAT effluent limits for oil-fired equal to the current BPT limits.

8.1.3.2 Effluent Limits for Small Generating Units

EPA is proposing to establish BAT effluent limits equal to BPT for existing small generating units, which would be defined as those units with a total nameplate generating capacity of 50 MW or less.[60] Small units are more likely to incur compliance costs that are disproportionately higher per amount of energy produced than those incurred by large units because they are not as able to take advantage of economies of scale. For example, the unit-level annualized cost for the proposed FGD wastewater treatment technology under Option 3 (chemical precipitation plus biological treatment) is approximately seven times more expensive on a dollar-per-megawatt basis for small generating units, relative to units larger than 50 MW. Similarly, the unit-level annualized cost to convert the fly ash handling system to dry technology (conveyance equipment and intermediate storage silos) is more than four times more expensive on a dollar-per-megawatt basis for small generating units, relative to units larger than 50 MW. For Option 4, bottom ash conversions are more than six times more expensive for small units, on a dollar-per-megawatt basis.

Moreover, the record demonstrates that the amount of pollutants collectively discharged by small generating units is a very small portion of the pollutants discharged collectively for all steam electric power plants (e.g., less than 1 percent under Option 3). As a result, setting BAT limits equal to BPT for existing steam electric generating units with a capacity of 50 MW or less will have little impact on the pollutant removals for the overall rule.

EPA considered establishing the size thresholds for small generating units at 25 MW because that threshold is already used for this industry sector in some regulatory contexts. For example, the Clean Air act defines an “electric utility generating unit” as “any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.” CAA Section 112(a)(8), 42 U.S.C. 7412(a)(8). The existing ELGs for the steam electric power generating point source category also include different effluent limitations for plants with total rated generating capacity of less than 25 MW. See 40 CFR 423.13(c)(1) and 423.15(i)(1).

EPA currently proposes a threshold of 50 MW rather than 25 MW because the proposed 50 MW threshold would do more to alleviate potential impacts. [61,62] EPA recognizes that any attempt to establish a size threshold for generating units will be imperfect due to individual differences across units and firms. However, EPA believes that a threshold of 50 MW or less reasonably and effectively targets those generating units that should receive different treatment based on the considerations described above.

[60] Preferred Option 4a would increase this threshold for purposes of discharges of pollutants in bottom ash transport water only, to 400 MW or less.

[61] For Option 4a, for bottom ash transport water only, as explained previously, EPA is proposing to raise the value from less than or equal to 50 MW to less than or equal to 400 MW.

[62] As discussed in Section XVII.C, the proposed 50 MW threshold also alleviates potential impacts which may be borne by small entities or municipalities.

8.1.4 Rationale for the Proposed Best Available Demonstrated Control/NSPS Technology

Section 306 of the CWA directs EPA to promulgate New Source Performance Standards, or NSPS, "for the control of the discharge of pollutants which reflects the greatest degree of effluent reduction which the Administrator determines to be achievable through application of the best available demonstrated control technology, processes, operating methods, or other alternatives, including, where practicable, a standard permitting no discharge of pollutants." Congress envisioned that new sources could meet tighter controls than existing sources because of the opportunity to incorporate the most efficient processes and treatment systems into the facility design. As a result, NSPS should represent the most stringent controls attainable through the application of the best available demonstrated control technology, or BADCT, for all pollutants (that is, conventional, nonconventional, and priority pollutants).

After considering all of the technology options described in Section 7, EPA is proposing to establish NSPS based on the suite of technologies identified for Option 4 in Table 8-1. Thus, the proposed NSPS would do the following:

- Establish numeric effluent limits for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater;
- Maintain the current "zero discharge" effluent limit for all pollutants in fly ash transport water, and establish new "zero discharge" effluent limits for all pollutants in bottom ash transport water and FGMC wastewater;
- Establish numeric effluent limits for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;
- Establish numeric effluent limits for TSS, oil and grease, copper, and iron in discharges of nonchemical metal cleaning wastes; and
- Establish numeric effluent limits for mercury and arsenic in discharges of leachate.

The record indicates that the proposed NSPS is technologically available and demonstrated. The technologies that serve as the basis for Option 4 are all available based on the performance of plants using components of the suite of technologies within the past decade. For example, approximately a third of plants that discharge FGD wastewater utilize chemical precipitation (in some cases, also using additional treatment steps). Five plants operate fixed-film anoxic/anaerobic biological treatment systems for the treatment of FGD wastewater and another operates a suspended growth biological treatment system that targets removal of selenium.[63] EPA is aware of industry concerns with the feasibility of biological treatment at some power plants. Specifically, industry has asserted that the efficacy of these systems is unpredictable, and is subject to temperature changes, high chloride concentrations, and high oxidation reduction potential in the absorber (that may kill the treatment bacteria). EPA's record to date does not support these assertions, but is interested in additional information that addresses these concerns. Moreover, approximately 50 coal-fired generating units were built within the last 20 years and most (83 percent) manage their bottom ash without using water to transport the ash and, as a

[63] Four of the six operate the biological treatment systems in combination with chemical precipitation. Other power plants are considering installing the biological treatment technology to remove selenium, and at least one plant is moving forward with construction.

result, do not discharge bottom ash transport water. The Option 4 technologies in the proposed rule represent current industry practice for gasification wastewater. Every IGCC power plant currently in operation uses vapor-compression evaporation to treat the gasification wastewater, even when the wastewater is not discharged and is instead reused at the plant. In the case of FGMC wastewater, every plant currently using post-combustion sorbent injection (e.g., activated carbon injection) either handles the captured spent sorbent with a dry process or manages the FGMC wastewater so that it is not discharged to surface waters (or has the capability to do so). For leachate, as discussed in Section 7, chemical precipitation is a well-demonstrated technology for removing metals and other pollutants from a variety of industrial wastewater, including leachate from other landfills not located at power plants. It therefore represents the "greatest degree of effluent reduction…achievable" as that phrase is used in section 306 of the Clean Water Act.

The proposed NSPS for discharges of nonchemical metal cleaning waste are equal to the current BPT effluent limits that apply to discharges of these wastes from existing sources. As such, the proposed NSPS would be consistent with current industry practice for treating nonchemical metal cleaning waste and is based on the same technology that was used as the basis for the current NSPS for chemical metal cleaning waste. Based on responses to the industry survey, facilities typically treat both chemical and nonchemical metal cleaning waste in similar fashion.

The NSPS being proposed also poses no barrier to entry. The cost to install technologies at new units are typically less than the cost to retrofit existing units. For example, the cost differential between BAT Options 3 and 4 for existing sources is mostly associated with retrofitting controls for bottom ash handling systems. For existing generating units, the effluent requirements considered under Option 4a for BAT would cause those plants with units greater than 400 MW that discharge bottom ash wastewater to either modify their processes to become a closed-loop wet sluicing system, or retrofit modifications such as replacing the bottom of boilers to accommodate mechanical drag chain systems. For new sources, however, Option 4 would not present plants with the same choice of retrofit versus modification of existing processes. This is because every new generating unit already has to install some type of bottom ash handling system as the unit is constructed. Establishing a zero discharge standard for pollutants in bottom ash transport water as part of the NSPS means that power plants will install a dry bottom ash handling system during construction instead of installing a wet-sluicing system. EPA estimates that over the past 20 years, more than 50 new coal-fired generating units were built and that most of these units (83 percent) installed dry bottom ash handling systems.

Moreover, as described in the *Regulatory Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA assessed the possible impacts of Option 4 to new units by comparing the costs of the Option 4 technologies to the costs of a new generating unit as part of its Integrated Planning Model analyses. In both cases, the results show that the incremental costs that would be imposed by Option 4 do not present a barrier to entry. EPA estimated that the compliance costs for a new unit (capital and O&M) represent at most 1.5 percent of the annualized cost of building and operating a new 1,300 MW coal-fired plant, with capital costs representing less than 1 percent of the overnight construction costs, and annual O&M costs representing less than 5 percent of the cost of operating a new plant. IPM results show no barrier to new generation capacity during the model years in which all existing plants must be in compliance as a result of the BAT/NSPS compliance scenario.

Finally, EPA has analyzed non-water quality environmental impacts associated with Option 4 for existing sources, and its analysis is relevant to the consideration of non-water quality environmental impacts associated with Option 4 for new sources. EPA's analysis demonstrates that the non-water quality environmental impacts associated with Option 4 for existing sources are acceptable. Given that there is nothing inherent about a new unit that would alter the analysis for such sources, EPA believes that the non-water quality environmental impacts associated with the proposed NSPS regulatory option are, likewise, acceptable.

In contrast to the best available technology economically achievable, or BAT, that EPA is proposing for existing sources, the proposed NSPS would establish the same limits for oil-fired generating units and small generating units that are being proposed for all other new sources.[64] A key factor that affects compliance costs for existing sources is the need to retrofit new pollution controls to replace existing pollution controls. New sources do not trigger retrofit costs because the pollution controls (process operations or treatment technology) are installed at the time the new source is constructed. Thus, new sources are less likely than an existing source to experience financial stress by the cost of installing pollution controls, even if the pollution controls are identical.

EPA is not proposing regulatory Options 1 or 2, which would establish new effluent limits for only two of the seven key wastestreams addressed by this proposed rule, as its preferred option for NSPS. As explained above, neither of these two options represents the greatest degree of effluent reduction which the Administrator determines to be achievable through the best available demonstrated control technology.

EPA also did not select any of the preferred BAT regulatory Options (i.e., Options 3a, 3b, 3, or 4a) as its preferred option for NSPS because they would not control FGD wastewater (Option 3a and Option 3b for plants with a total wet-scrubbed capacity of less than 2,000 MW), bottom ash transport water (Option 3a, Option 3b, Option 3, and Option 4a for units less than or equal to 400 MW) or leachate discharges (Options 3a, 3b, 3, and 4a) and other, more effective, available technologies exist that do not present a barrier to entry and have acceptable non-water quality environmental impacts. EPA did not select preferred Option 3a for the same reasons it rejected Options 1 and 2. EPA did not select Options 3b, 3, or 4a because, under these regulatory options, NSPS effluent limits for bottom ash transport water for all or some portion of units and leachate would be set equal to the current BAT effluent limits on TSS and oil and grease, which are based on using surface impoundments.[65] The record demonstrates that zero discharge technologies are effective and available for managing bottom ash at new sources. Since these zero discharge technologies have been installed at 83 percent of coal-fired units built in the last 20 years, effluent standards based on surface impoundments do not represent Best Available Demonstrated Control Technology to control the discharge of pollutants in the bottom ash wastestream from new sources regardless of the unit size. In addition, the record demonstrates that chemical precipitation is a more effective technology than surface impoundments for

[64] As a point of clarification, this similarly holds true for bottom ash limitations.

[65] This rationale similarly applies to Option 3a.

controlling the pollutants present in leachate. For these reasons, Options 3b, 3 and 4a do not represent the best available demonstrated control technology to control the discharge of pollutants of concern from new sources.

EPA did not select Option 5 as its preferred option for NSPS because of its high costs, which are substantially higher than the costs for Option 4 and the other options evaluated for NSPS. See Section 9.10 for more information about the estimated compliance costs for the NSPS options. The cost differential between Options 4 and 5 is primarily due to the evaporation technology basis for controlling pollutants in FGD wastewater under Option 5.

Finally, EPA notes that Option 5 is comparable to Option 4 with respect to much of the anticipated pollutant removals, particularly the expected removals of arsenic, mercury, selenium and nitrogen. At the same time, Option 5 would control other pollutants in FGD wastewater that Options 1 through 4 do not effectively control, namely boron, bromides, and TDS. EPA is aware that bromide in wastewater discharges from steam electric power plants located upstream from a drinking water intake has been associated with the formation of trihalomethanes, also known as THMs, when it is exposed to disinfectant processes in water treatment plants. EPA recommends that permitting authorities consider the potential for bromide discharges to adversely impact drinking water intakes when determining whether additional water quality-based effluent limits may be warranted. Although EPA did not select Option 5 as the preferred NSPS option, the technologies forming the basis for Option 5 are all technologically available and may be appropriate (individually or in totality) as the basis for water quality-based effluent limits in individual or general permits depending on site-specific conditions.

8.1.5 Rationale for the Proposed PSES Technology

Section 307(b), 33 U.S.C. 1317(b), of the Clean Water Act requires EPA to promulgate pretreatment standards for pollutants that are not susceptible to treatment by POTWs or which would interfere with the operation of POTWs. EPA looks at a number of factors in selecting the technology basis for pretreatment standards. For existing sources, these factors are generally the same as those considered in establishing BAT. However, unlike direct dischargers whose wastewater will receive no further treatment once it leaves the facility, indirect dischargers send their wastewater to POTWs for further treatment. As such, EPA must also determine that a pollutant is not susceptible to treatment at a POTW or would interfere with POTW operations.

Table 8-2 summarizes the pass through analysis results for the BAT/NSPS pollutants for the various wastestreams and regulatory options. As shown in the table, all of the pollutants proposed for regulation under BAT/NSPS pass through.

Table 8-2. Summary of Pass Through Analysis

Technology Option	Pollutant	Pass Through? (Yes or No)
Chemical Precipitation for FGD Wastewater and/or Combustion Residual Leachate	Arsenic	Yes
	Mercury	Yes
Biological (one-stage chemical precipitation followed by anoxic/anaerobic biological) for FGD wastewater and/or Combustion Residual Leachate	Arsenic	Yes
	Mercury	Yes
	Nitrate Nitrite as N	Yes
	Selenium	Yes
Mechanical Vapor-Compression Evaporation for FGD Wastewater	Arsenic	Yes
	Mercury	Yes
	Selenium	Yes
	TDS	Yes
Mechanical Vapor-Compression Evaporation for IGCC Wastewater	Arsenic	Yes
	Mercury	Yes
	Selenium	Yes
	TDS	Yes
Nonchemical Metal Cleaning Wastes	Copper	Yes

EPA evaluated the same model technologies and regulatory options for PSES that it evaluated for BAT (described in Section 8.1.2). These standards would apply to existing generating units that discharge wastewater to POTWs.

As explained in Section 1.2.5, in selecting the PSES technology basis, the Agency generally considers the same factors as it considers when setting BAT, including economic achievability. Typically, the result is that the PSES technology basis is the same as the BAT technology basis. After considering all of the technology options described in Section 8.1.2, as is the case for BAT, EPA is proposing four preferred alternatives for PSES (i.e., Options 3a, 3b, 3, and 4a).

With the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), the proposed rule under Option 3a would:

- Establish a "zero discharge" effluent limit for all pollutants in fly ash transport water and FGMC wastewater;
- Establish numeric effluent limits for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;

- Establish numeric effluent limits for copper in discharges of nonchemical metal cleaning wastes;[66] and
- Establish BAT effluent limits for bottom ash transport water and leachate that are equal to the current BPT effluent limits for these discharges (i.e., numeric effluent limits for TSS and oil and grease)

With the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller), the proposed PSES under Option 3b would:

- Establish standards for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater for units located at plants with a total wet-scrubbed capacity of 2,000 MW;[67]
- Establish a "zero discharge" standard for all pollutants in fly ash transport water and FGMC wastewater;
- Establish standards for copper in discharges of nonchemical metal cleaning wastes;[68] and
- Establish standards for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater.

Under the third preferred alternative for PSES (Option 3), in addition to the requirements described for Option 3b, the proposed rule would establish the same standards for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater as for Option 3b from units at all steam electric facilities, with the exception of oil-fired generating units and small generating units (i.e., 50 MW or smaller).

Under the fourth preferred alternative for PSES (Option 4a), the proposed rule would establish "zero discharge" effluent limits for all pollutants in bottom ash transport water for units greater than 400 MW. All other proposed Option 4a requirements are identical to the proposed Option 3 requirements.

EPA is putting forth Options 3a, 3b, 3, and 4a as the Agency's preferred PSES regulatory options in order to confirm its understanding of the pros and cons of these options through the

[66] As described in Section VIII.A.3, EPA is proposing to exempt from new BAT copper and iron effluent limits existing discharges of nonchemical metal cleaning wastes that are currently authorized by an NPDES permit without iron and copper limits. This exemption also applies to any indirect discharges of nonchemical metal cleaning waste that are authorized without copper pretreatment standards. For such indirect discharges, the regulation would not specify PSES.

[67] Under Option 3b (for units located at plants with a total wet-scrubbed capacity of less than 2,000 MW), the regulations would not specify PSES for FGD wastewater, and POTWs would need to develop local limits to address the introduction of pollutants by steam electric power plants to the POTWs that cause pass through or interference, as specified in 40 C.F.R.403.5(c)(2).

[68]As described in Section VIII.A.3, EPA is proposing to exempt from new BAT copper and iron effluent limits existing discharges of nonchemical metal cleaning wastes that are currently authorized by an NPDES permit without iron and copper limits. This exemption also applies to any indirect discharges of nonchemical metal cleaning waste that are authorized without copper pretreatment standards. For such indirect discharges, the regulation would not specify PSES.

public comment process and intends to evaluate this information and how it relates to the factors specified in the CWA. For the same reasons identified in Section 8.1.3 for BAT, EPA's analysis to date suggests that for indirect dischargers as well as direct dischargers, the Option 3a, Option 3b, Option 3, and Option 4a technologies are available and economically achievable, and that the other regulatory options (Options 1, 2, 4, and 5) do not reflect the criteria for PSES. In addition, EPA has determined that these standards will prevent pass-through of pollutants from POTWs into receiving streams and also help control contamination of POTW sludge. EPA also considered the non-water quality environmental impacts and found them to be acceptable, as described in Section 12. Furthermore, for the same reasons that apply to EPA's preferred BAT options and described in Section 8.1.3, with the exception of numeric standards for copper in discharges of nonchemical metal cleaning wastes, EPA is proposing not to subject discharges from oil-fired generating units and small generating units (i.e., 50 MW or smaller) to POTWs to requirements based on Options 3a, 3b, 3, or Option 4a.[69,70]

Finally, similar to EPA's preferred BAT options and for the reasons supporting those options, for certain wastestreams, EPA is proposing that any new PSES discharge standards would apply to discharges of the regulated wastewater generated after July 1, 2017. See discussion in Section 14.

8.1.6 Rationale for the Proposed PSNS Technology

Section 307(c) of the CWA, 33 U.S.C. 1317(c), authorizes EPA to promulgate pretreatment standards for new sources (PSNS) at the same time it promulgates new source performance standards (NSPS). As is the case for PSES, PSNS are designed to prevent the discharge of any pollutant into a POTW that may interfere with, pass through, or may otherwise be incompatible with POTWs. In selecting the PSNS technology basis, the Agency generally considers the same factors it considers in establishing NSPS along with the results of a pass through analysis. As a result, EPA typically promulgates pretreatment standards for new sources based on best available demonstrated technology for new sources *See National Ass'n of Metal Finishers v. EPA*, 719 F.2d 624, 634 (3rd Cir. 1983). The legislative history explains that Congress required simultaneous establishment of new source standards and pretreatment standards for new sources for two reasons. First, Congress wanted to ensure that any new source industrial user achieve the highest degree of internal effluent controls necessary to ensure that such user's contribution to the POTW would not cause a violation of the POTW's permit. Second, Congress wished to eliminate from the new user's discharge any pollutant that would pass through, interfere, or was otherwise incompatible with POTW operations.

For the proposed ELGs, EPA evaluated the same model technologies and regulatory options for PSNS that it evaluated for NSPS (described in Section 8.1.4). These standards would apply to new generating units or new facilities that discharge wastewater to POTWs. After considering all of the technology options described in Section 8.1.2, as is the case for NSPS,

[69] EPA is proposing to exempt from new PSES copper standards for existing discharges of nonchemical metal cleaning wastes that are currently authorized. For these discharges, the regulation would not specify PSES.

[70] Preferred Option 4a would increase this threshold for purposes of discharges of pollutants in bottom ash transport water only, to 400 MW or less.

EPA is proposing to establish PSNS based on the technologies specified in Option 4. The proposed PSNS would:

- Establish standards for mercury, arsenic, selenium, and nitrate-nitrite in discharges of FGD wastewater;
- Maintain a “zero discharge” standard for all pollutants in fly ash transport water, and establish a zero discharge standard for bottom ash transport water and FGMC wastewater;
- Establish standards for mercury, arsenic, selenium, and TDS in discharges of gasification wastewater;
- Establish standards for copper in discharges of nonchemical metal cleaning wastes; and
- Establish standards for mercury and arsenic in discharges of leachate.

For the same reasons identified for NSPS in Section 8.1.4, EPA is proposing Option 4 as its preferred option because the technologies forming the basis for that option are available and demonstrated and will not pose a barrier to entry.[71] In addition, EPA has determined that these standards will prevent pass-through of pollutants from POTWs into receiving streams and also help control contamination of POTW sludge. EPA also considered the non-water quality environmental impacts associated with the preferred option and found them to be acceptable, as described in Section 14.

8.1.7 Consideration of Future FGD Installations on the Analyses for the ELG Rulemaking

As explained earlier, implementation of air pollution controls may create new wastewater streams at power plants. The analyses and the findings on economic achievability presented in this preamble reflect consideration of wastestreams generated by air pollution controls that will likely be in operation at plants at the time EPA takes final action on this rulemaking. However, EPA recognizes that some recently promulgated Clean Air Act requirements, along with state requirements or enforcement actions, may lead to additional air pollution controls (and resulting wastestreams) at existing plants beyond this date. In an effort to assess the economic achievability of the proposed rule in such cases, EPA also conducted a sensitivity analysis that forecasts future installations of air controls through 2020 and the associated costs of complying with the proposed regulatory requirements for the wastewater that may result from the forecasted air control installations.[72] The sensitivity analysis and results are described in more detail in the memorandum entitled, “Flue Gas Desulfurization Future Profile Sensitivity Analysis” [ERG, 2013a].

[71] For the same reasons discussed above in Section VIII for NSPS, EPA similarly determined the other regulatory options do not reflect PSNS.

[72] EPA considers that by forecasting future installations of controls out to the year 2020, the sensitivity analyses for this rulemaking reasonably reflect full implementation of air pollution controls to comply with existing federal and state requirements.

EPA has two primary data sources upon which to make its projections of future air control installations: 1) Integrated Planning Model estimates for the final MATS rule;[73] and 2) responses to EPA's steam electric industry survey. At the time EPA promulgated the MATS rule in 2011, it projected air pollution control retrofits using IPM (which also included projected retrofits for CSAPR). To support this rulemaking, EPA surveyed the industry about its plans for installing certain new air pollution controls at facilities through 2020. EPA has no reason to conclude that either the IPM FGD projections or the survey projections are more accurate than the other. In fact, both of these sources may overstate actual installations. Prior to MATS becoming final, many plant owners and operators assumed that wet scrubbers would be the only technology available to meet emissions limits for acid gases. As EPA gathered and published additional data on facility emission rates (which informed how the Agency set the standards), and as stakeholders researched and published additional information on the performance of less capital-intensive control technologies such as dry sorbent injection, it has become clear that many facilities will find it more cost-effective to forgo wet scrubbers in favor of other emission-reduction strategies. Furthermore, major economic variables such as electricity demand and natural gas prices have changed substantially since the prevailing market conditions in 2010, when respondents were answering the survey. For example, a facility originally indicating an expectation in the industry survey to install a wet scrubber by 2020 may now find itself no longer competitive in the updated marketplace with substantially lower natural gas prices and lower electricity demand growth than previously expected. Consequently, the facility may elect to retire and thereby neutralize the previously reported intent to scrub. Nevertheless, these two sources remain the best available information EPA has with which to estimate future conditions.

As a first step in conducting a sensitivity analysis, EPA compared the projections from the two sources described above. This comparison demonstrates that the IPM results for the MATS Policy Case and the ELG industry survey responses are consistent at the aggregate level. Furthermore, in very large part, both the survey and IPM identify the same generating units as being wet-scrubbed, either currently or in the future (the two sources are in agreement for approximately 94 percent of the wet-scrubbed units). The two sources also project similar wet-scrubbed capacities. In the very few cases where there are differences between the two sources, the differences are primarily due to the expected variation at a unit-level (e.g., IPM projects wet FGD at unit A and dry FGD at unit B, but instead the survey responses report wet FGD at unit B and dry FGD at unit A). Another difference between the MATS IPM estimates and the industry survey estimates is that, in a very few cases, the IPM results estimate that certain plants would retire (and therefore would not install wet scrubbers). In conducting the analyses for the ELG, EPA made the conservative assumption (i.e., one that would tend to overestimate cost, if anything) that a plant would still be in operation in 2020 unless the plant has formally announced its closure by 2014.

Because its goal in conducting this sensitivity analysis was to assess the economic achievability of the proposed ELG, even in light of possible future air controls, EPA developed a conservative upper bound estimate of future installations by combining the results of the two sources to develop its "future steam profile." In other words, EPA combined any source that reported or projected a wet FGD into one "future steam profile." This "future steam profile" is

[73] EPA IPM v.4.10 projections for units based on compliance with CSAPR, MATS, state rules, and enforcement actions including consent decrees.

conservative because it reflects more wet FGDs than are anticipated to actually be installed; that is, by aggregating the survey and IPM forecast estimates it results in a total number of wet FGD systems and wet-scrubbed capacity that is greater than either of those individual sources. EPA then added costs associated with projected wastewater discharges from this future steam profile to comply with the proposed ELGs to the total costs it previously calculated for the existing universe. Based on the results of this conservative analysis, EPA finds that discharges from these additional air controls (which, if actually installed, would be due to various requirements including state rules, consent decrees, CSAPR/CAIR, and MATS) may increase the costs of the proposed rule by no more than 10 to 15 percent. Even if all of these additional costs were to come to fruition, which is unlikely since the "future steam profile" overestimates the number of new wet FGD systems that are anticipated, EPA finds that these additional costs are economically achievable.

EPA notes that subsequent to its analysis, the D.C. Circuit Court of Appeals vacated the CSAPR. EPA will continue to assess the potential impacts that changes to air pollution regulations may have on future installations of wet FGD systems. For the purpose of FGD wastewater analyses for this rulemaking, EPA has made a conservative assumption that all of the previously projected wet scrubber additions in the CSAPR-inclusive baseline (which also included MATS, state rules, consent decrees, etc.) would continue to be built, and that discharges from those additional wet scrubbers would therefore be subject to the proposed revisions to the ELGs.

8.2 TIMING OF NEW REQUIREMENTS

As part of its consideration of technological availability and economic achievability, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at many existing facilities to meet the requirements of the rule. As discussed in Section 8.1.2, EPA proposes that certain BAT limitations for existing sources (those that would establish requirements more stringent than existing BPT requirements) would apply on a date determined by the permitting authority that is as soon as possible when the next permit is issued beginning July 1, 2017 (approximately three years from the effective date of this rule). This is true of the proposed limitations and standards based on any of the eight main regulatory options, including the preferred options, Option 3a, Option 3b, Option 3, or Option 4a.

EPA is proposing this approach for several practical reasons. While some facilities already have the necessary equipment and processes in place, or could do so relatively quickly, and may need little time before they are able to comply with the revised ELG requirements, not all will be able to do so. Some facilities will need time to raise the capital, plan and design the system, procure equipment, construct and then test the system. Moreover, providing a window of time will better enable facilities to install the pollution control technology during an otherwise planned shutdown or maintenance period. In some cases, a facility must apply for permission to enter into such a period where they are producing no or less power.

During site visits, EPA found that most facilities need several years to plan, design, contract, and install major system modifications, especially if they are to be accomplished during planned maintenance periods to avoid causing forced outages. EPA recognizes that the proposed rule would require a significant amount of system design by engineering firms, equipment procurement from vendors, and installation by trained labor forces. EPA anticipates that changes to FGD wastewater treatment systems, fly ash systems, bottom ash systems, and/or leachate treatment systems would constitute major system modifications requiring several years to accomplish for many plants. EPA identified certain technical and logistical issues at some facilities that may warrant additional time, such as coordinating ash system conversions for multiple generating units. In order to avoid any impacts on the consistency and reliability of power generation, outages at multiple facilities in one geographic area would need to be coordinated, which could also result in the need for more time.

EPA recognizes that permitting authorities have discretion with respect to when to reissue permits and can take into consideration the need to provide additional time to include BAT limits to prevent or minimize forced outages. Thus, in some cases, the new BAT requirements may as a practical matter be applied to a facility sometime after July 1, 2017. However, EPA judges that, under the proposed approach, all steam electric facilities will have the proposed BAT limitations applied to their permits no later than July 1, 2022, approximately 8 years from the date of promulgation of any final ELGs. For indirect discharges, except with respect to discharges of nonchemical metal cleaning waste, the proposed PSES requirements would apply by the date determined by the control authority that is as soon as possible beginning July 1, 2017, or approximately three years after promulgation of any final ELGs. EPA's record indicates it may not take that long for all facilities to meet the limitations and standards. Some plants may not require a major modification for one or more systems to be able to comply with new effluent limits and therefore would need less time. For example, some plants have installed dry fly ash handling systems that have capacity to handle all generated ash dry, yet they also maintain a wet ash handling system as a backup. The backup wet system is typically operated only a few days per year. According to the industry survey, plants such as these could quickly cease operation of the wet system, complying with a zero discharge requirement with relative ease.

EPA envisions that each facility subject to the proposed ELGs would study available technologies and operational measures, and subsequently install, incorporate and optimize the technology most appropriate for each site. EPA believes the proposed rule affords flexibility for a reasonable amount of time to conduct engineering studies, assess and select appropriate technologies, apply for necessary permits, complete construction, and optimize the technologies' performance. The permitting authority could establish any additional interim milestones, as appropriate, within these timelines.

8.3 References

1. Eastern Research Group (ERG). 2013a. Memorandum to the Record: Flue Gas Desulfurization Future Profile Sensitivity Analysis. (29 January). DCN SE01989.
2. Eastern Research Group (ERG). 2013b. Memorandum to the Steam Electric Rulemaking Record: Evaluation of Chemical Precipitation Costs for Ash Transport Water. (19 April). DCN SE03869.
3. Eastern Research Group (ERG). 2013c. Memorandum to the Steam Electric Rulemaking Record: Status of Biological Treatment Systems to Remove Selenium. (19 April). DCN SE03874.

4. Eastern Research Group (ERG). 2013d. Memorandum to the Rulemaking Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a. (19 April). DCN SE03834.
5. Electric Power Research Institute (EPRI). 2006. EPRI Technical Manual: Guidance for Assessing Wastewater Impacts of FGD Scrubbers. 1013313. Palo Alto, CA. (December). Available online at: http://www.epriweb.com/public/000000000001013313.pdf. Date accessed: 16 May 2008. DCN SE01817.
6. U.S. EPA. 2002. *Development Document for Final Effluent Limitations Guidelines and Standards for the Iron and Steel Manufacturing Point Source Category*. EPA-821-R-02-004. Washington, DC. (April).
7. U.S. EPA. 2003. *Development Document for the Final Effluent Limitations Guidelines and Standards for the Metal Products & Machinery Point Source Category*. EPA-821-B-03-001. Washington, DC. (February).
8. U.S. EPA. 1983. Development Document for Effluent Limitations Guidelines and Standards for the Metal Finishing Point Source Category. EPA-440/1-83/091. Washington, DC. (June).

SECTION 9
ENGINEERING COSTS

This section presents EPA's methodology to determine incremental capital and operating and maintenance (O&M) costs for the steam electric industry to comply with each regulatory option considered for the proposed rule.

Section 9 describes EPA's general approach for estimating incremental compliance costs for effluent limitations guidelines and standards (ELGs) for industrial categories. Section 9.2 provides a brief description of the basis for the compliance costs for each wastestream and technology option. Section 9.3 describes the methodology EPA used to estimate costs for the steam electric industry to achieve the limitations and standards based on each technology option considered (described in Section 8 of this report). Section 9.3 presents information on the specific cost elements included in EPA's methodology and the criteria EPA used to identify plants that would likely incur compliance costs. Section 9.4 describes the development of the data inputs, outputs, and model used to estimate the compliance costs. Section 9.5 presents EPA's methodologies for estimating those components of compliance costs that are applicable to more than one of the treatment technologies evaluated. Sections 9.6, 9.7, and 9.8 summarize the technology options costed and the results of the costs analyses for flue gas desulfurization (FGD) wastewater, fly ash and bottom ash transport water, and combustion residual landfill leachate, respectively.

9.1 INTRODUCTION

Effluent limitations guidelines and standards establish numerical limits on the discharge of pollutants to waters of the United States. These limits are based upon the performance of specific technologies that comprise the regulatory options. While implementation of the specific technologies that form the basis for the proposed regulatory options would not be required, EPA calculates the cost for plants to implement these technologies to estimate the compliance costs for the industry to meet the numerical limitations and standards, including any identified best management practices (BMPs). For existing sources, compliance costs are incremental, meaning they represent the costs expected to be incurred as a result of plants revising exiting operations to match those that form the bases of the regulatory options. For new sources, EPA estimates the costs to install such technologies compared to what a typical source would do in the absence of the rule.

EPA often estimates costs on a per plant basis and then sums or otherwise escalates the plant-specific values to represent industry-wide compliance costs. Calculating costs on a per plant basis allows EPA to account for differences in plant characteristics such as types of processes used, wastewaters generated and their flows/volumes and characteristics, and wastewater controls in place (e.g., best management practices and end-of-pipe treatment). EPA took this approach in estimating the compliance costs associated with the proposed rule.

EPA estimated the costs to steam electric power plants – whose primary business is electric power generation or related electric power services – of complying with the proposed ELGs. EPA evaluated the costs of the proposed ELGs on all plants currently subject to the existing ELGs.[74] Some aspects of the proposed ELGs (e.g., applicability changes) would likely not lead to increased costs to complying plants. Other aspects of the proposed ELGs would likely lead to increased costs to a subset of complying plants. These plants are generally those that generate the wastestreams for which EPA is proposing new limitations or standards. This section describes the detailed costing evaluation EPA performed for these plants that may incur compliance costs associated with the proposed rule.

As discussed earlier in Section 5, EPA proposes to establish a separate set of requirements for existing oil-fired generating units and units with a capacity of 50 MW or less. For these units, BAT limits would be set equal to BPT limits. As the proposed rule would not establish additional control on discharges associated with these operations, EPA accordingly did not include incremental costs for these units as a result of this proposed rule.[75]

EPA estimated compliance costs associated with each of the regulatory options from data collected through survey responses, site visits, sampling episodes, and from individual power plants and equipment vendors. EPA used this information to develop computerized cost models for each of the technologies that form the basis of the regulatory options. EPA used these models to calculate plant-specific compliance costs for all power plants that the information suggests would incur costs to comply with one or more proposed requirements associated with the regulatory options.[76] Therefore, EPA's plant-specific cost estimates represent the incremental costs for a plant when its existing practices would not lead to compliance with the option being evaluated. While implementation of the specific technologies that form the basis for the proposed regulatory options would not be required, EPA calculated the cost and for the plant to implement these technologies to estimate of the compliance costs associated with EPA’s proposal.

EPA’s cost estimates include the following key cost components: capital costs (one-time costs); annual operating and maintenance costs (which are incurred every year); and other one-time or recurring costs. Capital costs comprise the direct and indirect costs associated with the purchase, delivery, and installation of pollution control technologies. Capital cost elements are specific to the industry and commonly include purchased equipment and freight, equipment installation, buildings, site preparation, engineering costs, construction expenses, contractor’s fees, and contingency. Annual operating and maintenance costs comprise all costs related to operating and maintaining the pollution control technologies or performing BMPs for a period of one year. Operating and maintenance costs are also specific to the industry and commonly include costs associated with operating labor, maintenance labor, maintenance materials (routine replacement of equipment due to wear and tear), chemical purchase, energy requirements, residual disposal, and compliance monitoring. In some cases, the technology options may also

[74] Based on the Steam Electric Survey responses, Internet searches, articles, and data provided by the industry, EPA removed the following types of plants, or steam electric generating units, from the analysis as they were considered outside the applicability of the rule or would be by the time the final rule is promulgated: plants, or steam electric generating units, expected to be retired by 2014; and plants, or steam electric generating units, converting to non-fossil fuel sources (e.g., natural gas, municipal solid waste) by 2014.

[75] EPA did estimate costs for these operations to comply with the BAT limits applicable to the rest of the units and has included those estimates in the docket for the proposed rule.[U.S. EPA, 2012].

[76] Because the rule is scheduled for promulgation in May 2014, EPA did not include compliance costs or pollutant removals for plants that are expected to retire by 2014 and plants that do not discharge any of the applicable wastestreams.

result in recurring costs that are incurred less frequently than annually (e.g., 3-year recurring costs for equipment replacement) or one-time costs other than capital investment (e.g., one-time engineering costs).

9.2 STEAM ELECTRIC TECHNOLOGY OPTION COST BASES

The following subsections provide a brief description of the basis for the estimation of the compliance costs for each wastestream and technology option. The technology options considered as the bases of the regulatory options are identified in Section 8 and described in detail in Section 7.

9.2.1 FGD Wastewater

EPA estimated compliance costs for plants to treat FGD wastewater using one of the following three technology options:

- One-stage chemical precipitation;
- One-stage chemical precipitation followed by biological treatment; and
- One-stage chemical precipitation followed by softening and vapor-compression evaporation.

For the one-stage chemical precipitation system, EPA included costs for the plants to install and operate the following:

- Equalization tank to hold and store the wastewater;
- Reaction tanks for the addition of lime, organosulfide, ferric chloride, and polymers;
- Solids-contact clarifier to remove suspended solids;
- Gravity sand filter to reduce solids; and
- Effluent storage tank.

Additionally, EPA included costs for a sludge holding tank and filter presses to dewater the solids collected in the clarifier. EPA also included costs for the transport and disposal of the resulting solids in a landfill. The costs also include all ancillary equipment and the associated operating and maintenance costs associated with the system.

For the one-stage chemical precipitation followed by biological treatment system, EPA included all the costs described above for the chemical precipitation system, but it also included costs for the following:

- Anoxic/anaerobic biological treatment system (two stages); and
- Heat exchanger (for plants in certain geographic locations).

EPA also included costs for the transport and disposal of additional solids collected in the biological system. The costs include all ancillary equipment and the associated operating and maintenance costs associated with the system.

For the one-stage chemical precipitation followed by softening and vapor-compression evaporation, EPA included all the costs described above for the chemical precipitation system, but it also included costs for the following:

- Softening step, including clarification and solids dewatering;
- Reaction tank for acid addition;
- Heat exchanger to increase the temperature of the wastewater;
- Deaerator to remove noncondensibles;
- Mechanical vapor compression brine concentrator;
- Distillate tank; and
- Forced-circulation crystallizer.

EPA also included costs for the transport and disposal of additional solids collected in the softener and the forced-circulation crystallizer. The costs include all ancillary equipment and the associated operating and maintenance costs associated with the system.

9.2.2 Fly Ash Transport Water

EPA estimated compliance costs for plants operating wet sluicing systems to convert to dry vacuum fly ash handling systems. For each generating unit with a wet sluicing system, EPA determined that the plants would likely continue to use the existing valves and branch lines underneath the fly ash collection hoppers, but the plant would require new valves and piping to convey the ash to the silo(s). Additionally, EPA included costs for a mechanical exhauster to create the vacuum. EPA also included costs for the plant to install a new silo, including pugmills and wet unloading equipment. Finally, EPA included costs for the transport and disposal of all the additional ash that the plant is now handling with the dry vacuum system.

9.2.3 Bottom Ash Transport Water

EPA estimated compliance costs for plants operating wet sluicing systems to convert to bottom ash handling systems that eliminate the discharge of bottom ash transport water. For each generating unit with a wet sluicing system, EPA estimated the costs for converting to one of the following two systems:

- Mechanical drag system; and
- Remote mechanical drag system.

For the mechanical drag system, EPA included the costs for the demolition of the bottom of the boiler and installation of a mechanical drag system at the bottom of the boiler. The MDS design does not include operation as a closed-loop system (i.e., the water leaving the system with the bottom ash does not need to be collected, cooled, and returned to the system), thereby eliminating the need for a heat exchanger.[77] For the remote mechanical drag system, EPA included the costs for the construction of a remote mechanical drag system away from the boiler, as well as a sump, recycle pumps, and a chemical feed system to return the water to the boiler for reuse as bottom ash transport water.[78] EPA also included the costs for a semi-dry silo for both systems. Additionally, EPA included the costs for the transport and disposal of all bottom ash to a landfill.

For certain plants that recycle most of the bottom ash transport water within the system and only discharge a small amount of wastewater, EPA estimated costs for these plants to hire a consultant to help them cease discharging bottom ash transport water and operate a completely closed-loop system.

9.2.4 Combustion Residual Leachate

EPA estimated compliance costs for plants generating combustion residual leachate from landfills or surface impoundments to comply with requirements based on one of the following two technology options:

- One-stage chemical precipitation; and
- One-stage chemical precipitation followed by biological treatment.

To estimate the compliance costs for plants that generate landfill leachate, EPA used the same general methodology described in Section 9.2.1.

Plants that generate surface impoundment leachate will likely use a different approach than installing the technology basis to comply with limitations or standards based on either of the technology options. As described in Section 7.4, 36 percent of plants generating leachate from combustion residual impoundments recycle the leachate back to the ash/FGD impoundment from which it was collected. Additionally, some plants use the impoundment leachate for dust control at a landfill or to moisture condition ash transported to a landfill. Based on these data, EPA believes that when faced with the proposed effluent limitations for discharges of combustion residual leachate, plants would comply with the limit by recycling the leachate back to the ash/FGD impoundment from which it was generated (or use the leachate for dust control/moisture conditioning) instead of installing the technology option to treat and discharge the wastewater because it is a less expensive alternative. There would be no (or negligible) costs associated with recycling the leachate back to the ash/FGD impoundment because the plant will either: 1) use the existing pump that transfers the leachate to a separate location to pump it back to the impoundment; or 2) install a pump to transfer the leachate to the impoundment, but the costs would be offset because the plant no longer needs to operate a separate impoundment (or other treatment system) that is currently used to treat the leachate to meet the existing BPT

[77] Because the MDS system does not use water as the transport mechanism, the water removed from the system with the bottom ash is not bottom ash transport water, and therefore, is not subject to the bottom ash transport water effluent limitations.

[78] Because the remote MDS system does use water as the transport mechanism, all water removed from the system must be reused without discharge to meet the proposed zero discharge effluent limitations for bottom ash transport water.

effluent limitations prior to its discharge. Therefore, there are no compliance costs for combustion residual leachate from surface impoundments. Therefore, where this section further addresses the costing methodology for combustion residual leachate, it refers to the costs associated with the treatment of combustion residual leachate from landfills.

9.2.5 Gasification Wastewater

As described in Section 4.2.3, there are two currently operating and one planned integrated gasification combined-cycle (IGCC) units in the United States. Each of these three plants is operating or will operate the vapor-compression evaporation system that is the technology basis for the proposed ELGs for gasification wastewater. Therefore, because all the plants are currently operating the BAT system, there are no compliance costs for gasification wastewater.

9.2.6 Flue Gas Mercury Control Wastewater

As described in Section 6.4, there are approximately 73 plants with at least one activated carbon injection (ACI) system. Of these, only six (three with current systems and three with planned systems) reported handling the flue gas mercury control (FGMC) waste using a wet sluicing system. However, of these six plants, only one discharges FGMC wastewater, and that one plant collects the FGMC waste with the fly ash in the primary particulate control system and already has the capability to handle both the FGMC and fly ash dry. Therefore, there are no compliance costs for flue gas mercury control wastewater.

9.2.7 Nonchemical Metal Cleaning Wastes

As described in Section 8.1.3, EPA is proposing to set BAT limitations for nonchemical metal cleaning wastes that are equivalent to the BPT standards that are already in place for this wastestream. Because nonchemical metal cleaning wastes are already subject to the proposed BAT limitations, based on the current BPT standard, the plants generating and discharging nonchemical metal cleaning wastes should already be meeting these standards. Additionally, as described in Section 8.1.3, EPA is proposing to exempt from new limitations and standards any nonchemical metal cleaning wastes generated and authorized for discharge without copper and iron limits. As a result, all facilities are either already in compliance or will be exempt from the requirements and, therefore, EPA finds there are no compliance costs for nonchemical metal cleaning wastes.

9.3 STEAM ELECTRIC COMPLIANCE COST METHODOLOGY

EPA developed a cost methodology to estimate plant-level compliance costs for existing and new sources using data collected from the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey), site visits, and sampling episodes. EPA also solicited data from vendors of various wastewater treatment technologies and ash handling operations to estimate plant-level compliance costs. The estimated costs are incremental costs to account for only the additional costs beyond those the plant already incurs, or would incur as a new source, in order to comply with the proposed regulations.

As a first step in estimating costs associated with new or additional limitations or standards for discharges from a particular generating unit at an existing steam electric plant (i.e., existing sources), EPA used the plant's survey response to determine if the wastestreams it discharges may be subject to new requirements under a regulatory option. Then, for each of the wastestreams that may be subject to new requirements for a regulatory option, EPA reviewed the survey response, available sampling data, and industry long-term self-monitoring data for the plant to determine if its existing practices would lead to compliance with the new or revised limitations or standards (e.g. plant currently employs the technology option). In this case, EPA finds the plant will incur no compliance cost associated with the discharge of that particular wastestream other than compliance monitoring costs. For all other applicable wastestreams, EPA assessed the operations and treatment system components in place at the plant, identified necessary components that the plant would need to come into compliance, and estimated the cost to install and operate those components. As appropriate, EPA also accounted for expected reductions in the plant's costs associated with their current operations or treatment systems that would no longer be needed as a result of installing and operating the technology bases (e.g., avoided costs to manage surface impoundments). For plants that may already have certain components installed, EPA compared certain key operating characteristics, such as chemical addition rates, to determine if additional costs (e.g., chemical costs) were warranted.

For example, to comply with Option 3, EPA estimated compliance costs for a plant that currently sluices fly ash to an ash impoundment and subsequently discharges that fly ash transport water. In this case, EPA estimated the cost for the plant to convert its fly ash handling system to a dry vacuum system and determined that certain components of its existing system would continue to be used following the conversion.[79] EPA also included costs for additional equipment, such as vacuum systems and silos, to handle and store the dry fly ash. EPA also included additional transportation and landfill disposal costs, and cost savings for managing less waste through the ash impoundment(s).

As another example, to comply with Option 3, EPA estimated compliance costs for a plant that currently treats its FGD wastewater through a chemical precipitation system prior to discharge. In this case, EPA evaluated 1) whether the chemical precipitation system design basis includes equalization with 24-hour residence time, 2) if the plant had an equivalent number and/or type of reaction tanks, and 3) if the plant already had components such as chemical feed systems, solids contact clarifier, sand filter, effluent and sludge holding tanks, sludge filter presses, and pumps in place. If the plant had any of these components in place, EPA did not include that cost in its compliance cost estimate. EPA also evaluated whether chemical addition costs would be required based on the plant's reported chemical addition and dosages, and estimated the costs for installing and operating the biological treatment stage.

EPA also evaluated the additional transportation and landfill operations required to dispose of the additional solid waste generated (FGD sludge, fly ash, bottom ash) from the implementation of the technology options. EPA estimated disposal costs based on whether the plant reported an on-site combustion residual landfill.

[79] The conversion from wet to dry fly ash handling for a unit requires new equipment to pneumatically convey the ash; however, ash handling vendors stated that for dry vacuum retrofits, the existing hopper equipment and branch lines can be retained and reused.

For each plant, EPA calculated compliance costs for all applicable technology options and then calculated the total costs for the eight regulatory options, presented in Section 8.1 of this report. For more information on the compliance cost methodology, see EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [U.S. EPA, 2013].

9.4 STEAM ELECTRIC COST MODEL

EPA calculated the industry incremental compliance cost estimates by developing a computer-based cost model containing the following main components:

- Input Data
- Industry Assumptions/Factors
- Technology Cost Modules
- Model Outputs

Input data include relevant plant-specific information, such as identification of which wastewaters are discharged from each plant, together with plant characteristics such as plant processes, wastewater flow rates, production data, and existing pollution control technologies. Industry assumptions and factors are general values and factors that are not plant-specific and are applicable to the entire industry. These include constants and coefficients used in the cost calculations such as equipment design basis (used for equipment sizing, for example hydraulic residence time), materials of construction, equipment capacity (accounts for maximum design capacity as compared to typical operating conditions), equipment redundancy, transport distance for equipment and supplies, transport mode and capacity, and cost indices (used to adjust cost data from different years to a common base year). Technology cost modules use the plant-specific input data and industry assumptions/factors to calculate and output costs for a specific cost component (technology or technology component) for each applicable wastestream for each plant and each regulatory option. Finally, reporting programs combine the applicable cost components to calculate plant-level capital and operating and maintenance costs (and any necessary one-time and/or recurring costs) for each regulatory option, and to sum or otherwise escalate these plant-level costs to calculate total industry capital and operating costs by regulatory option.

EPA used this computer-based cost model approach, including all four main components described above, to generate plant-specific compliance costs. The steam electric cost model calculates compliance costs by referencing several input tables and running the applicable technology cost modules specific to each plant's input characteristics. The compliance costs for each technology option are calculated using a combination of the technology cost modules, some that calculate option costs specific to each technology option (e.g., biological treatment, dry fly ash handling) and some that calculate common cost elements for each technology option, although the inputs may differ based on specific wastestreams (e.g., transport and disposal costs). Table 9-1 presents the different technology cost modules that compose the technology options. Each technology option incorporates technology-specific and global assumptions and factors to calculate the compliance costs (e.g., the model outputs).

Table 9-1. Technology Costs Modules Used to Estimate Compliance Costs

Technology Option	Technology Cost Module							
	One-stage Chemical Precipitation	Biological Treatment	Vapor-Compression Evaporation	Dry Fly Ash Handling	Dry Bottom Ash Handling[a]	Transportation	Disposal	Impoundment Operation Costs
FGD Wastewater Treatment: Chemical Precipitation	✓					✓	✓	✓
FGD Wastewater Treatment: Chemical Precipitation + Biological Treatment	✓	✓				✓	✓	✓
FGD Wastewater Treatment: Chemical Precipitation + Evaporation	✓		✓			✓	✓	✓
Fly Ash: Zero discharge				✓		✓	✓	✓
Bottom Ash: Zero discharge					✓	✓	✓	✓
Leachate Wastewater Treatment: Chemical Precipitation	✓					✓	✓	
Leachate Wastewater Treatment: Chemical Precipitation + Biological Treatment	✓	✓				✓	✓	

Note: As described in Sections 9.2.5 and 9.2.6, EPA did not estimate costs for gasification wastewater, flue gas mercury control wastewater, or nonchemical metal cleaning wastes.

a – The technology cost module is called the "Dry Bottom Ash Handling" module, but it includes a technology option that is a closed-loop recycle system.

9.4.1 Input Data to Technology Cost Modules

EPA developed a set of input tables based on information from the Steam Electric Survey, site visits, and sampling episodes. The cost model references the input tables to estimate the appropriate compliance cost for each plant for each technology option. The cost model estimates compliance costs at a plant basis for each technology option and then sums the various technology option to estimate the plant-level compliance costs for each regulatory option. The cost model first references a plant-level input table, which indicates the technology options specific to each plant. The plant-level cost input table was developed using data from the Steam Electric Technical Questionnaire Database (survey technical database), which was developed using the plant responses to the Steam Electric Survey to identify the population of plants that discharge wastestreams that may be subject to new or additional limitations or standards [ERG, 2013d]. For all plants that generate at least one of these wastestreams, EPA determined if the plant discharges (or may discharge by 2014) one or more of the applicable wastestreams (e.g., FGD wastewater, fly ash transport water) controlled by a regulatory option. If the plant does not discharge an applicable wastestream, then EPA set the compliance costs for that wastestream to be zero. If the plant does discharge an applicable wastestream, then EPA gathered the plant-specific data appropriate for the applicable technology cost modules. Table 9-2 identifies the number of plants that EPA finds will likely incur costs to comply with new or additional limitations or standards for a wastestream under at least one of the evaluated regulatory options.

Table 9-2. Number of Plants Expected to Incur Compliance Costs by Wastestream and Regulatory Option

Regulatory Option	FGD Wastewater	Fly Ash Transport Water	Bottom Ash Transport Water	Combustion Residual Leachate	Gasification Wastewater	Flue Gas Mercury Control Wastewater	Nonchemical Metal Cleaning Wastes	Total[a]
1	116	0	0	0	0	0	0	116
3a	0	66	0	0	0	0	0	66
2	116	0	0	0	0	0	0	116
3b	17	66	0	0	0	0	0	80
3	116	66	0	0	0	0	0	155
4a	116	66	115	0	0	0	0	200
4	116	66	240	101	0	0	0	277
5	116	66	240	101	0	0	0	277

a – The number of plants incurring costs is not additive for each regulatory option because some plants may incur costs for multiple wastestreams.

Each technology cost module includes a set of input tables. These input tables include indicators specifying the level of costs required for each technology option and the plant-specific data used in the cost equations. The following subsections describe each of the input tables used in the technology cost modules. See the appendix of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the specific input tables described below [U.S. EPA, 2013].

FGD Wastewater Flow

For each applicable plant, EPA identified a plant-level FGD wastewater flow rate in gallons per day. EPA used the purge rate reported in the Steam Electric Survey as the input value for the FGD technology cost modules. For plants operating more than one FGD system, the input value was the sum of the purge rates for the individual systems. For current FGD systems that did not provide an FGD purge flow value, EPA estimated the purge rate based on the amount of coal burned and the median FGD purge rate per ton of coal burned based on coal type. See Section 4.1.1 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the FGD wastewater flow rate estimation methodology [U.S. EPA, 2013].

FGD Treatment-In-Place Data

This input table includes data on each plant's current level of treatment for its FGD wastewater. For plants currently treating the FGD wastewater using one-stage chemical precipitation, anoxic/anaerobic biological treatment, or vapor-compression evaporation systems, EPA did not estimate compliance costs for the specific pieces of equipment that are already operating at the plant. For example, under Option 1, if a plant operates a one-stage chemical precipitation system for the treatment of FGD wastewater that includes all the steps included as the basis for the technology option other than sulfide precipitation, then EPA would include capital costs for the plant to install a reaction tank and sulfide chemical feed system and operating and maintenance costs for the amount of sulfide added to the system on a yearly basis. The compliance costs for all other pieces of equipment for the system would be set to zero.

Fly Ash Production Data

For each applicable generating unit, EPA identified generating unit-level wet fly ash production in tons per day and operating days per year. EPA used these values reported in the Steam Electric Survey as input values for the fly ash technology cost module. Because the cost model estimates fly ash compliance cost at the generating unit level, EPA used unit-level input values.

EPA also identified generating units with existing dry fly ash handling equipment. Steam electric generating units equipped with only wet fly ash handling systems would incur the costs for complete conversion of the ash handling system. Those generating units equipped with both wet and dry fly ash handling capabilities may need only certain additional equipment in order for them to handle all fly ash dry (i.e., additional vacuum capacity, additional silo capacity, additional unloading equipment). EPA evaluated each plant and unit to identify the additional equipment that would be needed and included costs for only those pieces of equipment.

Bottom Ash Production Data

For each applicable generating unit, EPA identified generating unit-level wet bottom ash production in tons per day, operating days per year, and capacity in megawatt (MW). EPA used these values reported in the Steam Electric Survey as input values for the bottom ash technology cost module. Because the cost model estimates bottom ash compliance cost at the generating unit level, EPA used unit-level input values.

Impoundment Data

EPA used data from the Steam Electric Survey and plant contacts to identify which plants operate one or more impoundments containing combustion residuals including FGD solids, fly ash, and/or bottom ash.

On-Site Landfill Data

EPA used data from the Steam Electric Survey to identify which plants operate on-site active/inactive landfills containing combustion residuals including FGD solids, fly ash, and/or bottom ash.

Landfill and Leachate Data

For each landfill identified as generating landfill leachate, EPA identified the landfill leachate volume discharged each year in gallons per day. For those plants that did not report a leachate volume in the Steam Electric Survey, EPA estimated a flow using data from other plants that reported a leachate volume in the survey. EPA first determined a median leachate discharge rate per acre of landfill containing combustion residuals, based on the plant responses to the Steam Electric Survey, and multiplied this value by a plant's reported combustion residual landfill acreage collecting leachate to estimate a flow. For those plants that didn't report a leachate volume or a landfill acreage collecting leachate, EPA estimated the landfill acreage collecting leachate based on the plant's reported total active/inactive landfill acreage and the median ratio of landfill acreage collecting leachate to total active/inactive landfill acreage for those plants that provided both values. Finally, for those plants EPA could not estimate a value using the other two approaches, EPA estimated the leachate volume using the median leachate volume for all plants reporting a volume.

See Section 4.1.3 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the landfill leachate flow rate estimation methodology [U.S. EPA, 2013].

9.4.2 Industry Assumptions/Factors

The steam electric cost model includes several data tables containing values for industry assumptions and factors. These assumptions and factors are used in the cost equations for the specific technology options for all plants incurring costs for the specific technology option.

Each technology cost module contains a set of tables including the specific factors for that technology option. These factors include the coefficients for the technology option equations and other input constants applicable to all plants incurring the specific technology option costs. For example, for the fly ash cost methodology, EPA used a dry fly ash density of 45 lbs./ft^3, which is used to estimate the size of the silo(s) required to store the ash. EPA used this density for all generating units for which the fly ash compliance costs are applicable. For more information on the specific technology cost module factors, see EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report. [U.S. EPA, 2013]

Although each technology cost module contains its own set of factor tables, there are two sets of industry factors referenced by all technology option modules. These coefficients and constants do not change based on the different elements of the technology cost modules. These industry factors include:

- **Cost Indices**. Because EPA presents all compliance costs in 2010 dollars, EPA had to index several cost components. EPA adjusted all costs to 2010 dollars using the RS Means Historical Cost Index values for all technology cost modules [RSMeans, 2011]
- **Freight Cost Factors.** For all technology options, EPA estimates several freight costs for shipping equipment or materials to the plant. The factors used to estimate these shipping costs are universal for all technology options. These values were estimated using data from FreightCenter.com and vendor contacts. [U.S. EPA, 2013].

9.4.3 Technology Cost Modules

To estimate the plant-level technology option compliance costs, EPA developed nine different technology cost modules that use the various input data, industry assumptions and factors, and costing methodologies to generate plant-specific compliance cost outputs. Each technology cost module calculates specific cost components for each plant incurring compliance costs. The technology cost modules and a brief description of the cost components calculated are included in the following listing. See Sections 9.4 and 9.5 for more specific information on the technology cost modules.

- Biological Treatment – calculates capital and O&M costs associated with an anoxic/anaerobic biological treatment system;
- One-Stage Chemical Precipitation – calculates capital and O&M costs associated with the one-stage chemical precipitation system used as the basis for the technology option;
- Vapor-Compression Evaporation – calculates capital and O&M costs associated with the vapor-compression evaporation system used as the basis for the technology option;
- Dry Fly Ash Handling – calculates capital, O&M, and recurring costs associated with the dry fly ash handling system used as the basis for the technology option;
- Dry Bottom Ash Handling – calculates capital, O&M, one-time, and recurring costs associated with a dry or closed-loop recycle bottom ash handling systems used as the basis for the technology option;
- Transportation – calculates O&M costs associated with transporting FGD solid waste, ash, and/or landfill leachate solid waste to an on- or off-site landfill;
- Disposal – calculates capital and O&M costs associated with disposing of FGD, ash, and/or landfill leachate solid waste in an on- or off-site landfill;

- Impoundment Operation – calculates O&M and recurring costs associated with operating and maintaining an on-site impoundment; and
- Impoundment BMP Costs – calculates the annualized costs associated with BMP for combustion residual impoundments.

EPA calculates each technology option cost by summing the costs estimated by the applicable individual technology cost module (e.g., biological treatment or bottom ash handling) and the technology cost modules that calculate transportation, disposal, and impoundment costs. For each technology option, the cost model sums the costs associated with the technology cost modules that compose each option, as shown in Table 9-1. The cost model combines the cost components and calculates total capital, total O&M, one-time and recurring costs for each technology option.

As explained in Section 8.1.2, EPA is also considering BMPs as part of all of the regulatory options evaluated for the proposed ELGs. In order to better inform this consideration, EPA also calculated costs associated with BMPs. EPA only calculated BMP costs for impoundments that are expected to continue receiving combustion residual wastewater after the implementation of the ELGs. Therefore, the determination of which impoundments will incur BMP costs must be based on the entire regulatory option (e.g., Option 3), and not just at the technology option (e.g., fly ash transport water) because EPA can only determine if an impoundment will stay open or stop receiving combustion residual waste when assessing all the wastes. For example, if an impoundment receives FGD wastewater and fly ash transport water, the impoundment would stay open (i.e., continue to operate) under Option 1 because fly ash transport water would still be sent to the impoundment, but the impoundment would stop receiving combustion residual wastewater under Option 3. As shown in this example, the impoundment BMP costs cannot be determined only based on the technology options, but must be determined based on the regulatory option. Therefore, EPA did not include the impoundment BMP cost module in Table 9-1. See Section 9.5.5 for additional information on EPA’s approach for estimating costs associated with BMPs.

9.4.4 Model Outputs

The cost model output is a plant-level summary of the incremental technology option costs. The output reflects each plant incurring a cost for an evaluated wastestream. EPA presents the incremental costs on two levels: at the cost-component level and at the total plant level. The total plant costs include total capital, total O&M, total three-year recurring costs, total five-year recurring costs, total 6-year recurring costs, total 10-year recurring costs, and total one-time costs incurred by the plant. The cost-component level shows a breakdown of the individual cost components for each of the technology costs. The cost-component level includes individual capital costs (e.g. equipment, installation, land, and engineering) and individual O&M costs (e.g. labor, materials, energy, effluent monitoring, and chemicals). See Sections 9.6.4, 9.7.3, and 9.8 for the cost model outputs for each technology.

9.5 COSTS APPLICABLE TO ALL WASTESTREAMS

EPA developed several methodologies to calculate compliance costs applicable to more than one technology option. Using this approach, EPA could use the same methodology for each technology option without duplicating the calculations in the cost model. For example, the cost methodology for disposing combustion residual solid waste to a landfill is the same for each type of waste; however, the input values and factors (i.e., type, amount, and density of waste) vary depending on the technology option (FGD, fly ash, or bottom ash). The following subsections present the methodology used to estimate costs for compliance monitoring, transportation, disposal, impoundment operations, and impoundment BMPs.

9.5.1 Compliance Monitoring Costs

Where a regulatory option would establish requirements for pollutants not currently regulated in the existing ELGs, EPA calculated plant-level compliance monitoring costs for plants to sample and analyze their discharges to assess their compliance with the proposed effluent limitations. Compliance monitoring costs are annual O&M costs calculated by summing the components shown in the equation below.

Compliance Monitoring Costs = Sampling Labor Costs + Sampling Materials Costs + Sample Shipping Costs + Sample Analysis Costs

Sampling labor costs are the costs associated with plant personnel collecting and analyzing wastewater samples. EPA calculated sample labor costs using a labor rate and the total number of labor hours required per year. EPA assumed samples would be collected and analyzed weekly for NPDES compliance monitoring. EPA used data from the Steam Electric Survey and the U.S. Bureau of Labor Statistics to estimate the labor rate for the sampling team and environmental engineer required to collect and analyze the samples.

Sampling material and supply costs are the costs associated with the materials and supplies, such as personal protective equipment, sampling containers, and other supplies, required to collect and analyze samples. EPA calculated material and supply costs using the cost of the materials and supplies per sampling events and the number of sampling events per year. EPA based the sampling material costs on the costs the Agency incurred for individual items during its field sampling program. EPA multiplied the item costs by the number of items that would be required over the course of a year and then summed the costs for all the individual items.

EPA estimated the costs for shipping the samples to laboratories using the cost of a sample shipment and the total number of sample shipments per year. EPA assumed that samples would be sent to two different laboratories, one for analysis of low-level mercury and one for analysis of other metals. EPA assumed that one of the laboratories would be able to analyze the samples for total dissolved solids and nitrate/nitrite.

EPA calculated sample analysis costs using the cost of analyzing each sample that would be collected per sampling event and the number of sampling events per year. EPA based the sample analysis costs on the costs the Agency incurred during its field sampling program. See Section 5.2 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source*

Category report for more details on the compliance monitoring cost methodology [U.S. EPA, 2013].

9.5.2 Transportation Costs

Steam electric power plants can reuse, market/sell, or give away combustion residuals. Alternatively, plants can transport combustion residuals to a disposal site (e.g., landfill). For the proposed ELGs, EPA conservatively included costs for plants to transport all solid waste to a landfill because not all plants have the means to market/sell or give away the combustion residuals.

All combustion residuals can be transported to on-site or off-site landfills in an open dump truck. For plants with existing on-site landfills already containing combustion residuals, EPA included costs for these plants to dispose of any additional combustion residuals resulting from compliance with the ELGs in an on-site landfill, by either expanding the existing landfill or building a new landfill to accommodate the additional waste. For plants that do not have existing on-site landfills (or have only on-site landfills that do not contain combustion residuals), EPA included costs for these plants to dispose of the additional combustion residuals in an off-site non-hazardous landfill.

As described in Section 9.4.1, EPA used data from the Steam Electric Survey to identify which plants have existing landfills containing combustion residuals. EPA estimated costs for on-site transportation of ash and FGD solids for all plants with at least one open landfill containing combustion residuals. EPA estimated off-site trasnportation costs for ash and FGD solids for all other plants (i.e., those without an open landfill containing fuel combustion residuals).

EPA based plant-level costs for transportation of combustion residuals on the total amount of waste generated at each plant. For each wastestream, EPA calculated the amount of solid waste generated using methodologies presented, by technology option, in Sections 9.6, 9.7, and 9.8.

EPA estimated transportation costs for plants with an on-site landfill using the estimated amount of solid waste and an on-site specific unitized cost value, in dollar per ton, based on information provided by ORCR for the coal combustion residuals (CCR) rule, developed using the Remedial Action Cost Engineering Requirements (RACER 2010) software version 10.4. EPA estimated transportation costs for plants with an off-site landfill using the estimated amount of solid waste and an off-site specific unitized cost value, in dollar per ton, provided by ORCR based on the RACER 2010 model. For each plant and wastestream, EPA summed the total tonnage of combustion residuals and multiplied it by the appropriate transportation cost to estimate a plant-specific transportation cost. See Section 5.3 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the on- and off-site transportation cost methodologies [U.S. EPA, 2013].

9.5.3 Disposal Costs

EPA conservatively determined costs for plants to dispose of all combustion residual landfills to on-site or off-site landfills. To the extent plants are able to market/sell these residuals, EPA has over costed disposal and has not accounted for revenue associated with other options. As previously discussed in Section 9.5.2, EPA used data from the Steam Electric Survey to identify which plants have existing landfills containing combustion residuals. EPA estimated costs for on-site disposal of ash and FGD solids for all plants with at least one open landfill containing combustion residuals. EPA compliance costs estimate the costs for the plant to expand the landfill to handle the additional combustion residuals that will need to be stored in the landfill to comply with the ELGs. EPA estimated off-site diposal costs for ash and FGD solids for all other plants (i.e., those without an open landfill containing combustion residuals).

EPA based plant-level costs for disposal of combustion residuals on the total amount of waste generated at each plant. For each wastestream, EPA calculated the amount of solid waste generated using methodologies presented, by technology option, in Sections 9.6, 9.7, and 9.8.

EPA estimated capital and O&M disposal costs for an on-site landfill. Capital costs include the construction of the landfill, liner, additional groundwater monitoring, leachate collection system, and closures associated with the expansion of an existing landfill. EPA used a unitized cost value (in dollar per ton), that represents that capital cost components for an onsite landfill, and the estimated amount of solid waste produced from the implementation of technology options. EPA used a similar unitized cost approach to estimate the O&M costs based on the estimated amount of additional solid waste produced and a unitized cost value (in dollar per ton), that represents the costs associated with operating the landfill.

EPA estimated off-site disposal costs using a unitized cost (in dollar per ton) and the estimated amount of additional solid waste transported off-site. The unitized cost value represents the fee off-site landfills generally charge prior to accepting waste, known as the tipping fee. EPA estimated the tipping fees using state-level tipping fees and data provided in the Steam Electric Survey. See Section 5.4 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the on- and off-site disposal cost methodologies [U.S. EPA, 2013].

9.5.4 Impoundment Operation Costs

Implementation of the technology options will reduce, and in some cases eliminate, FGD wastewater, ash transport water, and combustion residuals managed in on-site impoundments. EPA therefore expects plants will experience cost savings in operating these impoundments. To calculate the incremental compliance cost of the technology option, EPA estimated the annual O&M and recurring costs associated with managing these wastewaters and combustion residuals in on-site impoundments. For each technology option evaluated, EPA estimated the amount of wastewater or combustion residual no longer expected to be managed in on-site impoundments and the associated cost savings. EPA estimated O&M and 10-year recurring costs associated with impoundment operations using the equations provided below. See Section 5.5 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and*

Standards for the Steam Electric Power Generating Point Source Category report for more details on the impoundment operation cost methodology [U.S. EPA, 2013].

Total O&M Costs = (-1) × (Impoundment O&M Costs + Earthmoving O&M Costs) × (Capacity Factor)

Impoundment O&M costs are the costs associated with the operation of the transportation system (i.e., pipelines, vacuum source), impoundment site, wastewater treatment system, and water recycle system at the impoundment. EPA calculated impoundment O&M costs using a unitized cost value ($7.35/ton), representing the impoundment O&M costs only, and the estimated amount of wet combustion residual waste generated (FGD solids, fly ash, and bottom ash).

Earthmoving O&M costs are the costs associated with the operation of earthmoving equipment (i.e., backhoe) required for sorting/stacking fuel combustion residual materials at the impoundment site. EPA calculated the impoundment O&M costs using a unitized cost value ($2.49/ton), representing the O&M only associated with the operation of the earthmoving equipment, and the estimated amount of wet combustion residual waste generated.

Additionally, EPA applied a capacity factor to adjust both unitized cost values for impoundment and earthmoving O&M costs based on the size of plant (in MW). EPA applied this factor to account for the economics of scale, the concept that larger plants, which will generally operate larger impoundments, incur smaller costs per ton of wet combustion residual [U.S. EPA, 1985].

Total 10-Year Recurring Costs = (-1) × (Cost of Earth Moving Vehicle)

EPA calculated 10-year recurring costs associated with operating the earthmoving equipment (i.e., backhoe). EPA calculated the total 10-year recurring costs by determining the cost and average expected life of a backhoe. EPA determined that the expected life of a backhoe is 10 years and that each plant will operate one backhoe.

9.5.5 Impoundment BMP Costs

Although implementation of the technology options will reduce, and in some cases eliminate, FGD wastewater, ash transport water, and combustion residuals managed in on-site impoundments, some impoundments may remain open. As explained in Section 8.1.2, EPA is considering BMPs as part of all of the regulatory options evaluated for the proposed ELGs. In order to better inform this consideration, EPA calculated costs associated with BMPs. EPA estimated BMP costs for the impoundments that are expected to continue operating after complying with the ELGs. See Section 5.6 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for more details on the impoundment BMP cost methodology [U.S. EPA, 2013]. The BMPs include remedial actions (e.g., slope repairs, drawing down water levels, controlling vegetation) and increases in inspection frequency from 17 times annually to 52 times annually. These management practices will help prevent future impoundment failures that have the potential to devastate the surrounding communities.

In order to estimate costs associated with these BMPs, which may be beyond the current state requirements, EPA reviewed the combustion residual impoundments at plants incurring compliance costs for FGD wastewater, fly ash transport wastewater, and/or bottom ash transport wastewater. For purposes of estimating BMP costs, EPA made some assumptions regarding the continued use of existing impoundments. Because these impoundments can contain multiple combustion residual waste, the probability that the impoundment will remain open depends on the regulatory option. For example, if an impoundment contains FGD waste and bottom ash, the impoundment would remain open based on the proposed Regulatory Option 3, which only affects FGD and fly ash transport wastewaters. EPA would expect the probability that a plant may elect to close the impoundment to be high based on the proposed Regulatory Option 4, which affects all wastestreams of interest. Therefore, EPA estimated impoundment BMP costs for this impoundment based on Regulatory Option 3; however, EPA estimated zero costs based on Regulatory Option 4.

EPA estimated an annualized cost for each impoundment determined to remain open, based on regulatory option. For each of these impoundments, EPA estimated that the remedial actions will require $10,000 annually per impoundment. EPA estimated the costs for the additional inspections based on information contained in Exhibit 3K of the *Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry* [ORCR, 2010]. EPA used the information regarding the labor hours and labor rate for recording keeping and weekly inspections to estimate the costs of the additional inspections. Based on this information, EPA estimated that the additional inspections will cost approximately $3,000 annually. Therefore, the total annual cost per impoundment is approximately $13,000.

9.6 FGD WASTEWATER

EPA estimated capital, O&M, 6-, and 10-year recurring costs associated with installing three technology options for FGD wastewater:

- One-Stage Chemical Precipitation;
- One-Stage Chemical Precipitation followed by Biological Treatment; and
- One-Stage Chemical Precipitation followed by Vapor-Compression Evaporation.

EPA estimated the chemical precipitation, biological treatment, and vapor-compression evaporation system costs separately, and then summed the costs generated by the appropriate technology cost modules to achieve the total technology option costs (i.e., the chemical precipitation costs were added to the biological treatment and vapor-compression evaporation costs to calculate the total costs for the technology option.

9.6.1 Chemical Precipitation

Section 7.1.2 describes the one-stage chemical precipitation system that forms the basis for this technology option. Additionally, Section 9.2.1 provides a brief summary of the technology basis for the chemical precipitation system. EPA estimated the costs to install and operate a one-stage chemical precipitation technology to treat FGD wastewater, specifically developed to remove mercury and arsenic (and other heavy metals). See Section 6.1 of the *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the FGD chemical precipitation cost methodology [U.S. EPA, 2013].Based on site visits, untreated FGD wastewater can contain elevated mercury concentrations based on a variety of different plant operating characteristics. To ensure that the mercury concentrations in the effluent discharged from the chemical precipitation system meet the proposed ELGs, EPA included costs for a mercury analyzer and extra equipment to analyze mercury in the discharge and recycle the chemical precipitation discharge for further treatment if necessary. The use of this equipment will allow plants to test the mercury in the effluent daily to ensure compliance with the ELGs. If the wastewater is not in compliance, the plant can recycle the treated water back to the equalization tank and adjust the system (i.e., add additional chemicals) to further treat the wastewater to meet the proposed ELGs. See Section 7 of this document for additional details.

As noted in Section 9.4.1, EPA evaluated plant responses to the Steam Electric Survey to determine whether chemical precipitation technologies are currently in place to treat FGD wastewater. As appropriate, plants operating these technologies were given credit for having treatment in place. EPA gave plants credit only for the associated cost components that are already in place at the plant. For example, for Regulatory Option 1, if a plant operates a one-stage chemical precipitation system for the treatment of FGD wastewater that includes all the steps included as the basis for the technology option other than sulfide precipitation, then EPA would include capital costs for the plant to install a reaction tank and sulfide chemical feed system and operating and maintenance costs for the amount of sulfide added to the system on a yearly basis. The compliance costs for all other pieces of equipment for the system would be set to zero.

EPA estimated capital, O&M, and 6-year recurring costs for a chemical precipitation system using the equations provided below.

Total Capital Costs = Purchased Equipment Costs + Purchased Equipment Installation Costs + Building Costs + Land Costs + Site Preparation Costs + Engineering Costs + Construction Expenses + Other Contractor Fees + Contingency Fees + Sludge Disposal Costs

Purchased equipment costs are the costs associated with purchasing the pieces of equipment required to construct a chemical precipitation system, in addition to ancillary equipment and freight costs. EPA included the following pieces of equipment in the calculation of the chemical precipitation system purchased equipment costs:

- Pumps;
- Tanks (e.g., equalization tanks, reaction tanks, holding tanks);
- Chemical feed systems;
- Mixers;

- Clarifiers;
- Filter presses; and
- Sand filters.

For each piece of equipment, EPA obtained cost information from vendors for various sizes of the equipment (e.g., flow, volume). EPA then related all of these to an associated flow rate using information based on the technology design basis (e.g., tank volume related to flow by design residence time). EPA then used the cost and flow information to generate an equation that could estimate the costs for any FGD wastewater flow rate.

Purchased equipment installation costs are the cost associated with installing those pieces of purchased equipment, including piping, instrumentation, calibration, and structural supports. Building, land, site preparation, engineering, construction, other contractor fee costs are the costs associated with preparing a specific site for the installation of the chemical precipitation equipment and the costs required for supervision and inspection of the installation. For each of these costs components, EPA estimated the capital costs by developing cost factors from data in the Steam Electric Survey. To develop these cost factors, EPA created ratios of the specific cost component to the total reported purchased equipment cost for each plant that reported cost data for an FGD chemical precipitation system. EPA then used the median or average ratio based on the plants in the analysis as the cost factor for calculating the costs. Therefore, once EPA calculated the total purchased equipment costs, EPA then multiplied the costs by each of the cost factors to estimate the costs for each of these components.

To calculate the sludge disposal costs, associated with on-site landfill disposal described in Section 9.5.3, EPA needed to estimate the quantity of sludge that would be generated annually. EPA used data from the Steam Electric Survey to compare the quantity of FGD wastewater treatment sludge generated to the FGD wastewater treatment system flow rate. EPA calculated a ratio of these values for each plant and used the median as a flow-normalized dewatered sludge generation rate in tons per gallon. Then based on the plant-specific FGD wastewater flow rate, EPA estimated the quantity of sludge generated by the system.

Total O&M Costs = Operating Labor Costs + Maintenance Labor Costs + Maintenance Materials Costs + Chemical Purchase Costs + Energy Costs + Sludge Transportation Costs + Sludge Disposal Costs + Compliance Monitoring Costs + Impoundment Operation Costs

Operating labor, maintenance labor, and maintenance material costs are the costs associated with the manual labor and materials required to operate and maintain the chemical precipitation system 24 hours per day, 365 days per year. To estimate these labor costs, EPA used data from the Steam Electric Survey to compare the labor costs to the flow rate of the system. From the costs reported in response to the survey and the associated FGD wastewater treatment flow rate, EPA developed equations to estimate the cost based on the flow rate. EPA then used these equations and each plant's FGD wastewater flow rate to determine the operating labor and maintenance labor costs. EPA performed a similar analysis to estimate the maintenance material costs by using data from the Steam Electric Survey to develop an equation relating FGD wastewater treatment flow to the total yearly maintenance material costs.

Chemical purchase costs are the costs associated with purchasing the chemicals required to operate the chemical precipitation system. EPA estimated chemical purchase costs using a chemical dosage rate (expressed in grams of chemical per liter of wastewater flow), the plant FGD wastewater flow rate, and chemical costs (expressed in dollars per ton). EPA determined the appropriate dosage rates based on the average chemical dosage rates used by the best available technology economically achievable (BAT) plants included in EPA's sampling program. EPA obtained chemical costs directly from chemical suppliers in dollars per ton.

Energy costs are the costs associated with the power requirement to run the chemical precipitation system. EPA obtained the power requirements for each piece of equipment used in the system from equipment vendors and used these power requirements to develop energy cost equations and estimate total energy consumption (in kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with compliance monitoring, transportation, disposal, and impoundment operations according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation above to estimate sludge transportation, disposal, and impoundment operation costs.

Total Recurring 6-Year Costs = Cost of Mercury Analyzer

EPA calculated 6-year recurring costs associated with operating a mercury analyzer, which is included in the system to allow plants to monitor the effluent quality on a daily basis to ensure the treatment system is effectively treating mercury to the proposed limitations. EPA estimated the total 6-year recurring costs by determining the cost and average expected life of a mercury analyzer, based on vendor information. EPA assumed that the expected life of a mercury analyzer is six years and that each plant will operate one analyzer for FGD wastewater.

9.6.2 Biological Treatment

Section 7.1.3 describes the anoxic/anaerobic biological treatment system that forms the basis for this technology option. For Regulatory Options 3 and 4, EPA estimated compliance costs to install and operate the anoxic/anaerobic system to treat FGD wastewater following the BAT chemical precipitation system. The anoxic/anaerobic system is specifically designed and operated to target removals of selenium (and other heavy metals). See Section 6.2 of the *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the FGD biological treatment cost methodology [U.S. EPA, 2013].

The system uses up-flow, fixed-film granular activated carbon (GAC) bed bioreactors, inoculated with a proprietary, site-specific mixture of bacterial cultures, through which the FGD wastewater passes.

EPA developed untreated FGD wastewater characteristics to use as the basis for cost development for the biological treatment system.[80] EPA developed these FGD wastewater characteristics from industry site visits, its sampling program, and the Clean Water Act (CWA) 308 monitoring program. A treatment vendor developed the specific anoxic/anaerobic biological treatment system design and system-level costs based on its evaluation of these untreated FGD wastewater characteristics. The anoxic/anaerobic biological system design consists of a series of two bioreactors operating in parallel trains. The number of trains and the size of the bioreactors are dependent on a plant's FGD wastewater flow rate. For flow rates greater than 40 gallons per minute (gpm), the vendor provided costs for customized field-erected biological treatment systems. For flow rates less than 40 gpm, the vendor provided costs for a low-flow, prefabricated modular reactor, which is more cost-effective for this flow range.

Based on site visits, EPA's sampling program, and the CWA 308 monitoring program, FGD wastewater temperatures can exceed the maximum operating temperature for the biological system, especially during the warmer seasons, and may require cooling prior to entering biological treatment. Therefore, the design basis includes a heat exchanger for certain southern plants determined to require cooling of FGD wastewater for biological treatment, based on set latitudinal and longitudinal coordinates where the average July temperature is 90°F or greater.

As noted in Section 9.4.1, EPA evaluated plant responses to the Steam Electric Survey to determine whether a biological treatment system for selenium removal is currently in place to treat FGD wastewater. As appropriate, plants operating this technology were given credit for having treatment in place, to ensure that incremental costs associated with compliance with the technology options are accurately assessed. EPA gave plants credit only for the associated cost components that are already in place at the plant.

EPA estimated capital and O&M costs for the anoxic/anaerobic system using the equations provided below.

Total Capital Costs = Purchased Equipment Costs + Purchased Equipment Installation Costs + Plant Overhead Engineering Costs + Sludge Disposal Costs

Purchased equipment costs are the costs associated with purchasing the pieces of equipment required to construct the anoxic/anaerobic biological system. EPA calculated purchased equipment costs by summing the costs of the anoxic/anaerobic biological system, the heat exchanger (for applicable plants), and a backwash recycle pump. The vendor provided EPA with cost equations based on FGD wastewater flow rate and backwash flow rate for the anoxic/anaerobic system and backwash recycle pump, respectively. The costs provided by the vendor include the following cost components:

[80] The untreated FGD wastewater characteristics developed for this analysis are similar to the characteristics identified in Section 6.1; however, they are slightly different because EPA had less data at the time this analysis was completed. The wastewater characteristics are included in *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* report [U.S. EPA, 2012].

- Two-stage bioreactor system (i.e., 2 reactors in series per train) with a 10-hour residence time for the system, operating 24 hours per day and 365 days per year. System-level costs include the following purchased equipment and associated ancillary equipment:
    - All process pumps, valves, and instruments;
    - Process and instrument compressed air system, valves, and lines;
    - Nutrient system, storage tank, and pumping;
    - Process piping and supports;
    - Concrete bioreactor tank walls and floor with epoxy-coated rebar and epoxy flake-glass coating;
    - Concrete backwash supply and backwash wastewater tank walls and floor with epoxy-coated rebar and epoxy flake-glass coating;
    - Concrete process and utility sump with pumps;
    - Support steel, access stairs, walkways, grating, handrails;
- Process equipment building with HVAC (concrete floor, block structure with steel roof);
- Engineering, commissioning, and project management labor (the project structure is executed by a consortium between the vendor and contractor with a balance of plant engineering as a sub-contractor); and
- Construction equipment, materials, and labor.

EPA used information obtained from vendors to develop cost equations for the heat exchanger, as well as the cooling water pumped needed for the system. Based on the chlorides level in the FGD wastewater and vendor recommendations, EPA developed heat exchanger costs for a carbon steel frame heat exchanger consisting of titanium plates. EPA estimated the size, and cost, of the cooling water pumps based on the flow for the FGD wastewater treatment system, accounting for the estimated heat transfer required to reduce the temperature of the wastewater to 95°F prior to entering the bioreactors.

Installation equipment costs are the costs associated with installing the purchased equipment, including any additional piping or instrumentation for the system. EPA estimated installation capital costs for the biological treatment system for each plant using two different installation cost factors. The first factor was provided by the vendor and is specific to installation of the anoxic/anaerobic biological system. The second factor was determined based on responses to the Steam Electric Survey and applies to installation of the heat exchanger and system pumps. This second factor is the same installation equipment cost factor used for the FGD chemical precipitation system.

Overhead engineering costs are costs associated with general process design and general engineering fees for the plant. EPA calculated the ratio of the overhead engineering costs to the total reported purchased equipment cost for each plant that reported cost data for an FGD chemical precipitation and/or biological treatment system. EPA then used the median ratio based on the plants in the analysis as the cost factor for calculating the costs.

The sludge generated by the biological treatment system is associated with the backwash from the system. The backwash water is recycled to the equalization tank prior to the FGD wastewater chemical precipitation system and is ultimately removed with the chemical precipitation sludge. The vendor provided an equation to calculate the estimated annual amount of dry solids generated during the backwash based on plant-specific FGD wastewater flow. EPA used the sludge generation rate to estimate the disposal costs, described in Section 9.5.3.

Total O&M Costs = Operating Labor Costs + Maintenance Labor Costs + Maintenance Materials Costs + Chemical Purchase Costs + Energy Costs + Compliance Monitoring Costs + Sludge Transportation Costs + Sludge Disposal Costs + Impoundment Operation Costs

Operating labor, maintenance labor, and maintenance material costs are the costs associated with the manual labor and materials required to operate and maintain the anoxic/anaerobic system 24 hours per day, 365 days per year. EPA estimated these labor costs using vendor data and industry responses to the Steam Electric Survey to estimate the number of full time equivalent (FTE) workers required to operate the system. EPA used this estimation and the median operating and maintenance labor rates from the Steam Electric Survey to calculate the labor costs. To calculate the maintenance material costs, EPA used Steam Electric Survey to compare the reported maintenance material costs to the sum of the energy, chemical, and operating and maintenance labor O&M costs plants operate FGD chemical precipitation and/or biological treatment systems. EPA used then used the calculated value and multiplied it by the sum of the energy, chemical, and operating and maintenance labor O&M costs to estimate the maintenance material costs for each plant.

Chemical purchase costs are the costs associated with purchasing the chemicals required to operate the anoxic/anaerobic biological system. EPA estimated the chemical purchase costs using nutrient dosages provided by the vendor, based on an assumed nitrate/nitrite (as nitrogen) concentration in the FGD wastewater, a nutrient cost provided by the vendor, and the plant-specific FGD wastewater flow rate.

Energy costs are the costs associated with the power requirement to run the anoxic/anaerobic biological system. The vendor provided an equation to calculate power requirements per gallon of FGD wastewater. EPA calculated the annual anoxic/anaerobic biological system energy consumption (in kWh/yr) by multiplying the anoxic/anaerobic biological system energy requirement by the plant-specific FGD wastewater flow and backwash flow. For the pumps, EPA developed energy cost equations based on the power requirements provided by equipment vendors (in kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with compliance monitoring, transportation, disposal, and impoundment operations according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation above to estimate sludge transportation, disposal, and impoundment operation costs.

9.6.3 Vapor-Compression Evaporation

Section 7.1.3 describes the vapor-compression evaporation system that forms the basis for this technology option. The purpose of the vapor-compression evaporation system is to evaporate and condense the water from the FGD wastewater to produce a clean distillate stream and a concentrated brine solution. The concentrated brine solution is then further treated to generate a solid by-product. See Section 6.3 of the *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the FGD vapor-compression evaporation cost methodology [U.S. EPA, 2013].

As noted in Section 9.4.1, EPA evaluated plant responses to the Steam Electric Survey to determine whether a vapor-compression evaporation system is currently in place to treat FGD wastewater. As appropriate, plants operating this technology were given credit for having "treatment in place" to ensure that incremental costs associated with compliance with the technology options are accurately assessed. EPA gave plants credit only for the associated cost components that are already in place at the plant.

EPA estimated capital and O&M for a vapor-compression evaporation system using the equations provided below.

Total Capital Costs = Purchased Equipment Costs + Purchased Equipment Installation Costs + Sludge Disposal Costs

Purchased and installation equipment costs are the costs associated with purchasing and installing the pieces of equipment, including extra piping, instrumentation, and support structures, required to construct a vapor-compression evaporation system. EPA estimated purchased and installation costs using data from vendors. The vendors provided total system costs for two different FGD wastewater treatment system flow rates. The system costs include the following pieces of equipment:

- Water softener;
- Mechanical vapor compression brine concentrator; and
- Forced-circulation crystallizer.

Using the information provided by the vendors, EPA developed costs equations to estimate the plant-specific compliance costs to install the system. For the brine concentrator and crystallizer, EPA developed the equation to relate the costs to the FGD wastewater treatment system flow rate. The cost for the softener is based on a percentage of the brine concentrator and the crystallizer costs. EPA estimated installation costs using a factor provided by the vendors and the calculated total purchased equipment costs.

Sludges generated by the vapor-compression evaporation system include softening sludge and crystallizer sludge. Vendors provided an equation to calculate the estimated sludge based on the plant-specific FGD wastewater flow. EPA used the sludge generation rate to estimate the disposal costs, described in Section 9.5.3.

Total **O&M Costs** = Operating Labor Costs + Maintenance Labor Costs + Maintenance Materials Costs + Chemical Purchase Costs + Energy Costs + Compliance Monitoring Costs + Sludge Transportation Costs + Sludge Disposal Costs + Impoundment Operation Costs

Operating labor, maintenance labor, and maintenance material costs are the costs associated with the manual labor and materials required to operate and maintain a vapor-compression evaporation system 24 hours per day, 365 days per year. To calculate labor rates, EPA used industry responses to Steam Electric Survey for chemical precipitation systems with and without subsequent vapor-compression evaporation treatment. EPA determined one operator, 24 hours per day, is required to operate the system based on observations during a site visit to a plant operating a vapor-compression evaporation system to treat FGD wastewater. The median operating labor rate was multiplied by the expected labor hours to determine the operating labor costs.

Vapor-compression evaporation system vendor information was insufficient for use in estimating maintenance labor and maintenance material costs; therefore, EPA used the chemical precipitation factors, described in Section 9.6.1, to calculate these cost elements.

Chemical purchase costs are the costs associated with purchasing the chemicals required to operate the vapor-compression evaporation system. The softening portion of the system requires soda ash to soften the wastewater. The vendor provided the cost to purchase soda ash for one flow rate [HPD, 2009]. EPA used this cost and associated flow rate to generate a dollar per gallon per minute value to estimate costs based on the plant-specific FGD wastewater flow rate.

Energy costs are the costs associated with the power requirement to run the vapor-compression evaporation system. EPA obtained the power requirements for each piece of equipment used in the system from equipment vendors and used these power requirements to develop energy cost equations and estimate total energy consumption (in kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with compliance monitoring, transportation, disposal, and impoundment operations according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation above to estimate sludge transportation, disposal, and impoundment operation costs.

9.6.4 Estimated Industry-Level Costs for FGD Wastewater by Treatment Option

Table 9-3 presents the estimated capital and O&M costs on an industry level for each FGD wastewater treatment technology discussed in the sections above, including transport, disposal, and impoundment costs. The table also includes the number of plants incurring costs for each treatment technology. The costs presented in the table represent the compliance costs for those generating units expected to be subject to the proposed ELGs; therefore, oil-fired units and units with a capacity of 50 MW or less are not included because they do not need to install the technology basis to meet the new BAT limitations (which are based on the current BPT requirements for these units). See EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units [U.S. EPA, 2013].

Table 9-3. Estimated Industry-Level Costs for FGD Wastewater Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year)[a]
Chemical Precipitation	116	$1,450,000,000	$194,000,000	$9,900,000	($33,000,000)
Chemical Precipitation followed by Biological Treatment	116	$2,500,000,000	$257,000,000	$9,900,000	($33,000,000)
Chemical Precipitation followed by Vapor-Compression Evaporation	116	$6,240,000,000	$1,030,000,000	$9,900,000	($33,000,000)

a – The values in this column are negative because they represent cost savings.

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2011].

EPA also estimated the industry-level costs for only those plants with a total plant-level wet scrubbed capacity of 2,000 MW or greater to install the chemical precipitation followed by biological treatment technology. To estimate these industry-level costs, EPA zeroed the costs from its FGD biological treatment cost outputs and for those plants with a total plant-level wet scrubbed capacity of less than 2,000 MW. For all plants with a total plant-level wet scrubbed capacity of 2,000 MW or greater, EPA used the costs from its FGD biological treatment cost outputs. For more details on how EPA estimated these plant-level FGD biological treatment costs, see the memorandum entitled "Memorandum to the Rulemaking Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Options 3a and 3b" [ERG, 2013c].

Table 9-4 presents the estimated capital, O&M, and recurring costs on an industry-level associated with dry or closed-loop recycle bottom ash handling conversions for this analysis. The table also includes the number of plants incurring compliance costs. The costs presented in the table represent the compliance costs for those generating units expected to be subject to the proposed ELGs for Regulatory Option 4a; therefore, oil-fired units and units with a capacity of 400 MW or less are not included because they do not need to install the technology basis to meet the new BAT limitations (which are based on the current BPT requirements for these units).

Table 9-4 presents the estimated capital and O&M costs on an industry level for the FGD chemical precipitation followed by biological treatment wastewater treatment technology discussed in the sections above, including transport, disposal, and impoundment costs. The table also includes the number of plants incurring costs for each treatment technology. The costs presented in the table represent the compliance costs for those generating units expected to be subject to the proposed ELGs; therefore, oil-fired units and units at plants with a total plant-level wet scrubbed capacity of less than 2,000 MW are not included because they do not need to install the technology basis to meet the new BAT limitations (which are based on the current BPT requirements for these units).

Table 9-4. Estimated Industry-Level Costs for FGD Wastewater Based on Oil-Fired Units and Units at Plants with a Total Plant-Level Wet Scrubbed Capacity of Less Than 2,000 MW Not Installing Technology Basis

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year)[a]
Chemical Precipitation followed by Biological Treatment	17	$600,000,000	$67,600,000	$1,450,000	($5,640,000)

a – The values in this column are negative because they represent cost savings.

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2011].

9.6.5 Compliance Costs Associated with Planned FGD Systems

In addition to existing sources, EPA also evaluated costs of compliance associated with planned installations of FGD systems. Implementation of air pollution controls may create new wastewater streams at power plants. The compliance costs and pollutant removal estimates included in this document reflect consideration of wastestreams generated by air pollution controls that will likely be in operation at plants at the time of ELG promulgation. However, EPA recognizes that some recently promulgated Clean Air Act requirements may lead to additional air pollution controls (and resulting wastestreams) at existing plants beyond the date of ELG promulgation. In an effort to confirm that the proposed ELGs would be economically achievable in such cases, EPA also conducted a sensitivity analysis that forecasts future installations of air controls through 2020 and the associated costs of complying with the proposed ELGs for the wastewater that may result from the forecasted air control installations.[81] These sensitivity analyses are described in more detail in the memorandum entitled “Flue Gas Desulfurization Future Profile Sensitivity Analysis” [ERG, 2013a].

9.7 Ash Transport Water

As discussed in Section 4.2.1, combusting coal and oil in steam electric boilers produces a residue of noncombustible fuel constituents, referred to as ash. The ash that is light enough to be carried out of the boiler is referred to as fly ash and the heavier ash that falls to the bottom of the boiler is referred to as bottom ash.

Based on survey responses, plants usually collect and handle fly ash and bottom ash separately. Fly ash is either handled dry and pneumatically transferred dry to silos for temporary

[81] EPA expects that plants will be in compliance with new federal and state air pollution control requirements by 2020.

storage or sluiced with water to an impoundment. Bottom ash is either collected in a water-filled hopper positioned below the hopper and sluiced with water to an impoundment, collected under the boiler using a mechanical drag system and stored in an outdoor pile for temporary storage, or pneumatically transferred to silos for temporary storage.

Because of the development of ash handling systems that require little to no water and the ability to market dry fly and/or bottom ash, plants have been converting handling operations on existing steam electric generating units from wet sluicing operations to systems that do not transport the ash with water. The following sections describe the technology bases used to estimate the compliance costs associated with converting from wet to dry fly ash handling and wet to dry or closed-loop recycle bottom ash handling.

9.7.1 Fly Ash Transport Water

EPA estimated capital, O&M, and 10-year recurring costs associated with converting wet fly ash handling systems (specifically wet fly ash sluicing systems) to dry vacuum fly ash handling systems for steam electric generating units generating fly ash. Section 7.2.3 provides more details on the dry vacuum fly ash handling system.

In addition to the dry vacuum system, EPA evaluated a different technology for generating units with significantly less fly ash production. These generating units are usually oil-fired. Based on Steam Electric Survey data, EPA evaluated costs for oil-fired units operating less than 100 days per year to use a vactor truck to collect and handle the fly ash to comply with a zero discharge requirement. See Chapter 7 of the *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the fly ash cost methodology [U.S. EPA, 2013].

EPA's approach for estimating costs associated with converting to dry vacuum systems and for using vactor trucks is described in more detail below.

Dry Vacuum Conversion

Based on data from the Steam Electric Survey and site visits, EPA determined that a single steam electric generating unit can be equipped with both wet and dry handling capabilities. Therefore, not all steam electric generating units require complete conversion costs depending on the equipment, and the capacity of that equipment, already operating at the plant. As appropriate, plants with wet and dry handling systems were given credit for having this equipment at the plant. Therefore, to estimate compliance costs for a fly ash handling conversion to a dry vacuum system, EPA developed a costing approach for three separate portions of the system:

- **Conveyance**. The portion of the fly ash handling system from the bottom of the collection hopper to the intermediate storage destination that includes the mechanical exhauster, piping, valves, and filter-separators necessary to pull and convey ash from the bottom of the hopper. EPA calculated conveyance costs at the steam electric generating unit level.

- **Intermediate Storage**. The destination to which the dry fly ash is conveyed from the bottom of the hopper. The intermediate storage includes the structure itself (e.g., the silo), including the vacuum equipment necessary to receive the ash from the conveyance lines, and the unloading equipment necessary for moisture conditioning prior to transportation and disposal.[82] EPA calculated intermediate storage costs at the plant level.
- **Transportation/Disposal**. The trucking equipment and operation to move the dry fly ash to its final destination (e.g., on-site or off-site landfill). EPA calculated transport/disposal costs at the plant level.

For example, the vacuum lines for a generating unit may have the capacity to handle all of the dry fly ash generated, but the silo may not be large enough to store all of the dry fly ash. There EPA would only estimate compliance costs associated with the additional intermediate storage (silo capacity) required.

EPA estimated capital, O&M, and 10-year recurring costs for the conversion to dry fly ash handling using a dry vacuum system using the equations provided below. EPA calculated the capital, O&M, and 10-year recurring costs by summing the estimated costs for the conveyance, intermediate storage, and transport/disposal portions of the system.

Total Capital Costs = Purchased Equipment Costs + Purchased Equipment Installation Costs + Plant Overhead Engineering Costs + Fly Ash Disposal Costs

Purchased equipment costs are the costs associated with purchasing all equipment to retrofit all generating units, collecting fly ash with a wet sluicing system, with a dry vacuum conveyance system. EPA calculated purchased equipment costs by summing the costs of dry vacuum conveyance system(s), the concrete or steel silo(s), silo aeration equipment, and pugmill(s). EPA calculated equipment costs for conveyance on a generating unit level, and calculated silo and pugmill equipment costs at a plant level. EPA estimated conveyance, silo, and pugmill equipment costs using a relationship between capital costs and wet fly ash generation rate obtained from industry vendors.

EPA estimated installation capital costs for the fly ash handling conversion, including all system elements, for each plant using an installation factor determined from Steam Electric Survey data. EPA supplemented this information with cost data from industry vendors to determine an installation factor for the conveyance and intermediate storage system elements. EPA estimated the installation costs by applying the calculated factor by the purchased equipment cost.

Plant overhead engineering costs were determined from Steam Electric Survey data. Based on survey responses, EPA calculated a median installation factor for the conveyance and

[82] Plants may have a silo; however, they may need to install the equipment for moisture conditioning ash prior to unloading. Therefore, the intermediate storage costs are based on two cost indicators, one of the silo and one for the pugmill.

intermediate storage system elements. EPA estimated the overhead costs by applying the calculated factor to the purchased equipment and installation costs.

Total O&M Costs = Operating Labor Costs + Maintenance Labor Costs + Maintenance Materials Costs + Energy Costs + Fly Ash Transport Costs + Fly Ash Disposal Costs + Impoundment Operation Costs

EPA calculated the amount of moisture-conditioned fly ash generated from the handling conversion using wet fly ash generation rate at the plant-level and an average moisture content of fly ash from the Steam Electric Survey, supplemented with vendor data. EPA used the moisture-conditioned fly ash tonnage to estimate the disposal costs, described in Section 9.5.

Operating and maintenance labor costs are the costs associated with operating and maintaining the conveyance, intermediate storage, and transport/disposal portions of the dry vacuum system. EPA calculated operating labor costs using the labor rate, the estimated number of required operator hours per day, and the total number of days the generating units operated. EPA calculated the maintenance labor costs using the labor rate and the estimated maintenance hours per year. EPA used the Steam Electric Survey data, supplemented with U.S. Bureau of Labor Statistics data, to calculate the labor rate for fly ash conversion costs [U.S. Bureau of Labor Statistics, 2010]. EPA estimated the number of required operator hours per day and maintenance hours per year using data provided in the Steam Electric Survey. Additionally, EPA used the number of unit operating days in 2009 reported the Steam Electric Survey.

In addition to the intermediate storage system operating labor costs, EPA also estimated O&M costs for operating dust suppression water trucks around the fly ash unloading area, including operating labor and fuel costs, if appropriate.[83] EPA estimated the water truck operating labor cost using a water truck labor rate, number of required operator hours per day, the number of operating days per year, and the number of silos. To determine the water truck labor rate, EPA selected the national average loaded labor rate for industrial truck/tractor operators as reported by the U.S. Bureau of Labor Statistics [U.S. Bureau of Labor Statistics, 2010]. EPA estimated the number of required operator hours per day and the number of operating days using data from the Steam Electric Survey. EPA calculated the number of silos as part of the compliance cost methodology. EPA estimated the fuel costs associated with the water trucks by multiplying the number of hours each water truck operates by the number of water trucks, the distance the water truck travels every hour, and the gas mileage and fuel cost. The number of water trucks required at a plant was determined using data from the *Regulatory Impact Analysis For EPA's Proposed RCRA Regulation Of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry* [ORCR, 2010], based on the dry fly ash tonnage produced at the plant after the handling conversion. The fuel consumption of the water truck was

[83] For plants that already have some portion of dry fly ash handling, EPA only included additional costs for water trucks if the additional tonnage that would now be handled dry would require the plant to purchase and operate additional water trucks. See Section 7.1.9 of the *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* for additional details on the water truck methodology [U.S. EPA, 2012].

determined from vendor contacts. EPA assumed the same trip distance and fuel cost from the disposal technology cost methodology.

Similarly, EPA used data from the Steam Electric Survey to determine a maintenance materials factor with respect to the total O&M costs for conveyance and intermediate storage system elements, respectively. EPA calculated a median maintenance material factor for each system element (e.g., conveyance, intermediate storage) and applied it to the calculated O&M.

Energy costs are the costs associated with the power requirement to run the dry vacuum system. EPA obtained the power requirements for each piece of equipment (pumps and pugmills) used in the system from the vendors and used these power requirements to develop energy cost equations for the system pumps and pugmill(s) and estimate total energy consumption (in kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with compliance monitoring, transportation, disposal, and impoundment operations according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation above to estimate fly ash transportation, disposal, and impoundment operation costs.

Total 10-Year Recurring Costs = Cost of Water Truck

EPA calculated 10-year recurring costs associated with intermediate storage water trucks by determining the cost, expected life, and number of water trucks required (from ORCR regulatory impact analysis information). EPA determined that the expected life of a water truck is ten years.

Vactor Truck Conversion

For oil-fired units that operate less than 100 days, EPA used a different approach for estimating capital and O&M costs because of the small amount of fly ash generated from these units. This approach includes piping the fly ash away from the primary particulate collection system using a vactor truck operated by a third-party contractor. The fly ash is drawn to a 10-yard roll-off vacuum container stored at the end of the fly ash lines. To remove the fly ash from the vacuum container, the plant would contract a vendor, on a yearly basis, to vacuum fly ash from the vacuum container using a vactor truck.

The capital costs associated with this system include installing the piping from the primary particulate collection system to the location were the roll-off vacuum container will be stored. Capital costs for the vactor truck system were determined using a direct relationship between capital cost and the fly ash generation rate, similar to the dry vacuum system. EPA used Steam Electric Survey data to determine the capital cost estimates. Similarly, EPA used Steam Electric Survey data and plant contact information to develop a relationship between the O&M costs for conveyance and storage and the fly ash generation rate.

9.7.2 Bottom Ash Transport Water

EPA estimated capital, O&M, three-year recurring, five-year recurring, and 10-year recurring costs associated with converting bottom ash handling systems from wet sluicing to mechanical drag or remote mechanical drag systems for generating units generating bottom ash. EPA selected two systems, the mechanical drag system (MDS) and the remote MDS, as the basis for the dry and closed-loop recycle systems, respectively, based on system operation data from vendors and operation data from the Steam Electric Survey. The compliance costs estimated by EPA include the conveyance system conversion, the additional required bottom ash storage, the transport and disposal of the bottom ash, and impoundment costs associated with the change in bottom ash handling. See Chapter 8 of the *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more details on the bottom ash cost methodology [U.S. EPA, 2013].

EPA estimated costs for both MDS and remote MDS systems. The cost estimates reflect fully erected and commissioned systems, including equipment, controls, foundations, and field labor. For more detail on the MDS and remote MDS equipment, see Sections 7.3.2 and 7.3.3 of this report.

Because EPA evaluated two technologies for bottom ash handling conversions, EPA estimated compliance costs for both technologies for each plant. EPA selected the technology associated with the lowest estimated annualized cost for the combined system conversion, transport and disposal, and impoundment costs, at a plant level, as the cost basis for the plant.

EPA estimated capital, O&M, three-, five-, and 10-year recurring costs for MDS and remote MDS conversions using the equations provided below. Because the MDS and remote MDS share similar system elements, EPA calculated the O&M in four components. The components include the following:

- Shared O&M Costs – Conveyance, transport, disposal, and impoundment O&M costs applicable to both MDS and remote MDS;
- Additional Remote MDS O&M Costs – Additional O&M costs, primarily chemical costs associated with the remote MDS;
- Intermediate Storage O&M Costs – Storage O&M costs applicable to both MDS and remote MDS; and

Wet Sluicing O&M Costs – Costs associated with the currently operating wet sluicing system.

Total MDS Capital Costs = Conveyance & Intermediate Storage Equipment Costs + Plant Overhead Engineering Costs + Bottom Ash Disposal Costs

Conveyance and intermediate storage equipment costs are the costs associated with the purchase and installation for a fully erected and commissioned MDS, including equipment, controls, foundations, and field labor. EPA estimated equipment costs on a generating unit basis using a relationship between capital cost and unit capacity (in MW). EPA obtained unit capacity information from the Steam Electric Survey. Vendors provided the relationship between the cost and the generating capacity. The conveyance and intermediate storage costs provided for the MDS system include the costs for a semi-dry silo. After calculating the capital costs at the unit level, EPA summed the capital costs to a plant level.

Plant overhead engineering costs were determined from Steam Electric Survey. Based on survey responses, EPA calculated a median installation factor for the conveyance and intermediate storage system elements. EPA estimated the overhead costs by applying the calculated factor to the conveyance and intermediate storage equipment costs.

EPA calculated the amount of moisture-conditioned bottom ash generated from the handling conversion using the wet bottom ash generation rate at the plant-level and an average moisture content of bottom ash from the Steam Electric Survey, supplemented with vendor data. EPA used the moisture-conditioned bottom ash tonnage to estimate the disposal costs, described in Section 9.5.

Conveyance and intermediate storage equipment costs are the costs associated with the purchase and installation for a fully erected and commissioned remote MDS, including equipment, controls, foundations, and field labor. EPA estimated equipment costs on a generating unit basis using a relationship between capital cost and unit capacity (in MW). EPA obtained unit capacity from the Steam Electric Survey. Vendors provided the relationship between the cost and the capacity. The conveyance and intermediate storage costs provided for the remote MDS system include the costs for a semi-dry silo. After calculating the capital costs at the unit level, EPA summed the capital costs to a plant level.

Recycle pump costs are the costs associated with the purchase of a pump used to recycle the sluice water from the remote MDS back to the steam electric generating unit. The chemical feed system costs are the costs associated with the purchase of a chemical feed system to adjust the pH of the sluice water as required to completely recycle the bottom ash sluice. To estimate the costs of the recycle pump and the chemical feed system for the remote MDS, EPA used the same type of recycle pump type and chemical feed system used in the FGD chemical precipitation cost methodology. See Section 6.1.6.1 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2013]. The recycle pump and chemical feed system costs include the freight costs associated with each piece of equipment. To estimate these costs, EPA used the bottom ash sluice rate, in gallons per day, from the Steam Electric Survey at a generating unit level and summed them to the plant level. EPA obtained recycle pump and chemical feed system cost relationships and estimated freight costs from vendors.

Installation equipment costs are the costs associated with the installation of the recycle pump and chemical feed system. EPA estimated capital installation costs associated with the recycle pump and chemical feed system using an installation factor calculated based on Steam Electric Survey data and vendor data used in the fly ash conveyance and intermediate storage cost methodology.

Plant overhead engineering costs and disposal costs are calculated using the same methodology described for the total MDS capital costs.

Total Shared O&M Costs = Conveyance Operating Labor Costs + Conveyance Maintenance Labor Costs + Conveyance Maintenance Materials Costs + Conveyance Energy Costs + Bottom Ash Transportation Costs + Bottom Ash Disposal Costs + Impoundment Operation Costs

Conveyance operating and maintenance labor costs are the costs associated with operating and maintaining the conveyance portion of the bottom ash handling system. EPA calculated the conveyance O&M labor costs using the labor rate and the number of required operator or maintenance hours per year for operating or maintenance labor, respectively. EPA used the Steam Electric Survey data supplemented with U.S. Bureau of Labor Statistics data to calculate the labor rate for all system elements for the bottom ash conversion costs. Operating and maintenance hours per year were calculated using data in the Steam Electric Survey.

Similarly, EPA used data from the Steam Electric Survey to determine a maintenance materials factor with respect to the total O&M costs for the conveyance portion of the bottom ash handling system. EPA applied the median maintenance material factor to the total conveyance O&M costs to estimate the maintenance material costs.

Energy costs are the costs associated with the costs required to power the conveyance portion of the bottom ash handling system. Vendors supplied the size and horsepower specifications for pumps for the MDS and remote MDS systems based on generating unit capacity (in MW). EPA used the vendor data to create equations for estimating the energy consumption at the plant (in kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. DOE, 2011].

EPA estimated the O&M costs associated with transportation, disposal, and impoundment operations according to the methodologies described in Section 9.5. EPA used the same estimated tonnage described for the capital cost equation above to estimate bottom ash transportation, disposal, and impoundment operation costs.

Total Additional Remote O&M Costs = Chemical Purchase Costs + Chemical Pump Energy Costs

Chemical purchase costs are the costs associated with purchasing chemicals to control pH levels for bottom ash sluice recirculation. To calculate chemical purchase costs, EPA estimated the hydrogen chloride (HCl) consumption, chemical purchase, and freight costs. EPA calculated the HCl consumption using wet sluicing data and operating days in the Steam Electric Survey. For more explanation regarding estimating chemical consumption, see Section 6.1.7.4 in EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2013].

Energy requirements unique to the remote MDS consist of the energy required to operate the pump that returns sluice water from the sump pit back to the boiler area and the HCl feed pump. EPA determined this additional energy consumption (in kWh/yr) by calculating and summing the annual power consumption for these two pumps for each unit, and then summing these unit-level consumptions to calculate plant-level energy consumption. Pump energy consumption (in kWh/yr) is a function of pump horsepower. EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. EPA, 2013].

Total Intermediate Storage O&M Costs = Storage Operating Labor Costs + Storage Maintenance Labor Costs + Storage Maintenance Materials Costs + Storage Energy Costs

Intermediate storage labor costs are the costs associated with operating and maintaining the intermediate storage area where bottom ash is conveyed prior to disposal. EPA calculated intermediate storage O&M labor costs using an estimated labor rate and the number of required operator or maintenance hours per year for operating or maintenance labor, respectively. EPA used the Steam Electric Survey data supplemented with U.S. Bureau of Labor Statistics data to calculate the labor rate for all system elements for the intermediate storage costs. EPA calculated O&M hours per year using data in the Steam Electric Survey.

Similarly, EPA used data from the Steam Electric Survey to determine a maintenance materials cost factor with respect to the total O&M costs for the intermediate storage of the bottom ash. EPA applied the median maintenance material cost factor to the total intermediate storage O&M costs to estimate the maintenance material costs.

Intermediate storage energy costs are the costs associated with power requirements for the pugmill unloader at the silo. EPA used vendor supplied size and horsepower specifications for pugmill unloaders to calculate the intermediate storage energy consumption (in kWh/yr). EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. EPA, 2013].

Total Wet Sluicing O&M Costs = Sluicing Operating Labor Costs + Sluicing Maintenance Labor Costs + Sluicing Maintenance Materials Costs+ Sluicing Energy Costs

The sluicing operating and maintenance labor costs are the costs associated with operating and maintaining the sluicing portion of the bottom ash handling system. EPA calculated wet sluicing O&M labor costs using an estimated labor rate and the number of required operator or maintenance hours per year for operating or maintenance labor, respectively. EPA used the Steam Electric Survey data supplemented with U.S. Bureau of Labor Statistics data to calculate the labor rate for all system elements for the wet sluicing costs. EPA estimated operating hours using median worker hours per day and the total number of days the unit operated in 2009, obtained from the Steam Electric Survey. EPA used industry responses from the Steam Electric Survey for wet sluicing systems to calculate median operating worker hours per day for the conveyance portion of the system. EPA used the number of unit operating days in 2009, reported in the Steam Electric Survey, to calculate the total O&M days per year. EPA estimated maintenance hours per year using the maintenance labor median worker hours per year obtained from industry responses to the Steam Electric Survey.

EPA estimated maintenance material costs based on an evaluation of O&M costs reported in the Steam Electric Survey for generating units with wet sluicing bottom ash handling systems. EPA calculated the ratio of reported maintenance material costs to the total sum of operating labor, maintenance labor, energy, and other O&M costs. EPA applied the median maintenance material cost factor to the total conveyance O&M costs to estimate the maintenance material costs.

Wet bottom ash conveyance energy consumption (in kWh/yr) is a function of pump horsepower. EPA estimated sluice pump horsepower using the same horsepower equation as that developed for sump pumps for the FGD wastewater chemical precipitation costing methodology; see Section 6.1.6.1 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2013]. The pump horsepower was estimated as a function of sluice flow rate, obtained from the Steam Electric Survey. EPA estimated the hours of operation for the system using the operating days of the generating unit and an estimated value for the number of hours the system conveys bottom ash supplied by vendors. EPA used the national 2010 energy cost of 4.05 cents per kilowatt hour to calculate the energy cost [U.S. DOE, 2011].

Total MDS O&M Costs = Shared O&M Costs + Intermediate Storage O&M Costs – Wet Sluicing O&M Costs

As previously described, EPA estimated four different cost components to calculate total O&M costs for each system because different components apply to the two different systems. EPA estimated MDS costs using the shared, intermediate storage, and wet sluicing costs. EPA subtracted wet sluicing cost components from the calculated costs to represent the incremental cost achieved by the MDS system.

Total Remote MDS O&M Costs = Shared O&M Costs + Additional Remote MDS O&M Costs + Intermediate Storage O&M Costs

Total O&M costs for the remote MDS system include the shared and intermediate storage costs; however, EPA also included additional costs for operating the recycle pump and chemical feed system to allow for complete recycle. EPA did not subtract wet sluicing O&M costs from the remote MDS costs because the system still includes the operation of the existing sluicing operations.

Total 3-Year Recurring Costs = Cost of Mechanical Drag Chain for MDS

EPA calculated three-year recurring costs associated with the drag chain for the MDS. The drag chain is the component of the system that drags the bottom ash from the water bath, up the incline to intermediate storage. EPA calculated the three-year recurring cost by determining the cost and expected life of a drag chain for the MDS. Because the drag chain of the MDS system is located underneath the boiler, and more susceptible to large chunks of falling bottom ash, EPA determined that the expected life of a MDS drag chain is three years.

Total 5-Year Recurring **Costs** = Cost of Mechanical Drag Chain for Remote MDS

EPA calculated five-year recurring costs associated with the drag chain for the remote MDS. The drag chain is the component for the remote MDS is the same described for the MDS. EPA calculated the five-year recurring cost by determining the cost and expected life of a drag chain for the remote MDS. Because the drag chain of the remote MDS system is not located directly underneath boiler, and less likely to be damaged by falling bottom ash, EPA determined that the expected life of a remote MDS drag chain is five years.

One Time Costs = Engineering Consulting Cost

EPA reviewed plants operating bottom ash handling systems that recycled the majority of their bottom ash sluice from wet handling operations. Instead of estimating compliance costs for a full conversion to a MDS or remote MDS system, EPA estimated a one-time cost associated with consulting an engineer to completely close the bottom ash recycle system, eliminating all discharges of bottom ash transport water. See Section 8.5 of EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report [U.S. EPA, 2013].

9.7.3 <u>Estimated Industry-Level Costs for Ash Handling Conversions</u>

Table 9-5 presents the estimated capital, O&M, and recurring costs on an industry level associated with dry fly ash handling conversions, while Table 9-6 presents the estimated capital, O&M, and recurring costs on an industry-level associated with dry or closed-loop recycle bottom ash handling conversions. Both tables also include the number of plants incurring compliance costs. The costs presented in the table represent the compliance costs for those generating units expected to be subject to the proposed ELGs; therefore, oil-fired units and units with a capacity of 50 MW or less are not included because they do not need to install the technology basis to meet the new BAT limitations (which are based on the current BPT requirements for these units). See EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units [U.S. EPA, 2013].

Table 9-5. Estimated Industry-Level Costs for Fly Ash Handling Conversions Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	10-Year Recurring Cost ($/10-year)[a]
66	$398,000,000	$177,000,000	($20,700,000)

a – The values in this column are negative because they represent cost savings.

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2011].

Table 9-6. Estimated Industry-Level Costs for Bottom Ash Handling Conversions Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	One Time Cost ($)	3-Year Recurring Cost ($/3-year)	5-Year Recurring Cost ($/5-year)	10-Year Recurring Cost ($/10-year)[a]
240	$4,470,000,000	$494,000,000	$583,000	$28,200,000	$64,800,000	($83,800,000)

a – The values in this column are negative because they represent cost savings.

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2011].

EPA also estimated the industry-level costs for plants to convert only the generating units that are greater than 400 MW to dry or closed-loop recycle bottom ash handling systems. However, EPA used a different approach to estimate the plant-level costs for this analysis. For those plants with all generating units with a nameplate capacity of 400 MW or less, EPA zeroed the costs from its bottom ash cost outputs and for those plants with all generating units with a nameplate capacity greater than 400 MW, EPA used the costs from its bottom ash cost outputs. For those plants that have at least one generating unit with a nameplate capacity of 400 MW or less and at least one other generating unit with a nameplate capacity of greater than 400 MW, EPA approximated the plant-level bottom ash costs. To perform this approximation, EPA calculated a plant-level bottom ash adjustment factor based on the amount of bottom ash generated by the generating units expected to incur compliance costs with a nameplate capacity greater than 400 MW compared to the total amount of bottom ash generated at the plant for those generating units expected to incur compliance costs (excluding the generating units with a nameplate capacity of 50 MW or less). EPA then multiplied the bottom ash adjustment factors by the plant-level bottom ash compliance costs to estimate the bottom ash compliance costs for this analysis. For more details on how EPA estimated these plant-level bottom ash costs, see the memorandum entitled “Memorandum to the Rulemaking Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a” (DCN SE03834).

Table 9-7 presents the estimated capital, O&M, and recurring costs on an industry-level associated with dry or closed-loop recycle bottom ash handling conversions for this analysis. The table also includes the number of plants incurring compliance costs. The costs presented in the table represent the compliance costs for those generating units expected to be subject to the proposed ELGs for Regulatory Option 4a; therefore, oil-fired units and units with a capacity of

400 MW or less are not included because they do not need to install the technology basis to meet the new BAT limitations (which are based on the current BPT requirements for these units).

Table 9-7. Estimated Industry-Level Costs for Bottom Ash Handling Conversions Based on Oil-Fired Units and Units 400 MW or Less Not Installing Technology Basis

Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	One Time Cost ($)	3-Year Recurring Cost ($/3-year)	5-Year Recurring Cost ($/5-year)	10-Year Recurring Cost ($/10-year)[a]
115	$2,580,000,000	$255,000,000	$314,000	$1,120,000	$37,800,000	($35,600,000)

a – The values in this column are negative because they represent cost savings.

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2011].

9.8 Combustion Residual Landfill Leachate

EPA estimated capital and O&M costs associated with installing and operating a one-stage chemical precipitation wastewater treatment system to treat combustion residual landfill leachate. Note that as described in Section 9.2.4, EPA finds that plants with combustion residual surface impoundment leachate will not incur costs associated with any proposed leachate requirements. Where a plant generates both landfill leachate and FGD wastewater, EPA evaluated the leachate compliance costs in conjunction with FGD wastewater treatment (i.e., those plants discharging leachate and FGD wastewater would use only one wastewater treatment system to treat the combined leachate and FGD wastewater flow.[84] However, for plants that do not have FGD wastewater, EPA calculated the cost for a chemical precipitation to handle just the landfill leachate using the equations in Sections 9.6.1 associated with one-stage chemical precipitation. [ERG, 2013d]

Of the plants identified as having some level of treatment in place for FGD chemical precipitation, 29 plants also discharge landfill leachate. EPA conducted an analysis to determine if the existing FGD wastewater treatment systems at these plants would be sufficient to treat the amount of combustion residual landfill leachate produced at the plants in addition to the FGD wastewater that is currently being treated. EPA compared the design flow rate (reported in Part D Section 5.1 of the Steam Electric Survey) for each treatment system to the plant-specific wastewater flow (i.e., FGD wastewater plus combustion residual landfill leachate). If this new flow (FGD wastewater plus combustion residual landfill leachate) was less than the specified design flow rate for the existing chemical precipitation system, EPA determined that the existing system could support the additional flow. EPA identified 10 of these plants had sufficient capacity to handle the additional combustion residual landfill leachate flow; however, 19 of the plants did not have the capacity to treat the additional combustion residual landfill leachate flow.

[84] The technology option for combustion residual landfill leachate is one-stage chemical precipitation while the technology option for FGD wastewater is one-stage chemical precipitation followed by biological treatment. While the plant could technically meet the proposed leachate limitations and standards with only a one-stage chemical precipitation system, installing two separate treatment systems for the leachate and FGD wastewater would be more expensive than a single system which subjects leachate to both chemical precipitation and biological treatment.

For these 19 plants, EPA estimated costs for an additional one-stage chemical precipitation wastewater treatment system sized to treat only the combustion residual landfill leachate.

Additionally, for leachate treatment, EPA developed cost equations and calculated costs, including equipment and energy, to transport leachate from the landfill site back to the main plant for treatment. The additional pieces of equipment needed to transport the leachate back to the main plant area include leachate transport pumps and stainless steel piping.

Table 9-8 presents the estimated capital and O&M costs on an industry level associated with the treatment of combustion residual landfill leachate. The table also includes the number of plants incurring compliance costs. For plants where EPA calculated costs for the treatment of FGD wastewater and combustion residual landfill leachate in the same system, EPA is presenting the incremental increase in the cost of the treatment system compared to the treatment of only FGD wastewater (i.e., the cost of treating FGD wastewater alone was subtracted from the cost of treating the combined wastestreams). EPA estimated industry-level costs excluding units that are 50 MW or less and oil-fired units. The costs presented in the table represent the compliance costs for those plants expected to be subject to the proposed ELGs; therefore, oil-fired units and units with a capacity of 50 MW or less are not included because they do not need to install the technology basis to meet the new BAT limitations (which are based on the current BPT requirements for these units). See EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units. [U.S. EPA, 2013]

Table 9-8. Estimated Industry-Level Costs for Combustion Residual Leachate Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Number of Plants	Total Capital Cost ($)	Total O&M Cost ($/year)	6-Year Recurring Cost ($/6-year)	10-Year Recurring Cost ($/10-year)
Chemical Precipitation	101	$615,000,000	$58,600,000	$5,630,000	$0
Chemical Precipitation followed by Biological Treatment	101	$931,000,000	$79,100,000	$5,630,000	$0

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2011].

Note: For plants where EPA calculated costs for the treatment of FGD wastewater and combustion residual landfill leachate in the same system, EPA is presenting the incremental increase in the cost of the treatment system compared to the treatment of only FGD wastewater (i.e., the cost of treating FGD wastewater alone was subtracted from the cost of treating the combined wastestreams).

9.9 SUMMARY OF NATIONAL ENGINEERING COSTS

As described in Section 8, EPA evaluated eight regulatory options comprised of various combinations of the technology options considered for each wastestream, as shown in Table 9-9. The Agency estimated the costs associated with steam electric power plants to achieve compliance for each regulatory option under consideration. This section summarizes the total estimated compliance costs associated with each option (see Table 9-10). For each regulatory option, the capital cost, annual operating and maintenance costs, one-time costs, and recurring costs are presented. See the *Regulatory Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for a listing of total annualized costs by regulatory option. All cost estimates in this section are expressed in terms of pre-tax 2010 dollars. The costs presented in the table represent the compliance costs for those plants expected to be subject to the proposed ELGs; therefore, oil-fired units and units with a capacity of 50 MW or less are not included because they do not need to install the technology bases to meet the new BAT limitations (which are based on the current BPT requirements for these units). See EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report for the costs for all generating units. [U.S. EPA, 2013]

Table 9-9. Technology Options and Other Costs Included in the Estimated Compliance Costs for Each Regulatory Option

Wastestream	Technology Option	Regulatory Option							
		1	2	3a	3b	3	4a	4	5
FGD Wastewater	Chemical Precipitation	X	X		X	X	X	X	X
	Biological Treatment		X		X	X	X	X	
	Vapor-Compression Evaporation								X
Fly Ash Transport Water	Dry Fly Ash Handling			X	X	X	X	X	X
Bottom Ash Transport Water	Dry or Closed-loop recycle Bottom Ash Handling						X	X	X
Leachate	Chemical Precipitation							X	X
Gasification Wastewater	Vapor-Compression Evaporation	X	X	X	X	X	X	X	X
Flue Gas Mercury Control Wastes	Dry Handling			X	X	X	X	X	X
Nonchemical Metal Cleaning Wastes	Chemical Precipitation	X	X	X	X	X	X	X	X
Other Costs Not Specific to Wastestream									
	Solids Transportation	X	X	X	X	X	X	X	X
	Solids Disposal	X	X	X	X	X	X	X	X
	Impoundment Operation	X	X	X	X	X	X	X	X
	Compliance Monitoring	X	X		X	X	X	X	X

Table 9-10. Cost of Implementation by Regulatory Option [In millions of pre-tax 2010 dollars]

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One Time Costs	Recurring Costs			
					3-year	5-year	6-year	10-year
1	116	$1,450	$194	$0	$0	$0	$10	($33)
3a	66	$398	$177	$0	$0	$0	$0	($21)
2	116	$2,499	$257	$0	$0	$0	$10	($33)

Table 9-10. Cost of Implementation by Regulatory Option [In millions of pre-tax 2010 dollars]

Regulatory Option	Number of Plants	Capital Cost	Annual O&M Cost	One Time Costs	Recurring Costs			
					3-year	5-year	6-year	10-year
3b	80	$998	$244	$0	$0	$0	$1	($26)
3	155	$2,897	$434	$0	$0	$0	$10	($54)
4a	200	$5,478	$689	$0.3	$1	$38	$10	($90)
4	277	$8,011	$988	$0.6	$28	$65	$16	($137)
5	277	$11,755	$1,753	$0.6	$28	$65	$19	($137)

The compliance costs above account for unit retirements, repowerings and conversions that have been announced by companies and are scheduled to occur by 2014, based on information obtained by EPA as of August 2012. But they do not reflect additional planned unit retirements, repowerings, and conversions that have been announced since August 2012, nor do they reflect announced retirements, repowerings, and conversions that are scheduled to occur by 2022. (See DCN SE02033, "Changes to Industry Profile for Steam Electric Generating Units Updates"). EPA estimates that accounting for these additional changes would reduce the total annualized compliance costs for the rule, which are presented in the *Regulatory Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*. For example, EPA estimated that total pre-tax annualized compliance costs for Option 3 would go from $561.3 million to $532.8 million (5 percent reduction), whereas costs for Option 4 would go from $1,373.2 million to $1,252.9 million (9 percent reduction). EPA expects that similar levels of reductions would be seen in the capital and O&M engineering compliance costs based on these changes.

9.10 COMPLIANCE COSTS FOR NEW SOURCES

EPA evaluated the expected costs of compliance for new sources. The construction of new generating units may occur at an existing power plant or at a new plant construction site.

The incremental cost associated with complying with the proposed NSPS and PSNS options will vary depending on the types of processes, wastestreams, and waste management systems that would have been installed in the absence of the proposed new source requirements. EPA estimated capital and O&M costs for eight different scenarios that represent the different types of operations that are present at existing power plants or are typically included at new power plants. These scenarios captured differences in the following characteristics:

- Plant status (i.e., Greenfield versus existing plant);
- Presence/capacity of on-site impoundments;
- Presence/capacity of on-site landfills;
- Type of FGD system in service;
- Bottom ash handling; and
- Combustion residual leachate collection and handling.

While EPA evaluated eight different scenarios, EPA determined that two of the scenarios best represent the conditions that will be present at new sources. One scenario reflects conditions for a Greenfield plant and the other scenario reflects conditions for a new source constructed at an existing plant. EPA selected the scenarios that most resembled current industry practices, based on an evaluation of the industry profile, for use in the NSPS analysis. Table 9-11 identifies the characteristics that were used for these two scenarios.

Table 9-11. NSPS Compliance Cost Scenarios Evaluated for the Proposed Rule

Plant Characteristics	Existing Plant Scenario	Greenfield Plant Scenario
Plant Status	Existing	Greenfield
Presence of On-Site Impoundments	On-site impoundment with no additional capacity.	No on-site impoundment.
Presence of On-Site Landfill	On-site landfill with available capacity.	On-site landfill to be installed.
Type of FGD System	Wet FGD system.	Wet FGD system.
Bottom Ash Handling	Mechanical drag system already planned.	Mechanical drag system already planned.
Combustion Residual Leachate[1]	No leachate collection in the landfill.	Landfill leachate collected and treated with FGD wastewater.

a – Because the Greenfield plant includes leachate collection while the existing plant does not (because leachate at the existing plant would likely be subject to BAT), the costs presented in Table 9-12 are more expensive for the Greenfield plant than for the existing plant.

EPA evaluated new source costs for FGD wastewater, bottom ash transport wastewater, and combustion residual leachate. Because the current Steam Electric NSPS ELGs already require zero discharge for fly ash transport wastewater, EPA did not calculate new source costs for fly ash. Additionally, because the technology bases for gasification wastewater, flue gas mercury control wastewater, and nonchemical metal cleaning wastes are already standard industry practices, EPA did not calculate new source costs for these wastestreams.

Additionally, EPA determined that the majority of plants installing bottom ash handling systems in the last 10-25 years are installing dry handling systems (approximately 80 percent). Therefore, EPA determined new source incremental compliance costs for dry bottom ash handling would be zero.

In addition to calculating the compliance costs for these two different scenarios, EPA also evaluated the costs for three different model-sized generating units (i.e., small, medium, and large generating units). Table 9-12 presents the estimated capital and O&M costs for each scenario and each model plant size. The estimated incremental compliance costs for each of scenarios evaluated by EPA is included in the memorandum entitled “New Source Performance Standards (NSPS) Costing Methodology.”

Table 9-12. Estimated Industry-Level NSPS Costs

Regulatory Option[a]	Small Unit (350 MW) Total Capital Cost ($)	Small Unit (350 MW) Total O&M Cost ($/year)	Medium Unit (600 MW) Total Capital Cost ($)	Medium Unit (600 MW) Total O&M Cost ($/year)	Large Unit (1,300 MW) Total Capital Cost ($)	Large Unit (1,300 MW) Total O&M Cost ($/year)
Greenfield Plant						
1	[b]	[b]	[b]	[b]	[b]	[b]
2	12,900,000	1,110,000	15,400,000	1,550,000	24,600,000	2,860,000
3	12,900,000	1,110,000	15,400,000	1,550,000	24,600,000	2,860,000
4	13,500,000	1,379,281	19,400,000	2,010,000	26,900,000	3,820,000
5	38,200,000	3,850,000	43,500,000	5,840,000	61,500,000	11,700,000
Existing Plant						
1	[b]	[b]	[b]	[b]	[b]	[b]
2	12,900,000	1,110,000	15,400,000	1,550,000	24,600,000	2,860,000
3	12,900,000	1,110,000	15,400,000	1,550,000	24,600,000	2,860,000
4	12,900,000	1,110,000	15,400,000	1,550,000	24,600,000	2,860,000
5	33,800,000	2,850,000	39,000,000	4,280,000	56,300,000	8,530,000

Source: [ERG, 2013b]

Note: Costs are rounded to three significant figures.

Note: All costs are indexed to 2010 dollars using RSMeans Historical Cost Indices [RSMeans, 2011].

a – EPA did not evaluate Regulatory Option 3a for NSPS because the current ELGs already have a zero discharge standard for NSPS. EPA did not evaluate Regulatory Option 3b for NSPS because EPA does not have data regarding future new source plant-level wet scrubbed capacity at existing plants. EPA also did not evaluate Regulatory Option 4a for NSPS because, as is the case for Options 4 and 5, there are no incremental NSPS costs for bottom ash. Therefore, the costs associated with Option 4a would be equal to Option 3.

b – The NSPS costs for Regulatory Option 1 have been withheld to protect confidential business information.

9.11 REFERENCES

1. HPD. 2009. Communications between Name, HPD and Sarah Holman, Eastern Research Group, Inc. RE: MVC Costs." (17 February). DCN SE01025.
2. Eastern Research Group (ERG). 2013a. Memorandum to the Record. "Flue Gas Desulfurization Future Profile Sensitivity Analysis." (29 January). DCN SE01989.
3. Eastern Research Group (ERG). 2013b. Memorandum to the Steam Electric Rulemaking Record: New Source Performance Standards (NSPS) Costing Memorandum. (19 April). DCN SE02130.
4. Eastern Research Group (ERG). 2013c. Memorandum to the Rulemaking Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Options 3a and 3b. (19 April). DCN SE03881.
5. Eastern Research Group (ERG). 2013d. Steam Electric Technical Questionnaire Database ("Steam Electric Survey"). (19 April). DCN SE01958.
6. RSMeans. 2011. Building Construction Cost Data, 69th Edition.
7. U.S. DOE. 2011. U.S. Department of Energy, Energy Information Administration (EIA). Electric Power Annual 2009. Washington, D.C. (January). DCN SE02023.
8. U.S. Department of Labor, Bureau of Labor Statistics. 2010. Occupational Employment Statistics: May 2009 National Occupational Employment and Waste Estimates, United States. Washington, D.C. (May). DCN SE02024.
9. U.S. EPA, Office of Resource Conservation and Recovery (ORCR). 2010. Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry. Washington, D.C. (April). DCN SE03168.
10. U.S. EPA. 2013. Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category Report. (19 April). DCN SE01957.

SECTION 10
POLLUTANT LOADINGS AND REMOVALS

This section discusses annual pollutant loadings and removal estimates for the steam electric industry for each proposed regulatory option. EPA estimated the pollutant loadings and removals from existing steam electric power plants to evaluate the effectiveness of the treatment technologies, estimate benefits gained from removing pollutants discharged from plants, and evaluate the cost-effectiveness of the regulatory options in reducing the pollutant loadings. EPA defined baseline and post-compliance pollutant loadings as follows:

- *Baseline Loadings*. Pollutant loadings, in pounds per year, in steam electric wastewater being discharged to surface water or through publicly owned treatment works (POTWs) to surface water.
- *Post-Compliance Loadings*. Estimated pollutant loadings, in pounds per year, in steam electric wastewater after implementation of the proposed rule; these are also referred to as treated loadings. EPA calculated these loadings assuming that all steam electric power plants would operate wastewater treatment and pollution prevention technologies equivalent to the technology bases for the regulatory option.
- *Pollutant Removals*. The difference between the baseline loadings and post-compliance loadings for each regulatory option.

Some aspects of the proposed ELGs (e.g., applicability changes) would likely not lead to a change in pollutant loadings to complying plants. Other aspects of the proposed ELGs would likely lead to a change in pollutant loadings for a subset of complying plants. These plants generally generate the wastestreams for which EPA is proposing new limitations or standards. This section describes the detailed pollutant loadings evaluation EPA performed for these plants that are likely to achieve a reduction in pollutant loadings associated with the regulatory options evaluated for the proposed ELGs. Specifically, EPA determined baseline and post-compliance pollutant loadings for the following wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual landfill leachate, gasification wastewater, and flue gas mercury control wastewater.

The currently operating gasification generating units operate vapor-compression evaporation systems (i.e., the technology basis for the preferred options); therefore, EPA determined that the baseline loadings are equal to the post-compliance loadings. Similarly, plants currently manage their flue gas mercury control wastes so there is no pollutant discharge to surface waters; therefore, the baseline loadings for these wastewaters are also equal to the post-compliance loadings. Additionally, because nonchemical metal cleaning wastes are already subject to the proposed BAT limitations, based on the current BPT standard (as described in Section 8.1.3, and because EPA is proposing to exempt from limitations and standards any nonchemical metal cleaning wastes currently generated and authorized for discharge without copper and iron limits, EPA finds that the baseline loadings are equal to the post-compliance loadings. Therefore, the remainder of this section applies to FGD wastewater, fly ash transport water, bottom ash transport water, and combustion residual landfill leachate.

10.1 GENERAL METHODOLOGY FOR ESTIMATING POLLUTANT REMOVALS

For each plant discharging an evaluated wastestream (i.e., FGD wastewater, ash transport water, and combustion residual leachate), EPA calculated plant-level pollutant removals for each of the technology options presented in Section 8. For example, for any plant discharging FGD wastewater, EPA calculated both a baseline loading and post-compliance loadings associated with each technology basis (i.e., one-stage chemical precipitation, one-stage chemical precipitation with biological treatment, and one-stage chemical precipitation with vapor-compression evaporation). On a plant-level basis, EPA calculates baseline loadings by multiplying the average pollutant concentration in the discharge by the plant-specific wastewater discharge flow rate to generate the mass of pollutant discharged per year, in pounds/year.

EPA used sampling data gathered through its sampling program described in Section 3, as well as publicly available sources, to characterize the baseline loading and post-compliance loading concentrations for each evaluated wastestream. Section 10.2 presents the data sources and average discharge pollutant concentrations for baseline and each of the technology options associated with the evaluated wastestreams.

Next, for each evaluated wastestream discharged by a specific plant, EPA used data from the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey) to determine the plant's discharge flow rate. In cases where survey data were insufficient, EPA developed a methodology for estimating flow rates. Section 10.3 provides details on these wastewater flow rates.

EPA calculated baseline pollutant loadings and post compliance treatment loadings for each plant discharging an evaluated wastestream using the plant-specific wastewater flow for the wastestream and average pollutant concentration of the specific wastestream in the following equation:

$$\text{Loading}_{\text{pollutant}}\left(\frac{\text{lbs}}{\text{yr}}\right) = \text{FlowRate}\left(\frac{\text{gallons}}{\text{yr}}\right) \times \text{Conc}_{\text{pollutant}}\left(\frac{\text{mg}}{\text{L}}\right) \times \left(\frac{2.20462\ \text{lb}}{10^6\ \text{mg}}\right) \times \left(\frac{1000\ \text{L}}{264.17\ \text{gallons}}\right)$$

Where:

$\text{Loading}_{\text{pollutant}}$	=	The loadings from a specific pollutant discharged directly to surface water, in pounds per year.
FlowRate	=	The flow rate of the wastestream being discharged, in gallons per year.
$\text{Conc}_{\text{pollutant}}$	=	The average concentration of a specific pollutant present in the wastestream, in milligrams per liter.

EPA identified several plants that report transferring wastewater to a POTW rather than discharging directly to surface water. For these plants, EPA adjusted the baseline loadings to account for pollutant removals expected from POTWs for each analyte. For each POC, Table 10-1 provides the percent removals expected from well-operated POTWs as reported in the *Memo to the 2006 Effluent Guidelines Program Plan Docket* [ERG, 2005]. For any plant identified as discharging a wastestream to a POTW, EPA used the calculated baseline loadings and the values shown in Table 10-1 to calculate the amount of pollutant discharged from the POTW to surface water according to the following equation:

$$\text{Loading}_{\text{pollutant\_indirect}}\left(\frac{\text{lbs}}{\text{yr}}\right)=\text{Loading}_{\text{pollutant}}\left(\frac{\text{lbs}}{\text{yr}}\right)\times(1\text{-POTWRemoval})$$

Where:

$\text{Loading}_{\text{pollutant\_indirect}}$	=	The loadings from a specific pollutant that is transferred to a POTW prior to discharge, in pounds/year.
$\text{Loading}_{\text{pollutant}}$	=	The loadings from a specific pollutant if it were discharged directly, in pounds/year.
POTWRemoval	=	The estimated percentage of the pollutant loading that will be removed by a POTW.

In addition to expressing pollutant loadings in pounds of pollutant discharged per year, EPA uses toxic weighting factors (TWFs) to account for differences in toxicity across pollutants.[85] EPA calculated a toxic-weighted pound equivalent (TWPE) value for each pollutant discharged to compare mass loadings of different pollutants based on their toxicity. To perform this comparison, EPA multiplied the mass loadings of pollutant in pounds/year by the pollutant-specific TWF to derive a "toxic-equivalent" loading (lb-equivalent/yr), or TWPE.[86] Section 10.4 discusses the wastestream mass loading (i.e., unweighted loadings) and TWPE loadings in more detail.

Table 10-1. POTW Removals

Analyte	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	NA
Boron	NA
Cadmium	90.1%
Calcium	NA

[85] A list of pollutant-specific TWF values is located in the *Toxic Weighting Factor Development in Support of CWA 304(m) Planning Process* [U.S. EPA, 2004]. EPA has developed TWFs for more than 1,900 pollutants based on aquatic life and human health toxicity data, as well as physical/chemical property data.

[86] If discharged to a POTW, EPA adjusted the TWPE to account for POTW removals, as described above.

Table 10-1. POTW Removals

Analyte	Median POTW Removal Percentage
Chemical Oxygen Demand	NA
Chloride	NA
Chromium	80.3%
Chromium (VI)	NA
Cobalt	10.2%
Copper	84.2%
Cyanide, Total	NA
Iron	NA
Lead	77.5%
Magnesium	NA
Manganese	40.6%
Mercury	90.2%
Molybdenum	NA
Nickel	51.4%
Nitrate Nitrite as N	90.0%
Nitrogen, Kjeldahl	NA
Phosphorus, Total	NA
Selenium	34.3%
Silver	88.3%
Sodium	NA
Sulfate	NA
Thallium	53.8%
Tin	NA
Titanium	NA
Total Dissolved Solids	NA
Total Suspended Solids	NA
Vanadium	8.3%
Zinc	79.1%

Source: Memo to 2006 Effluent Guidelines Program Plan Docket [ERG, 2005].

NA – Not applicable.

10.2 WASTESTREAM POLLUTANT CHARACTERIZATION AND DATA SOURCES

As discussed earlier, loadings calculations require pollutant concentrations to determine the mass pollutant loadings. EPA used a variety of data sources to generate characterization data for each evaluated wastestream. For each wastestream, EPA excluded all pollutants that were not measured above the quantitation limit in all of the samples representing the baseline effluent discharges for that specific wastestream. Therefore, if a pollutant was measured above the quantitation limit at least once in the baseline effluent concentration dataset, that pollutant was included in the loadings analysis. EPA generated a separate set of characterization data for baseline and each post-compliance technology basis. Section 10.2.1, Section 10.2.2, and Section 10.2.3 present the data sources and characterization for FGD wastewater, ash transport water, and combustion residual leachate, respectively.

10.2.1 FGD Wastewater Characterization

As described in Section 8, EPA is considering three technologies as the basis of proposed discharge requirements for FGD wastewater: one-stage chemical precipitation, one-stage chemical precipitation with biological treatment, and one-stage chemical precipitation with vapor-compression evaporation. Table 10-2 summarizes the concentration data sets that were included in the baseline and post-compliance FGD loadings analysis and their sources. EPA performed the following review, made substitutions, as appropriate, and performed the following analyses with the sampling data results, where appropriate, prior to using them in the technology option loadings calculations:[87]

- J-Values and Nondetects: The laboratories performing the metals analyses provided all the analytical results that were measured above the sample-specific method detection limit (MDL). Therefore, the laboratory results include values flagged with a "J" indicator (i.e., results measured above the method detection limit, but below the quantitation limit). EPA did not use the "J-values" in the loadings calculations. EPA treated all results that were less than the quantitation limit (i.e., J-values and nondetects below the method detection limit) as half the sample-specific quantitation limit for all analytes.
- Field Blank Analysis: EPA compared the sample results from a specific sampling point to the field blank results for the same sampling point, on the specific day of sample collection. For the purpose of the loadings calculations, EPA made the following assumptions based on the results of this field blank analysis:

  - If the sample result was less than five times the field blank result, then the sample result was treated as a nondetect;
  - If the sample result was between five and 10 times the field blank result, then the sample result was flagged and handled as a qualified value; and
  - If the sample result was greater than 10 times the field blank result, then the sample result was unchanged.
  - Note: EPA used field blank results measured above the quantitation limit for this analysis. J-values associated with field blanks samples were not used.

- Duplicate Sample Results: EPA averaged the results from each duplicate sample with the results of its original sample. EPA made the following assumptions when averaging the duplicate results:

[87] Only EPA sampling activities collected and analyzed field blank and duplicate samples. EPA CWA 308 sampling program did not include duplicate sample analysis therefore, only the field blank analysis was conducted on this data set. The plant provided self-monitoring data included no field blank or duplicate samples.

- If one value was quantified and the other value was not quantified above the quantitation limit, then EPA used one-half the sample-specific quantitation limit for the non-quantified result in calculating the average;
- If both values were not quantified above the sample-specific quantitation limit, then EPA used one-half the quantitation limit for both non-quantified results in calculating the average; and
- Both qualified and unqualified data were used in the calculation.

Table 10-2. Data Sets Used in the FGD Loadings Calculation

Plant Name	Source of Data Set	Wastestreams Represented in Data Set [a]
Progress Energy Carolinas' Roxboro Steam Electric Plant (Roxboro)	Monitoring data provided by plant	Settling impoundment effluent
Duke Energy's Miami Fort Station (Miami Fort)	EPA Sampling	Chemical precipitation effluent
	EPA CWA 308 Sampling	Chemical precipitation effluent
RRI Energy's Keystone Generating Station (Keystone)	EPA Sampling	Chemical precipitation effluent
	EPA CWA 308 Sampling	Chemical precipitation effluent
Allegheny Energy's Hatfield's Ferry Electric Plant (Hatfield's Ferry)	EPA Sampling	Chemical precipitation effluent
	EPA CWA 308 Sampling	Chemical precipitation effluent
Duke Energy Carolinas' Belews Creek Steam Station (Belews Creek)	EPA Sampling	Biological treatment effluent
	EPA CWA 308 Sampling	Biological treatment effluent
	Monitoring data provided by plant	Biological treatment effluent
Duke Energy Carolinas' Allen Steam Station (Allen)	EPA Sampling	Biological treatment effluent
	EPA CWA 308 Sampling	Biological treatment effluent
	Monitoring data provided by plant	Biological treatment effluent
Enel Brindisi	EPA Sampling	Vapor-Compression Evaporation Effluent

a -The three plants with data used for chemical precipitation effluent characterization operate one-stage chemical precipitation systems.

Note: EPA excluded data from the We Energies' Pleasant Prairie Power Plant (Pleasant Prairie) in the loadings calculation because the Pleasant Prairie FGD wastewater treatment system consists of a two-stage chemical precipitation system, which is more advanced than the one-stage chemical precipitation system used as the bases for the chemical precipitation technology option. In addition, EPA excluded data from the Mirant Mid-Atlantic, LLC's Dickerson Generating Station (Dickerson) in the loadings calculation because the Dickerson plant was not adding organosulfide chemicals to the wastewater treatment system at the time of sampling. The plant also experienced frequent shutdowns, wastewater treatment upsets, and the treatment system is not designed to remove selenium.

Each of the following sections presents the characterization data set used to calculate mass and TWPE loadings for each option, starting with the baseline characterization.

10.2.1.1 Baseline FGD Wastewater Loading Characterization

As discussed in Section 9, EPA identified 117 plants that operate wet FGD systems and discharge FGD wastewater. For the FGD dischargers, EPA calculated baseline loadings by assigning pollutant concentrations based on the type of treatment system currently in place at the plant. EPA assigned treatment in place for this wastewater to one of four classes of treatment: surface impoundment, chemical precipitation, biological treatment, and vapor-compression evaporation. As discussed in Section 9, EPA used survey data to determine the baseline FGD wastewater treatment in place. Based on survey responses, EPA categorized 46 plants as operating a treatment system more advanced than a surface impoundment:

- Forty plants operate a one-stage chemical precipitation system;
- Five plants operate a biological treatment system;[88] and
- One plant operates a vapor-compression evaporation system.[89]

EPA categorized all plants not operating one of these three types of treatment systems as impoundment systems in the baseline loadings calculations. While some of these plants may operate a system that is not an impoundment, EPA determined that these other systems are typically only solids removal systems that do not include hydroxide or sulfide precipitation (e.g., clarifier with polymer addition). The operation of these types of system are effective at removing solids and metals in the particulate phase, but do not achieve removals of dissolved solids, similar to the operation of an impoundment.

As discussed in Section 7.1.1, surface impoundments use gravity to remove particulates from wastewater, reducing the amount of total suspended solids (TSS) and particulate forms of other specific pollutants in the wastewater. EPA's sampling program collected and analyzed the untreated FGD wastewater of seven steam electric power plants operating wet FGD systems that use either chemical precipitation or chemical precipitation followed by biological treatment to treat the FGD wastewater (see Section 3.4 for a description of these sampling activities and plants). Based on analytical data for the untreated FGD wastewater at these sampled plants, EPA estimated the effluent concentration from a surface impoundment by assuming that a surface impoundment will remove most of the particulate phase metals, but will not remove dissolved metals from the wastewater.[90] EPA calculated proxy values representing impoundment effluent concentrations for each analyte using the data for each of these seven EPA sampled plants. EPA also obtained surface impoundment effluent data from a steam electric power plant that treats only FGD wastewater in the impoundment. EPA averaged the surface impoundment data along with the estimated impoundment effluent concentrations from the seven sampled plants for each analyte to generate an average effluent concentration data set for FGD surface impoundments based on the eight plants. Table 10-3 presents the average characterization data used to calculate

[88] There are six plants currently operating biological treatment system, but at the time the costs and loadings were developed, EPA had only identified five plants with biological treatment systems. Therefore, only five of the six plants were identified as having biological treatment in place for these analyses.

[89] There are two plants currently operating vapor-compression evaporation systems, but at the time the costs and loadings were developed, EPA had only identified one plant with a vapor-compression evaporation system. Therefore, only one of the two plants were identified as having vapor-compression treatment in place for these analyses.

[90] The methodology used to estimate settling impoundment effluent concentrations is presented in detail in the *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category* Report [U.S. EPA, 2013].

baseline loadings for plants currently treating FGD wastewater in a surface impoundment prior to discharge.

Approximately 40 percent of plants discharging FGD wastewater use a more advanced treatment system. For those plants currently operating a one-stage chemical precipitation system, biological treatment system, or vapor-compression evaporation system, EPA used the concentration data sets associated with the post-compliance technology options to calculate baseline loadings. Section 10.2.1.2 discusses the characterization of one-stage chemical precipitation systems. Sections 10.2.1.3 and 10.2.1.4 discuss the characterization of one-stage chemical precipitation systems with biological treatment or with vapor-compression evaporation systems, respectively.

Table 10-3. Average Effluent Pollutant Concentrations for FGD Surface Impoundments

Analyte	Unit	Average Concentration
Classicals		
Ammonia	ug/L	NA
Nitrate Nitrite as N	ug/L	67,300
Nitrogen, Kjeldahl	ug/L	NA
Biochemical Oxygen Demand	ug/L	NA
Chemical Oxygen Demand	ug/L	418,000
Chloride	ug/L	7,320,000
Sulfate	ug/L	1,240,000
Cyanide, Total	ug/L	1,190
Total Dissolved Solids	ug/L	28,600,000
Total Suspended Solids	ug/L	27,900
Phosphorus, Total	ug/L	404
Total Metals		
Aluminum	ug/L	2,080
Antimony	ug/L	13
Arsenic	ug/L	6.8
Barium	ug/L	303
Beryllium	ug/L	1.9
Boron	ug/L	243,000
Cadmium	ug/L	112
Calcium	ug/L	2,050,000
Chromium	ug/L	18
Chromium (VI)	ug/L	NA
Cobalt	ug/L	183
Copper	ug/L	21
Iron	ug/L	1,510

Table 10-3. Average Effluent Pollutant Concentrations for FGD Surface Impoundments

Analyte	Unit	Average Concentration
Lead	ug/L	4.7
Magnesium	ug/L	3,370,000
Manganese	ug/L	93,100
Mercury	ug/L	5.6
Molybdenum	ug/L	125
Nickel	ug/L	878
Selenium	ug/L	1,110
Silver	ug/L	0.93
Sodium	ug/L	276,000
Thallium	ug/L	13
Tin	ug/L	100
Titanium	ug/L	27
Vanadium	ug/L	16
Zinc	ug/L	1,390

Source: [ERG, 2012a – 2012i]; [NCDENR, 2011].

Note: Concentrations are rounded to three significant figures.

NA – Not applicable.

10.2.1.2 Baseline and Post Compliance One-Stage Chemical Precipitation Pollutant Characterization

As part of the sampling activities described in Section 3, EPA identified and collected data from seven plants operating chemical precipitation systems, sometimes in conjunction with other technologies, such as biological treatment. The specific operating characteristics of the chemical precipitation treatment systems varied. EPA conducted an engineering review of the data and identified three systems operating consistently with the one-stage chemical precipitation technology basis. These three plants operate one-stage chemical precipitation systems that include the addition of organosulfide.

The treatment systems at these plants have similar operations; however, the plants do have varying configurations and operating characteristics, such as thickeners, filter presses, sand filters, and retention time. Each of these systems were designed and are operated to remove suspended solids and dissolved metals from the FGD wastewater to achieve a similar level of pollutant discharge. The systems are sized to handle a specific flow rate of FGD wastewater, which means that the sizes of the tanks were designed to allow for the residence time required for settling and/or reactions to occur to achieve effluent concentrations meeting the plant's permit limits.

To calculate the pollutant concentrations for the one-stage chemical precipitation technology option, EPA first calculated an average concentration for each analyte using only the four-day EPA sampling data for each plant for which data were available. EPA included only total concentrations except for hexavalent chromium, which is analyzed only as a dissolved constituent. EPA then calculated an average concentration for each analyte at each plant by using the four CWA 308 monitoring data results along with the average of the four-day EPA sampling data (i.e., treating these as five results and calculating the average).

Using the average concentrations from the three plants, as calculated above, EPA then calculated an overall average concentration for each of the analytes shown in Table 10-4. EPA used this average concentration to calculate the post-compliance loadings that would be discharged by plants that currently operate surface impoundments if they were to install the chemical precipitation technology. EPA also used the average concentrations presented in Table 10-4 to calculate the baseline loadings for any plant currently operating a chemical precipitation treatment system as FGD wastewater treatment.

As explained above, the values presented in Table 10-4 reflect three plants identified as operating consistently with the technology basis and EPA has applied these values to all plants that operate chemical precipitation systems as their baseline concentrations. As discussed in Section 10.2.1.1, EPA classified 38 other plants as operating chemical precipitations systems. However, these 38 plants do not operate their chemical precipitation system in the same manner as the technology basis (or have all the components included in the technology basis) and would likely discharge greater pollutant concentrations than the systems reflecting the technology basis. Further, for these 38 plants that operate chemical precipitation systems that are not equivalent to the technology basis, the baseline and post-compliance loadings are identical and EPA calculates no removals for these plants, even though these plants are being assessed compliance costs to upgrade the system to operate similarly to the technology basis.

Table 10-4. Average Effluent Pollutant Concentrations for One-Stage Chemical Precipitation System

Analyte	Unit	Average Concentration
Classicals		
Ammonia	ug/L	8,120
Nitrate Nitrite as N	ug/L	67,300
Nitrogen, Kjeldahl	ug/L	27,000
Biochemical Oxygen Demand	ug/L	3,130
Chemical Oxygen Demand	ug/L	418,000
Chloride	ug/L	8,940,000
Sulfate	ug/L	5,980,000
Cyanide, Total	ug/L	1,190
Total Dissolved Solids	ug/L	23,100,000
Total Suspended Solids	ug/L	6,560
Phosphorus, Total	ug/L	404
Total Metals		
Aluminum	ug/L	155

Table 10-4. Average Effluent Pollutant Concentrations for One-Stage Chemical Precipitation System

Analyte	Unit	Average Concentration
Antimony	ug/L	5.0
Arsenic	ug/L	4.5
Barium	ug/L	163
Beryllium	ug/L	1.00
Boron	ug/L	279,000
Cadmium	ug/L	3.8
Calcium	ug/L	2,330,000
Chromium	ug/L	9.1
Chromium (VI)	ug/L	5.3
Cobalt	ug/L	10
Copper	ug/L	2.0
Iron	ug/L	127
Lead	ug/L	1.00
Magnesium	ug/L	3,340,000
Manganese	ug/L	13,600
Mercury	ug/L	0.17
Molybdenum	ug/L	215
Nickel	ug/L	5.6
Selenium	ug/L	455
Silver	ug/L	1.00
Sodium	ug/L	420,000
Thallium	ug/L	8.6
Tin	ug/L	100
Titanium	ug/L	10
Vanadium	ug/L	15
Zinc	ug/L	18

Source: [ERG, 2012c]; [ERG, 2012f]; [ERG, 2012g]; [ERG, 2012i].

Note: Concentrations are rounded to three significant figures.

10.2.1.3 Baseline and Post-Compliance One-Stage Chemical Precipitation with Biological Treatment Characterization

EPA identified and collected data from two plants operating chemical precipitation systems in conjunction with biological treatment systems that represent the biological treatment technology option for the proposed rule. After conducting an engineering review of the data, EPA determined that both plants operate systems consistent with the one-stage chemical precipitation with biological treatment technology option. Both of the plants sampled operate chemical precipitation systems followed by anoxic/anaerobic biological treatment systems specifically designed for selenium removal. EPA used the data from both plants to represent treatment performance of a one-stage chemical precipitation system with biological treatment system; however, these two plants do not fully represent the technology option because neither plant currently uses sulfide precipitation in the chemical precipitation system. Therefore, these two plants likely do not demonstrate mercury (and other metals) effluent concentrations as low as could be achieved by the one-stage chemical precipitation (with sulfide precipitation) followed by a biological treatment system that forms the basis of the option (see Section 7 for complete description).

EPA has multiple sets of data for these two plants including EPA sampling data, CWA 308 sampling data, and self-monitoring data to calculate pollutant loadings associated with this technology option. To calculate the average pollutant concentrations for the biological treatment system technology option, EPA first compared long-term self-monitoring data provided by the plants to EPA sampling data and CWA 308 monitoring data to determine which analytes were represented in different sets of data. In cases where an analyte was not represented in the long-term self-monitoring data, but was represented in the EPA sampling and CWA 308 monitoring data, EPA averaged the four-day EPA sampling results and then combined that average with the four CWA 308 monitoring data results (i.e., treated them as five results) for each plant. EPA then averaged these five results to calculate an overall plant-level average concentration for each of those analytes. In cases where an analyte was represented in the long-term self-monitoring data provided by the plant, the EPA sampling, and the CWA 308 monitoring data, EPA averaged all sample results to calculate a plant-level average concentration for each analyte. When combining the industry self-monitoring data with EPA's sampling results (both four-day EPA sampling and CWA 308 monitoring), there were some instances of overlap with two sample results occurring on the same day. In these cases, the two results were averaged together to calculate one average concentration for each day of sampling before calculating an average concentration for each analyte.

Using the average concentrations from the two BAT plants, EPA calculated an overall average concentration for each analyte, which is presented in Table 10-5. EPA used this average concentration to calculate the post-compliance loadings that would be discharged by plants currently operating surface impoundments or chemical precipitation systems if they were to install all components of the biological technology option. EPA also used the average concentrations presented in Table 10-5 to calculate the baseline loadings for any plant currently operating chemical precipitation and a biological treatment system as FGD wastewater treatment.

The average concentration used to calculate baseline and post-compliance loadings for the chemical precipitation and a biological treatment system technology basis, presented in Table 10-5, is based on two plants identified as operating consistently with the technology basis. As discussed in Section 10.2.1.1, EPA classified five plants as operating biological treatment systems.[91] For each plant classified as a baseline biological treatment system EPA calculated the baseline loadings using the average concentration presented in Table 10-5. Two of these plants

[91] There are six plants currently operating biological treatment system, but at the time the costs and loadings were developed, EPA had only identified five plants with biological treatment systems. Therefore, only five of the six plants were identified as having biological treatment in place for these analyses.

do not operate consistently with the technology basis and likely discharge greater pollutant concentrations than the system reflecting the technology basis.[92] Further, for these two plants, the baseline and post-compliance loadings are identical and show no additional removals even though these plants are being assessed compliance costs to upgrade the system to achieve the technology basis.

Table 10-5. Average Effluent Pollutant Concentrations for One-Stage Chemical Precipitation System with Biological Treatment

Analyte	Unit	Average Concentration
Classicals		
Ammonia	ug/L	8,750
Nitrate Nitrite as N	ug/L	79
Nitrogen, Kjeldahl	ug/L	12,100
Biochemical Oxygen Demand	ug/L	1,740
Chemical Oxygen Demand	ug/L	156,000
Chloride	ug/L	6,720,000
Sulfate	ug/L	1,380,000
Cyanide, Total	ug/L	74
Total Dissolved Solids	ug/L	14,100,000
Total Suspended Solids	ug/L	8,210
Phosphorus, Total	ug/L	115
Total Metals		
Aluminum	ug/L	155
Antimony	ug/L	2.0
Arsenic	ug/L	4.6
Barium	ug/L	323
Beryllium	ug/L	0.97
Boron	ug/L	125,000
Cadmium	ug/L	2.5
Calcium	ug/L	2,970,000
Chromium	ug/L	2.2
Chromium (VI)	ug/L	3.0
Cobalt	ug/L	10
Copper	ug/L	2.7
Iron	ug/L	302
Lead	ug/L	1.00
Magnesium	ug/L	741,000

[92] Of the total five baseline biological treatment plants, only three are classified as operating consistently with the technology basis.

Table 10-5. Average Effluent Pollutant Concentrations for One-Stage Chemical Precipitation System with Biological Treatment

Analyte	Unit	Average Concentration
Manganese	ug/L	1,960
Mercury	ug/L	0.067
Molybdenum	ug/L	20
Nickel	ug/L	2.6
Selenium	ug/L	5.0
Silver	ug/L	2.3
Sodium	ug/L	46,100
Thallium	ug/L	1.9
Tin	ug/L	100
Titanium	ug/L	10
Vanadium	ug/L	5.0
Zinc	ug/L	4.8

Source: [ERG, 2012a]; [ERG, 2012d]; [ERG, 2012i]; [Duke Energy, 2011a – 2011b].

Note: Concentrations are rounded to three significant figures.

10.2.1.4 Baseline and Post-Compliance One-Stage Chemical Precipitation with Vapor-Compression Evaporation Characterization

EPA conducted an engineering review of the data for the two plants operating vapor-compression evaporation system. Because only one plant matches the technology basis and operates a hydroxide-sulfide chemical precipitation system followed by softening, a brine concentrator, and crystallization system, EPA used data from this plant to represent the technology option.

To calculate the average pollutant concentrations for the vapor-compression evaporation treatment system technology option, EPA first calculated an average concentration by analyte for each of the two wastestreams at the plant (i.e., brine concentrator distillate and crystallizer condensate) using available sampling data (i.e., three-day EPA sampling data). For this plant EPA collected and analyzed only total concentrations; therefore, EPA did not have dissolved concentrations or hexavalent chromium data to use in the analysis.

Using the average concentrations from the two streams (i.e., brine concentrator distillate and crystallizer condensate), EPA calculated an overall average concentration for each analyte, shown in Table 10-6.[93] EPA used this average concentration to calculate the post-compliance loadings that would be discharged by plants currently operating surface impoundments, chemical

[93] EPA used both the brine concentrator distillate and crystallizer condensate streams to calculate the loadings because both wastestreams could be discharged. The vapor-compression system at Brindisi is operated as a zero-discharge system with no wastewater being discharge to surface water or POTW. The plant could choose to discharge both the brine concentrator and the crystallizer condensate streams, together or separately.

precipitation systems, or biological treatment systems if they were to install all components of the vapor-compression evaporation technology option. EPA also used the average concentrations presented in Table 10-6 to calculate the baseline loadings for any plant currently operating chemical precipitation and a vapor-compression evaporation treatment system as FGD wastewater treatment.

Table 10-6. Average Effluent Pollutant Concentrations for One-Stage Chemical Precipitation System with Vapor-Compression Evaporation

Analyte	Unit	Average Concentration
Classicals		
Ammonia	ug/L	24,300
Nitrate Nitrite as N	ug/L	100
Nitrogen, Kjeldahl	ug/L	23,500
Chemical Oxygen Demand	ug/L	10,000
Chloride	ug/L	1,500
Sulfate	ug/L	2,500
Total Dissolved Solids	ug/L	10,800
Total Suspended Solids	ug/L	2,000
Phosphorus, Total	ug/L	25
Total Metals		
Aluminum	ug/L	100
Antimony	ug/L	1.00
Arsenic	ug/L	2.0
Barium	ug/L	10
Beryllium	ug/L	1.00
Boron	ug/L	3,750
Cadmium	ug/L	2.0
Calcium	ug/L	200
Chromium	ug/L	4.0
Cobalt	ug/L	10
Copper	ug/L	2.0
Iron	ug/L	100
Lead	ug/L	1.00
Magnesium	ug/L	200
Manganese	ug/L	10
Mercury	ug/L	0.0103
Molybdenum	ug/L	20
Nickel	ug/L	2.0
Selenium	ug/L	2.0
Silver	ug/L	1.0

Table 10-6. Average Effluent Pollutant Concentrations for One-Stage Chemical Precipitation System with Vapor-Compression Evaporation

Analyte	Unit	Average Concentration
Sodium	ug/L	5,000
Thallium	ug/L	1.0
Tin	ug/L	100
Titanium	ug/L	10
Vanadium	ug/L	5.0
Zinc	ug/L	28.5

Source: [ERG, 2012h].

Note: Concentrations are rounded to three significant figures.

NA – Not applicable.

10.2.2 Ash Transport Water Characterization

During this rulemaking effort, EPA relied on publicly available data sources to characterize the effluent stream from ash impoundments at steam electric power plants; these sources are listed below:

- EPA ash impoundment sampling data from the detailed study [U.S. EPA, 2009];
- Electric Power Research Institute (EPRI) Power Plant Integrated Systems-Chemical Emissions Study (PISCES) Reports [EPRI, 1997-2001];
- Permit application data, as provided by member companies of the Utility Water Act Group (UWAG) [UWAG, 2008]; and
- Development Document for Final Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category, EPA 440-1-82-029, November 1982 (1982 TDD) [U.S. EPA, 1982].

Section 3 provides details regarding each of the four data sources used in the ash impoundment loadings. EPA used information available from each data source to characterize the impoundment/outfall as either a fly ash impoundment, bottom ash impoundment, or combined ash impoundment. For the purposes of this analysis, EPA used the following criteria to make those determinations:

- Fly ash impoundment: An impoundment/outfall that receives fly ash transport water and does not receive bottom ash transport water or any other combustion residual wastes. The impoundment may also receive other types of wastewater (e.g., low volume wastewaters, cooling water).
- Bottom ash impoundment: An impoundment/outfall that receives bottom ash transport water and does not receive fly ash transport water or any other combustion residual wastes. The impoundment may also receive other types of wastewater (e.g., low volume wastewaters, cooling water).

- Combined ash impoundment: An impoundment/outfall that receives both fly ash transport and bottom ash transport water. The impoundment may also receive other types of wastewater (e.g., low volume wastewaters, cooling water).

EPA used the concentration data obtained from these data sources to calculate the average pollutant concentration in fly ash transport water, bottom ash transport water, and combined ash transport water. EPA notes that because the data associated with these impoundments may include other wastestream (e.g., cooling water), the concentrations may be diluted and therefore, may underestimate the pollutant loadings. First, EPA reviewed the data and, as appropriate, made some substitutions to the data sets. EPA set nondetects equal to one-half the quantitation limit for the detailed study sampling data because EPA knew the quantitation limit.[94] For the other (i.e., EPRI, 1982 TDD, and Form 2C) data sets, EPA could not confirm whether the nondetect results were presented as less than the quantitation limit or the method detection limit (or some other value); therefore, EPA set the nondetects equal to the value provided. For each data point, EPA first identified the type of impoundment system the data represents (i.e., fly ash impoundment, bottom ash impoundment, combined ash impoundment). EPA then calculated an average pollutant concentration for each impoundment for which it had data. For example, if a plant had pollutant concentration data for its fly ash impoundment for more than one day, EPA averaged all these data for that specific pollutant to get a single representative value of average concentration of that pollutant in the effluent from the fly ash impoundment. EPA used the same methodology to calculate the average concentration of a pollutant in the effluents from bottom ash impoundments and combined ash impoundments. Some data sources provided only one data point, and therefore, the average is the same as that data point.

After calculating an average concentration for each type of impoundment at the plant-specific level, EPA then calculated an industry-level average pollutant concentration for each type of impoundment for which EPA had data by averaging the plant-level average concentrations for each type of impoundment.[95] Table 10-7 presents the average pollutant concentration for all three types of ash impoundment. EPA used these average concentration data sets to calculate the baseline loadings for discharges from ash impoundments.

The technology option under consideration for both fly ash and bottom ash is dry or closed-loop recycle ash handling. As discussed in Section 7, these systems do not discharge ash transport water; therefore, the average effluent concentration associated with dry or closed-loop recycle ash handling is zero. Because no ash transport water is discharged, the post-compliance discharge loading is zero.

[94] To simplify the discussion, for the purpose of Section 10.2.2 the term "nondetect" is used to refer to both values measured below the quantitation limit and those values measured below the detection limit.

[95] The methodology used to calculate the average concentrations for ash impoundment effluent is presented in the *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category* Report [U.S. EPA, 2013].

Table 10-7. Average Effluent Pollutant Concentration for Ash Impoundment Systems

Analyte	Unit	Average Fly Ash Concentration	Average Bottom Ash Concentration	Average Combined Ash Concentration
Classicals				
Ammonia (as N)	mg/L	0.62	0.24	0.27
Nitrate-Nitrite (as N)	mg/L	2.51	9.65	2.53
Total Kjeldahl Nitrogen	mg/L	0.41	1.36	3.39
Biochemical Oxygen Demand	mg/L	1.5	1	4
Chloride	mg/L	107	53.5	16.4
Sulfate	mg/L	709	1,170	203
Sulfide (as S)	mg/L	1.01	0.51	0.52
Sulfite (as SO3)	mg/L	2	26.7	1.63
Cyanide	mg/L	NA	NA	0.01
Total Dissolved Solids	mg/L	1,362	1,260	262.4
Total Suspended Solids	mg/L	8.06	8.36	13.8
Fluoride	mg/L	NA	NA	0.15
Hexane Extractable Material	mg/L	6.25	2.5	6
Nitrogen, Total Organic (as N)	mg/L	0.65	3.28	0.51
Oil and Grease	mg/L	2.13	3.67	2.83
Silica-Gel Treated Hexane Extractable Material	mg/L	2	NA	2.5
Phosphorus (as P)	mg/L	0.12	0.36	0.28
Total Metals				
Aluminum	mg/L	0.46	0.59	1.11
Antimony	mg/L	0.028	0.093	0.024
Arsenic	mg/L	0.042	0.018	0.064
Barium	mg/L	0.13	0.078	0.2
Beryllium	mg/L	0.003	0.004	0.005
Boron	mg/L	4.67	2.24	1.97
Cadmium	mg/L	0.006	0.008	0.008
Calcium	mg/L	102	186	70.7
Chromium	mg/L	0.017	0.014	0.02
Hexavalent Chromium	mg/L	0.005	0.001	0.012
Cobalt	mg/L	0.014	0.048	0.012
Copper	mg/L	0.042	0.027	0.04
Iron	mg/L	1.81	2.44	0.58
Lead	mg/L	0.03	0.037	0.027
Magnesium	mg/L	18.8	97.3	15.3

Table 10-7. Average Effluent Pollutant Concentration for Ash Impoundment Systems

Analyte	Unit	Average Fly Ash Concentration	Average Bottom Ash Concentration	Average Combined Ash Concentration
Manganese	mg/L	0.041	0.13	0.62
Mercury	mg/L	0.001	0.001	0.002
Molybdenum	mg/L	0.43	0.065	0.14
Nickel	mg/L	0.035	0.13	0.035
Selenium	mg/L	0.035	0.013	0.03
Silica	mg/L	NA	NA	5.93
Silver	mg/L	0.003	0.004	0.008
Sodium	mg/L	298	106	21.3
Thallium	mg/L	0.011	0.12	0.049
Tin	mg/L	0.025	0.34	0.15
Titanium	mg/L	0.008	0.11	0.029
Vanadium	mg/L	0.11	0.01	0.044
Yttrium	mg/L	0.003	0.003	0.003
Zinc	mg/L	0.17	0.094	0.085

Source: [U.S. EPA, 2009]; [U.S. EPA, 1982]; [EPRI, 1997 – 2001]; [UWAG, 2008].

Note: Concentrations are rounded to three significant figures.

NA – Not applicable.

10.2.3 Baseline and Post-Compliance Combustion Residual Leachate Characterization

As described in Section 6, EPA determined that combustion residual impoundments will recycle the leachate back to the impoundment from which it was collected rather than install the technology basis for the discharge requirements. EPA does not expect this recycled impoundment leachate to alter the discharge loadings of the impoundment in anyway. By recycling leachate generated by the impoundment back into the same impoundment no additional pollutants are added to the system (i.e., the surface impoundment). The pollutants contained in the impoundment leachate were previously in the system; adding these pollutants back to the system at the concentrations found in the leachate will not alter the system as a whole. The concentrations of pollutants in the discharge stream will remain at equilibrium. Therefore, EPA finds that baseline and post-compliance pollutant loadings will be the same at baseline and at post-compliance for combustion residual impoundment leachate. Therefore, the remainder of this section only discusses the pollutant concentrations associated with combustion residual landfill leachate.

As described in Section 8, EPA evaluated two technology options for treating combustion residual landfill leachate: one-stage chemical precipitation and one-stage chemical precipitation with biological treatment. EPA used data collected through the Steam Electric Survey to calculate average effluent concentrations for untreated combustion residual landfill leachate.

EPA's Steam Electric Survey required certain plants to collect and analyze samples of landfill leachate and report the results of these analyses. EPA requested these plants to sample any untreated landfill leachate collected from an on-site landfill containing combustion residuals. EPA used all data as provided by the plants in the survey, except for the following:

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

EPA compiled all untreated landfill leachate sampling data reported in the Steam Electric Survey from 26 landfills and split them into groups based on the landfill type (i.e., active or inactive). The responses to the survey included data from 22 active combustion residual landfills and four inactive combustion residual landfills. To determine the industry average concentrations for a pollutant, EPA first averaged all concentration data provided for each individual landfill providing sampling data to calculate a landfill-specific average concentration. EPA then averaged the landfill-specific average concentrations at each plant based on the landfill type (i.e., active or inactive) to get a plant-level average pollutant leachate concentration for each landfill type. EPA then used the average plant-level combustion residual landfill to calculate the average concentrations across all plants. Table 6-10 presents the average concentration for leachate from active and inactive landfills. EPA used these average concentrations to calculate baseline loadings for all plants discharging combustion residual landfill leachate.

As explained in Section 7.4, based on a review of the Steam Electric Survey data regarding the treatment of the combustion residual landfill leachate, EPA did not identify any plants currently operating a chemical precipitation system to treat landfill leachate. Therefore, EPA transferred the limitations and standards from the FGD chemical precipitation system, Because EPA does not have analytical data that represent treated landfill leachate for the technology options being considered, EPA also transferred the FGD chemical precipitation effluent concentrations, identified in Section 10.2.1, to the landfill leachate for the purposes of calculating post-compliance loadings. In cases where the average concentration of the untreated active or inactive combustion residual landfill leachate is less than the FGD treated concentration for the technology option, EPA assumed that the treated concentration was equal to the influent (untreated leachate) average concentration. In this case, EPA did not calculate additional removals of these particular pollutants by the wastewater treatment system.

Table 10-8. Average Pollutant Concentrations Untreated Landfill Leachate

Analyte	Unit	Untreated Active Landfill Concentration	Untreated Inactive Landfill Concentration
Classicals			
Chloride	ug/L	542,000	11,100
Sulfate	ug/L	1,910,000	1,070,000
Total Dissolved Solids	ug/L	3,860,000	1,670,000
Total Suspended Solids	ug/L	41,400	4,210
Total Metals			

Table 10-8. Average Pollutant Concentrations Untreated Landfill Leachate

Analyte	Unit	Untreated Active Landfill Concentration	Untreated Inactive Landfill Concentration
Aluminum	ug/L	5,030	100
Antimony	ug/L	4.6	4.9
Arsenic	ug/L	46	10
Barium	ug/L	57	50
Beryllium	ug/L	1.9	0.47
Boron	ug/L	20,500	3,640
Cadmium	ug/L	2.7	1.9
Calcium	ug/L	481,000	386,000
Chromium	ug/L	4.9	1.6
Cobalt	ug/L	84	3.8
Copper	ug/L	10	1.7
Iron	ug/L	59,000	95
Lead	ug/L	1.4	0.47
Magnesium	ug/L	115,000	33,700
Manganese	ug/L	4,360	355
Mercury	ug/L	1.4	0.01
Molybdenum	ug/L	1,880	995
Nickel	ug/L	69	43
Selenium	ug/L	74	84
Silver	ug/L	0.68	0.42
Sodium	ug/L	327,000	16,700
Thallium	ug/L	1.3	0.96
Tin	ug/L	11	13
Titanium	ug/L	17	15
Vanadium	ug/L	3,240	6.2
Zinc	ug/L	154	58

Source: Steam Electric Survey [ERG, 2013].

Note: Concentrations are rounded to three significant figures.

10.3 WASTEWATER FLOW RATES FOR BASELINE AND POST-COMPLIANCE POLLUTANT LOADINGS

As discussed earlier, EPA used plant-specific wastewater flow rates in the loadings calculations. EPA used information from the Steam Electric Survey to determine which plants discharge each specific wastestream of concern and the amount of wastewater each plant reported discharging. This section provides more detail on EPA's methodology for calculating the specific wastewater flow rates used in the loadings calculations.

10.3.1 FGD Wastewater Flow Rates for Pollutant Loadings

As described in Section 9, EPA used plant-level FGD wastewater flow rates to calculate compliance costs. EPA used the same FGD wastewater flow rates in both the FGD wastewater technology cost modules and the FGD wastewater loadings to ensure consistency between the two estimates.

10.3.2 Ash Transport Water Flow Rates for Pollutant Loadings

EPA used data from the Steam Electric Survey to identify those plants that discharge or have the potential to discharge fly ash or bottom ash transport water. Based on the amount of ash transport water discharged, EPA calculated ash impoundment discharge loadings for each of these plants. EPA first identified all impoundments with ash transport water as an influent stream and an effluent stream that discharges to a surface water or POTW.[96] For each impoundment included in its analysis, EPA identified the flow rate associated with the fly ash transport water, bottom ash transport water, or combined ash transport water. EPA used the following hierarchy to determine the ash transport water flow rates:[97]

- Influent flow rates to the impoundments reported in the pond/impoundment systems section of the Steam Electric Survey;
- Ash transport water flow rates reported in the ash handling section of the survey; or
- Percent contributions of ash transport water to a plant outfall multiplied by the total outfall flow rate reported in the general power plant operations section of the survey.

Because most generating units/ash handling systems do not operate 365 days per year, EPA normalized the ash impoundment discharge flow rates. To do this, EPA calculated the amount of ash transport water transferred to each ash impoundment per year by multiplying the flow rate by the number of days the ash transport water is generated or transferred to the impoundment, depending on which source is being used. EPA divided this yearly ash transport water flow by 365 days per year to calculate a flow rate in gallons per day (gpd) for use in loadings calculations. Using these normalized ash impoundment discharge flow rates, EPA calculated plant-level ash impoundment discharge flow rates for each of the three possible types (fly, bottom, and combined) of ash transport waters.

The ash transport water flow rates used for the loadings analysis is not the same data used to estimate compliance costs for plants to eliminate fly ash or bottom ash transport water. Compliance costs are based on the amount of fly ash or bottom ash generated by specific generating units while baseline and post-compliance loadings are based on the flow rate of ash transport water.

---

[96] As defined in the Steam Electric Survey, impoundments refer to a system of one or more surface impoundments.

[97] The *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category* Report provides more specific detail on the specifics of this hierarchy and EPA's methodology for generating impoundment-specific ash impoundment discharge flow rates [U.S. EPA, 2013].

10.3.3 Combustion Residual Landfill Leachate Flow Rates for Pollutant Loadings

As described in Section 9, EPA used plant-level landfill leachate flow rates to calculate compliance costs. EPA used the same landfill leachate flow rates in both the leachate technology cost modules and the leachate loadings to ensure consistency between the two estimates.

10.4 Baseline and Post-Compliance Pollutant Loadings and TWPE Results

As discussed in Section 10.1, as applicable, EPA multiplied the average pollutant concentrations for each wastestream presented in Section 10.2 with the plant-specific wastewater flow rates presented in Section 10.3 to calculate the amount of pollutant discharged to surface waters for each plant and wastestream. For those plants transferring the wastewater to a POTW, EPA adjusted the loadings to account for additional removals that would take place at the POTW. After calculating these loadings for each plant and wastestream, EPA then calculated the TWPE associated with the pollutant discharges. These calculations were completed for the baseline and post-compliance pollutant loadings for each plant associated with each technology option. Using the plant-level loadings by wastestream, EPA was then able to calculate the baseline and post-compliance loading at the industry level for each wastestream and regulatory option. The following section discusses the specific loadings and TWPE calculations for each wastestream, each of the technology options being considered, and each of the regulatory options evaluated by EPA. The section also presents the industry-level loadings for each wastestream and regulatory option.

10.4.1 FGD Wastewater Loadings and TWPE

EPA calculated plant-specific loadings for each of the technology options considered for FGD wastewater. For baseline loadings, EPA multiplied the plant-specific FGD wastewater discharge flow rate with the average pollutant concentrations that represent the current level of treatment at the plant (i.e., surface impoundment, chemical precipitation, biological treatment, or vapor-compression evaporation). EPA identified two plants transferring FGD wastewater to a POTW. For these two plants, EPA adjusted the baseline loadings to account for pollutant removals associated with POTW treatment.

For the post-compliance loadings associated with the one-stage chemical precipitation technology option, EPA assumed the discharge loadings calculated for plants currently treating their FGD wastewater with a one-stage chemical precipitation system, a biological treatment system, or a vapor-compression evaporation system remain unchanged from baseline. EPA assumed plants with a baseline surface impoundment would install a one-stage chemical precipitation treatment system to meet the effluent requirements associated with this option. EPA calculated post-compliance loadings for these plants using the average concentration data set associated with one-stage chemical precipitation systems, presented in Table 10-4, and plant-specific FGD wastewater flow rates. As described in Section 10.2.1.2, for each plant classified as a baseline chemical precipitation system, EPA used the same chemical precipitation effluent concentrations to calculate the baseline and post-compliance loadings, even if the system is not equivalent to the technology basis. This underestimates the pollutant removals being achieved by the treatment system because EPA calculates no removals for these plants, even though some of these plants are being assessed compliance costs to upgrade the system to operate similarly to the technology basis.

For the post-compliance pollutant loadings associated with the one-stage chemical precipitation treatment system followed by biological treatment technology option, EPA assumed the post-compliance loadings calculated for plants currently treating their FGD wastewater with a biological treatment system or a vapor-compression evaporation system remain unchanged from baseline. EPA assumed plants with a surface impoundment would install a one-stage chemical precipitation system with biological treatment and plants with a one-stage chemical precipitation system (but no biological treatment for selenium removal) would install a biological treatment system to meet the effluent requirements associated with this technology option. EPA calculated the post-compliance loadings for these plants using the average concentration data set associated with one-stage chemical precipitation systems followed by biological treatment, presented in Table 10-5, and plant-specific FGD wastewater flow rates.

For the post-compliance pollutant loadings associated with the one-stage chemical precipitation treatment system followed by vapor-compression evaporation option, EPA assumed the post-compliance loadings calculated for plants currently treating their FGD wastewater with this type of system remain unchanged from baseline. EPA assumed plants with any other current treatment method (i.e., surface impoundment, chemical precipitation, or biological treatment) would install a one-stage chemical precipitation treatment system with vapor-compression evaporation to meet the effluent requirements associated with this technology option. EPA calculated the post-compliance loadings for these plants using the average concentration data set associated with one-stage chemical precipitation systems with vapor-compression evaporation, presented in Table 10-6, and plant-specific FGD wastewater flow rates.

Table 10-9 presents the FGD wastewater loadings at an industry level for baseline and each post-compliance technology basis. The loadings presented in Table 10-9 are based on the oil-fired units and those units with a generating capacity of 50 MW or less not needing to install the technology basis because they already meet the new BAT limitations (which are based on the current BPT requirements for these units). The loadings also exclude the pollutant parameters biochemical oxygen demand (BOD), chemical oxygen demand (COD), total dissolved solids (TDS), and TSS to avoid double counting the loadings for other specific pollutants. The table includes the number of plants identified as discharging FGD wastewater, the total industry discharge flow rate associated with each technology option, and the total industry loading in pounds per year and TWPE per year. Table 10-10 presents the pollutant removals, in both pounds per year and TWPE per year, for the various technology options. EPA calculates the pollutant removals by subtracting the post-compliance loadings from the baseline loadings. The loadings for all units installing the technology basis, including the oil-fired units and small units (i.e., 50 MW or less generating capacity), are presented in EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* Report [U.S. EPA, 2013].

Table 10-9. Industry-Level FGD Wastewater Loadings Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Number of Plants	Total Industry Discharge Flow (MGD)	Total Industry Loading	
			Pounds/Year	TWPE/Year
Baseline	117	65.4	3,240,000,000	3,030,000
One-Stage Chemical Precipitation	117	56.8	3,650,000,000	1,490,000
One-Stage Chemical Precipitation with Biological Treatment	117	56.8	2,080,000,000	411,000
One-Stage Chemical Precipitation with Evaporation/Crystallization	117	56.8	13,500,000	36,400

Note: Excludes loadings for BOD, COD, TSS and TDS.

Note: Loadings are rounded to three significant figures.

Table 10-10. FGD Wastewater Pollutant Removals Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Total Industry Pollutant Removals	
	Pounds/Year	TWPE/Year
Reduction (Baseline –> One-Stage Chemical Precipitation)	-417,000,000[a]	1,530,000
Reduction (Baseline –> One-Stage Chemical Precipitation with Biological Treatment)	1,160,000,000	2,620,000
Reduction (Baseline –> One-Stage Chemical Precipitation with Evaporation/Crystallization)	3,220,000,000	2,990,000

Note: Excludes loadings for BOD, COD, TSS and TDS.

Note: Removals are rounded to three significant figures. The removals may not equal the subtraction of the technology option from the baseline using the values in Table 10-9 due to rounding.

a – Characterization data used to estimate pollutant concentrations for baseline FGD surface impoundments does not include concentration data for ammonia, hexavalent chromium, and TKN. These pollutants are included in the post-compliance loadings and as a result appear to increase in concentration from baseline to technology option.

EPA also estimated the industry-level post-compliance loadings for the one-stage chemical precipitation with biological treatment option for the scenario based on oil-fired units and plants with a total plant-level wet scrubbed capacity of less than 2,000 MW not installing the technology basis, which is associated with Regulatory Option 3b. Based on this scenario, there are only 17 plants would be expected to install the technology basis; therefore, EPA calculated the post-compliance loadings for each plant by applying the FGD biological treatment effluent concentrations to those 17 plants and the FGD baseline concentrations to the remaining 100 plants. Table 10-11 presents the FGD wastewater loadings at an industry level for this post-compliance scenario. The loadings presented in Table 10-11 exclude the pollutant parameters BOD, COD, TDS, and TSS to avoid double counting the loadings for other specific pollutants. The table includes the number of plants identified as discharging FGD wastewater, the total industry discharge flow rate associated with the scenario, and the total industry loading in pounds per year and TWPE per year. Table 10-12 presents the pollutant removals, in both pounds per year and TWPE per year, for the scenario. EPA calculates the pollutant removals by subtracting the post-compliance loadings from the baseline loadings.

Table 10-11. Industry-Level FGD Wastewater Loadings Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Plants with a Total Wet Scrubbed Capacity of Less Than 2,000 MW Not Installing Technology Basis

Technology Option	Number of Plants	Total Industry Discharge Flow (MGD)	Total Industry Loading	
			Pounds/Year	TWPE/Year
One-Stage Chemical Precipitation with Biological Treatment	117	59.1	2,790,000,000	2,120,000

Note: Excludes loadings for BOD, COD, TSS and TDS.

Note: Loadings are rounded to three significant figures.

Table 10-12. FGD Wastewater Pollutant Removals Based on Oil-Fired Units and Plants with a Total Wet Scrubbed Capacity of Less Than 2,000 MW Not Installing Technology Basis

Technology Option	Total Industry Pollutant Removals	
	Pounds/Year	TWPE/Year
Reduction (Baseline –> One-Stage Chemical Precipitation with Biological Treatment)	446,000,000	908,000

Note: Excludes loadings for BOD, COD, TSS and TDS.

Note: Removals are rounded to three significant figures. The removals may not equal the subtraction of the technology option from the baseline using the values in Table 10-9 and Table 10-11 due to rounding.

10.4.2 Ash Transport Water Loadings and TWPE

EPA calculated plant-specific loadings for the baseline discharges and technology option considered for ash transport water. For baseline loadings, EPA multiplied the plant-specific ash transport water discharge flow rate for each type of ash transport water (i.e., fly ash, bottom ash, or combined ash transport water) by the appropriate average concentration data set for the type of discharge. For example, for each fly ash impoundment, EPA multiplied the normalized discharge flow rate described in Section 10.3.2 for the plant's fly ash impoundment by the average concentration data set associated with fly ash impoundments presented in Section 10.2.2. EPA identified two plants transferring bottom ash transport water to a POTW. For these two plants, EPA adjusted the baseline loadings to account for pollutant removals associated with POTW treatment, as described in Section 10.1.

As described in Section 10.2.2, EPA collected ash transport water characterization data for fly ash impoundments, bottom ash impoundments, and combined ash impoundments. As such, EPA calculated loadings for each of these different types of ponds at a plant-level. Because EPA considered regulatory options that would establish different effluent requirements for fly ash and bottom ash, EPA analyzed the pollutant loadings and removals for these two wastestreams separately; therefore, EPA separated the loadings for combined ash impoundments into fly ash loadings and bottom ash loadings. To do this, EPA used data from the EPRI PISCES reports to estimate the breakout of the loadings among fly ash and bottom ash contributions. The PISCES reports include information from several plants operating impoundments receiving either fly ash or bottom ash transport water. The reports include a table presenting loadings associated with each stream entering the impoundment for several metal pollutants. EPA used the fly ash and bottom ash loadings presented in the reports to calculate a site-specific percent loading for fly ash and bottom ash for each pollutant. EPA then calculated an average percent loading for fly ash and bottom ash using data from all available pollutants. EPA determined that, on average, pollutant contributions from fly ash account for 86 percent of combined ash loadings, with bottom ash contributing only 14 percent. Therefore, EPA assumed fly ash and bottom ash account for 86 and 14 percent, respectively, of all combined ash loadings for those pollutants for which a specific value could not be calculated using the EPRI data, EPA then used these percentages to break out the combined ash loadings into associated fly ash and bottom ash loadings. After separating the loadings into fly ash and bottom ash components, EPA calculated total fly ash and bottom ash transport water baseline loadings for each plant.

For both fly ash and bottom ash transport water, EPA is considering only one technology option: conversion to dry or closed-loop recycle ash handling. EPA assumes that all plants currently discharging ash transport water will install dry handling systems for fly ash and will operate wet-sluicing bottom ash handling systems as a closed loop system (i.e., zero discharge) or will convert to dry bottom ash handling, resulting in post-compliance loadings of zero for fly ash and bottom ash transport water pollutants for those plants subject to the proposed requirements.

Table 10-13 presents the results of the baseline and post-compliance ash impoundment loadings on an industry level. The table includes the number of impoundments discharging each type of ash transport water, the total industry discharge flow rate, and the total industry loadings in pounds per year and TWPE per year associated with each type of impoundment. The industry loadings presented in Table 10-13 exclude the pollutant parameters BOD, COD, TDS, and TSS to avoid double counting the loadings for other specific pollutants. Table 10-14 presents the pollutant removals, in both pounds per year and TWPE per year, between the baseline and the dry or closed-loop recycle handling technology option. The pollutant removals are based on the oil-fired units and those units with a generating capacity of 50 MW or less not needing to install the technology basis because they already meet the new BAT limitations (which are based on the current BPT requirements for these units). EPA calculates the pollutant removals by subtracting the post-compliance loadings from the baseline loadings. The pollutant removals for all units installing the technology basis, including the oil-fired units and small units (i.e., 50 MW or less generating capacity), are presented in EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* Report [U.S. EPA, 2013].

Table 10-13. Industry-Level Ash Impoundment Loadings by Type of Impoundment Excluding BOD, COD, TDS, and TSS

Type of Ash Impoundment	Number of Impoundments	Total Baseline Industry Discharge Flow (MGD)	Total Industry Baseline Loading		Total Industry Post-Compliance Loading	
			Pounds/Year	TWPE/Year	Pounds/Year	TWPE/Year
Fly Ash						
Fly Ash Pond	16	61.7	237,000,000	688,000	3,800,000	11,000
Combined Ash Pond[b]	80	262[a]	241,000,000	1,830,000	2,950,000	22,500
Bottom Ash						
Bottom Ash Pond	174	327	1,660,000,000	2,420,000	5,100,000	7,290
Combined Ash Pond[b]	80	262[a]	44,900,000	295,000	550,000	3,610
TOTAL	**272**	**651**	**2,180,000,000**	**5,240,000**	**12,400,000**	**44,400**

Note: Excludes loadings for BOD, COD, TSS, and TDS.

Note: Loadings are rounded to three significant figures.

a – The total discharge flow from all combined impoundments is 262 MGD. The fly ash contribution and bottom ash contribution cannot be determined with the data provided in the Steam Electric Survey.

b – The combined ash pond loadings were calculated based on the data used in the loadings calculation, but then the total combined ash pond loadings were split between fly ash and bottom ash based the EPRI data, described in this section.

Table 10-14. Fly Ash and Bottom Ash Pollutant Removals Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Type of Ash Impoundment	Technology Option	Total Industry Pollutant Removals	
		Pounds/Year	TWPE/Year
Fly Ash	Reduction (Baseline –> Technology Option)	471,000,000	2,490,000
Bottom Ash	Reduction (Baseline –> Technology Option)	1,700,000,000	2,710,000

Note: Excludes loadings for BOD, COD, TSS, and TDS.

Note: Removals are rounded to three significant figures. The removals may not equal the subtraction of the technology option from the baseline using the values in Table 10-13 due to rounding.

EPA also estimated the industry-level pollutant loadings for plants to convert only the generating units that are greater than 400 MW to dry or closed-loop recycle bottom ash handling systems. However, EPA used a different approach to estimate the plant-level loadings for this analysis. For those plants with all generating units with a nameplate capacity of 400 MW or less, EPA assumed that the post-compliance loadings would be equal to the baseline loadings and for those plants with all generating units with a nameplate capacity greater than 400 MW, EPA assumed that the post-compliance loadings would be zero (as was done for Options 4 and 5). For those plants that have at least one generating unit with a nameplate capacity of 400 MW or less and at least one other generating unit with a nameplate capacity of greater than 400 MW, EPA approximated the plant-level bottom ash pollutant removals. To perform this approximation, EPA calculated a plant-level bottom ash adjustment factor based on the amount of bottom ash generated by the generating units expected to incur compliance costs with a nameplate capacity greater than 400 MW compared to the total amount of bottom ash generated at the plant for those generating units expected to incur compliance costs (excluding the generating units with a nameplate capacity of 50 MW or less). This is the same adjustment factor that was calculated for the bottom ash compliance costs for Option 4a, described in Section 9.7.3. EPA then multiplied the bottom ash adjustment factors by the plant-level bottom ash pollutant removals calculated based on all generating units (other than oil-fired units) with a nameplate capacity greater than 50 MW to estimate the bottom ash pollutant removals for this analysis. For more details on how EPA estimated these plant-level bottom ash pollutant removals, see the memorandum entitled “Memorandum to the Rulemaking Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a” (DCN SE03834).

Table 10-15 presents the pollutant removals, in both pounds per year and TWPE per year, between the baseline and the dry or closed-loop recycle handling technology option associated with Regulatory Option 4a. The pollutant removals are based on the oil-fired units and those units with a generating capacity of 400 MW or less not needing to install the technology basis because they already meet the new BAT limitations (which are based on the current BPT requirements for these units). EPA calculates the pollutant removals by subtracting the post-compliance loadings from the baseline loadings.

Table 10-15. Bottom Ash Pollutant Removals Based on Oil-Fired Units and Units 400 MW or Less Not Installing Technology Basis

Type of Ash Impoundment	Technology Option	Total Industry Pollutant Removals	
		Pounds/Year	TWPE/Year
Bottom Ash	Reduction (Baseline –> Technology Option)	991,000,000	1,570,000

Note: Excludes loadings for BOD, COD, TSS, and TDS.

Note: Removals are rounded to three significant figures.

10.4.3 Combustion Residual Landfill Leachate Loadings and TWPE

EPA calculated plant-specific loadings for each of the technology options considered for combustion residual landfill leachate. For baseline loadings, EPA multiplied the plant-specific leachate discharge flow rate with the average pollutant concentrations that represent untreated combustion residual landfill leachate. EPA identified seven plants transferring landfill leachate to a POTW. For these seven plants, EPA adjusted the baseline loadings to account for pollutant removals associated with POTW treatment.

For the one-stage chemical precipitation technology option, EPA assumed that all plants would install that type of treatment system. No plants currently treat leachate with a one-stage chemical precipitation system so all plants would need to install treatment to meet the effluent requirements associated with this option. EPA calculated discharge loadings for these plants using the average concentration data set associated with one-stage chemical precipitation systems, presented in Section 10.2.3, and plant-specific leachate flow rates.

For the one-stage chemical precipitation treatment system with biological treatment technology option, EPA assumed that all plants would install that type of treatment to meet the effluent requirements associated with this technology option. EPA calculated the discharge loadings for these plants using the average concentration data set associated with one-stage chemical precipitation systems followed by biological treatment, presented in Section 10.2.3, and plant-specific leachate flow rates.

Table 10-16 presents the combustion residual landfill leachate loadings at an industry level for baseline and each post-compliance technology basis. The loadings presented in Table 10-16 are based on the oil-fired units and those units with a generating capacity of 50 MW or less not needing to install the technology basis because they already meet the new BAT limitations (which are based on the current BPT requirements for these units). The loadings also exclude the pollutant parameters BOD, COD, TDS, and TSS to avoid double counting the loadings for other specific pollutants. Included in the table is the number of plants discharging combustion residual landfill leachate, the total industry flow rate associated with each technology option, and the total industry loading in pounds per year and TWPE per year. Table 10-17 presents the pollutant removals, in both pounds per year and TWPE per year, for the various technology options. EPA calculated the pollutant removals by subtracting the post-compliance loadings from the baseline loadings. The loadings for all units installing the technology basis, including the oil-fired units and small units (i.e., 50 MW or less generating capacity), are presented in EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* Report [U.S. EPA, 2013].

Table 10-16. Industry-Level Combustion Residual Landfill Leachate Loadings Excluding BOD, COD, TDS, and TSS and Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Number of Plants	Total Industry Discharge Flow (MGD)	Total Industry Loading	
			Pounds/Year	TWPE/Year
Baseline	102	7.90	89,800,000	56,500
One-Stage Chemical Precipitation	102	7.90	80,900,000	20,900
One-Stage Chemical Precipitation with biological treatment	102	7.90	61,800,000	13,600

Note: Excludes loadings for BOD, COD, TSS and TDS.

Note: Loadings are rounded to three significant figures.

Table 10-17. Combustion Residual Landfill Leachate Pollutant Removals Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Technology Option	Total Industry Pollutant Removals	
	Pounds/Year	TWPE/Year
Reduction (Baseline –> One-Stage Chemical Precipitation)	8,900,000	35,600
Reduction (Baseline –> One-Stage Chemical Precipitation with Biological Treatment)	28,000,000	42,900

Note: Excludes loadings for BOD, COD, TSS and TDS.

Note: Removals are rounded to three significant figures. The removals may not equal the subtraction of the technology option from the baseline using the values in Table 10-16 due to rounding.

10.4.4 Pollutant Loadings and Removals for Regulatory Options

As described in Section 8, EPA evaluated eight regulatory options comprised of various combinations of the technology options considered for each wastestream. EPA estimated the pollutant removals associated with steam electric power plants to achieve compliance for each regulatory option under consideration. Table 10-18 presents the total industry loadings and pollutant removals at baseline and for each of the eight regulatory options. The loadings and TWPE values presented in these tables exclude pollutant parameters BOD, COD, TDS, and TSS. The table presents the estimated loadings and pollutant removals based on the oil-fired units and units with a capacity of 50 MW or less not needing to install the appropriate technology bases.[98] The loadings and pollutant removals for all units installing the technology basis, including the oil-fired units and small units (i.e., 50 MW or less generating capacity), are presented in EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category* Report [U.S. EPA, 2013]. The pollutant-level baseline loadings and pollutant-level removals for each regulatory option by wastestream are presented in the memorandum entitled, "Steam Electric Pollutant-Level Loadings and Removals for Each Wastestream and Regulatory Option" (DCN SE03970).

Table 10-18. Estimated Pollutant Removals by Regulatory Option Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Regulatory Option	Total Industry Loading		Total Industry Pollutant Removals [a]	
	Pounds/Year	TWPE/Year	Pounds/Year	TWPE/Year
Baseline	5,500,000,000	8,320,000	0	0
1	5,920,000,000	6,790,000	-417,000,000[b]	1,530,000
3a	5,030,000,000	5,830,000	471,000,000	2,490,000
2	4,350,000,000	5,710,000	1,160,000,000	2,620,000
3b	4,590,000,000	4,920,000	916,000,000	3,400,000

[98] Except for Regulatory Options 4a and 3b. For Regulatory Option 4a, the bottom ash estimated loadings and pollutant removals are based on the oil-fired units and units with a capacity of 400 MW or less not needing to install the appropriate technology bases. For Regulatory Option 3b, the FGD wastewater estimated loadings and pollutant removals are based on the oil-fired units and plants with a total wet scrubbed capacity of less than 2,000 MW not needing to install the appropriate technology bases.

Table 10-18. Estimated Pollutant Removals by Regulatory Option Based on Oil-Fired Units and Units 50 MW or Less Not Installing Technology Basis

Regulatory Option	Total Industry Loading		Total Industry Pollutant Removals [a]	
	Pounds/Year	TWPE/Year	Pounds/Year	TWPE/Year
3	3,880,000,000	3,220,000	1,630,000,000	5,100,000
4a	2,870,000,000	1,640,000	2,620,000,000	6,680,000
4	2,160,000,000	474,000	3,340,000,000	7,850,000
5	107,000,000	102,000	5,400,000,000	8,220,000

Note: Excludes loadings for BOD, COD, TDS, and TSS.

Note: Removals are rounded to three significant figures. The removals may not equal the sum of the removals presented in the tables in this section from the various wastestreams due to rounding.

a - Compared to baseline.

b - Characterization data used to estimate pollutant concentrations for baseline FGD surface impoundments does not include concentration data for ammonia, hexavalent chromium, and TKN. These pollutants are included in the post-compliance loadings and as a result appear to increase in concentration from baseline to technology option.

10.5 References

1. Duke Energy. 2011a. Industry Provided Sampling Data from Duke Energy's Belews Creek Steam Station. (17 August). DCN SE01808.
2. Duke Energy. 2011b. Industry Provided Sampling Data from Duke Energy's Allen Steam Station. (17 August). DCN SE01809.
3. Eastern Research Group (ERG). 2005. Memorandum to 2006 Effluent Guidelines Program Plan Docket, From Ellie Codding and Deb Bartram, ERG, re: Publicly Owned Treatment Works (POTW) Percent Removals Used for the TRI Releases2002 Database. (12 August). DCN SE02932.
4. Eastern Research Group (ERG). 2006. Toxic Weighting Factor Development in Support of CWA 304(m) Planning Process. (June). DCN SE02931.
5. Eastern Research Group, Inc. (ERG). 2008. Final Sampling Episode Report, Buckeye Power Company's Cardinal Power Plant. (26 August). DCN SE02107.
6. Eastern Research Group (ERG). 2012a. Final Sampling Episode Report, Duke Energy Carolinas' Belews Creek Steam Station. (13 March). DCN SE01305.
7. Eastern Research Group (ERG). 2012b. Final Sampling Episode Report, We Energies' Pleasant Prairie Power Plant. (13 March). DCN SE01306.
8. Eastern Research Group (ERG). 2012c. Final Sampling Episode Report, Duke Energy Miami Fort Station. (13 March). DCN SE01304.
9. Eastern Research Group (ERG). 2012d. Final Sampling Episode Report, Duke Energy Carolinas' Allen Steam Station. (13 March). DCN SE01307.
10. Eastern Research Group (ERG). 2012e. Final Sampling Episode Report, Mirant Mid-Atlantic, LLC's Dickerson Generating Station. (13 March). DCN SE01308.

11. Eastern Research Group (ERG). 2012f. Final Sampling Episode Report, Allegheny Energy's Hatfield's Ferry Power Station. (13 March). DCN SE01310.
12. Eastern Research Group (ERG). 2012g. Final Sampling Episode Report, RRI Energy's Keystone Generating Station. (13 March). DCN SE01309.
13. Eastern Research Group (ERG). 2012h. Final Sampling Episode Report and Site Visit Notes, Enel's Federico II Power Plant (Brindisi). (8 August). DCN SE02013.
14. Eastern Research Group (ERG). 2012i. Final Power Plant Monitoring Data Collected Under Clean Water Act Section 308 Authority ("CWA 308 Monitoring Data"). (30 May). DCN SE01326.
15. Eastern Research Group (ERG). 2013. Steam Electric Technical Questionnaire Database ("Steam Electric Survey"). (19 April). DCN SE01958.
16. Electric Power Research Institute (EPRI). 1997 - 2001. PISCES Water Characterization Field Study, Sites A-G. Palo Alto, CA. DCN SE01818 through SE01823.
17. NCDENR. 2011. North Carolina Department of Environment and Natural Resources (NCDENR). State Provided Sampling Data from North Carolina's Progress Energy Roxboro Plant. (26 June). DCN SE01812.
18. Utility Water Act Group (UWAG). 2008. Form 2C Effluent Guidelines Database. (30 June). DCNs SE02918 and SE02918A1.
19. U.S. EPA. 1982. *Development Document for Effluent Limitations Guidelines and Standards and Pretreatment Standards for the Steam Electric Point Source Category*. EPA-440-1-82-029. Washington, DC. (November). DCN SE02933.
20. U.S. EPA. 2013. Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category Report. (19 April). DCN SE01957.

SECTION 11
POLLUTANTS SELECTED FOR REGULATION

This section describes the selection of regulated pollutants for each wastestream for which EPA evaluated new or revised discharge requirements in the Steam Electric ELGs. Regulated pollutants are pollutants for which EPA proposes to establish numerical effluent limitations and standards. This section describes the methodology and rationale EPA used to select the subset of regulated pollutant parameters from the list of pollutants of concern (POC) for each wastestream.

11.1 SELECTION OF REGULATED POLLUTANT FOR DIRECT DISCHARGERS

The list of POCs for each wastestream represents those pollutants that are present at treatable concentrations in a significant percentage of untreated wastewater samples from that wastestream; the selection of POCs for each wastestream is presented in Section 6.7 of this document. Effluent monitoring for all POCs is not necessary to ensure that steam electric wastewater pollution is adequately controlled because many of the pollutants originate from similar sources, have similar treatabilities, are removed by similar mechanisms, and are treated to similar concentrations. Therefore, it may be sufficient to monitor for one pollutant as a surrogate or indicator of several others.

From the POC list for each wastestream, EPA selected a subset of pollutants for establishing numerical effluent limitations. EPA considered the following factors in selecting regulated pollutants from the list of POCs for each subcategory:

- The pollutant was detected in the untreated wastewater at the BAT plant(s) at treatable levels in a significant number of samples. This was the same methodology used to identify the POCs, as described in Section 6.7.
- The pollutant is not used as a treatment chemical in the treatment technology that serves as a basis for the proposed regulatory option. EPA excluded pollutants that may serve as treatment system additives: aluminum, calcium, iron, sodium, and phosphorus. EPA eliminated these pollutants because regulating these pollutants could interfere with efforts to optimize treatment system operation.
- The pollutant is effectively treated by the treatment technology that serves as the basis for the proposed regulatory option. EPA excluded pollutants for which the treatment technology was ineffective (i.e., pollutant concentrations remained approximately unchanged or increased across the treatment system).
- The pollutant is not adequately controlled through the regulation of another pollutant.
- The following subsections describe EPA's pollutant selection analysis for each wastestream.

11.1.1 <u>FGD Wastewater</u>

EPA proposes establishing BAT and NSPS limitations and standards for FGD wastewater for four pollutants: arsenic, mercury, nitrate/nitrite, and selenium. These limitations and standards are based on a one-stage chemical precipitation system followed by anoxic/anaerobic biological treatment, as described in Section 13.8. The regulated pollutant selection criteria matrix for the 35 POCs considered for regulation for FGD wastewater is illustrated in Table 11-1. The following discussion explains the rationale used to select which of the 35 POCs to regulate at BAT/NSPS for the preferred options.

- Conventional Pollutants: EPA identified oil and grease (O&G) and total suspended solids (TSS) as POCs. TSS and O&G are adequately controlled by existing BPT limitations.
- Treatment Chemicals: EPA identified and eliminated five POCs that are also used as treatment chemicals: aluminum, calcium, iron, sodium, and phosphorus.
- Pollutants Not Effectively Treated by the Proposed BAT/NSPS Technology: EPA eliminated eight pollutants, ammonia, boron, chloride, COD, cyanide, sulfate, TDS, and TKN, because the technology option associated with the preferred options is not designed to achieve consistent effluent concentrations of these pollutants.
- Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants: The remaining pollutants are metals and nitrate/nitrite. As described in Section 7, chemical precipitation systems use chemicals to alter the physical state of dissolved and suspended solids to help settle and remove solids from the wastewater. The metals present in the wastewater form insoluble hydroxides and/or sulfide complexes. The solubilities of these complexes vary by pH, therefore, specific pHs can be targeted to remove specific metals. But in this process, most metals are precipitated to at least some degree, thereby resulting in the removal of a wide range of metals. EPA's design basis for the BAT system uses both hydroxide and sulfide precipitation, as well as iron coprecipitation. EPA selected arsenic and mercury as regulated pollutants and as indicators of effective removals of many other metal pollutants of concern present in FGD wastewater, such as cadmium and chromium. While most metals can be removed to low levels using chemical precipitation alone, selenium requires additional treatment to achieve consistent removals. Therefore, EPA also selected selenium and nitrate/nitrite for regulation.

Table 11-1. Pollutants Considered for Regulation for Direct Dischargers (BAT/NSPS): FGD Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the Proposed BAT/NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Conventional	Oil and Grease			✓
	Total Suspended Solids			✓
Priority Pollutants	Antimony			✓
	Arsenic			✓
	Beryllium			✓
	Cadmium			✓
	Chromium			✓
	Copper			✓
	Cyanide		✓	
	Lead			✓
	Mercury			✓
	Nickel			✓
	Selenium			✓
	Thallium			✓
	Zinc			✓
Nonconventional	Aluminum	✓		
	Ammonia		✓	
	Barium			✓
	Boron		✓	
	Calcium	✓		
	Chemical Oxygen Demand		✓	
	Chloride		✓	
	Cobalt			✓
	Iron	✓		
	Magnesium			✓

Table 11-1. Pollutants Considered for Regulation for Direct Dischargers (BAT/NSPS): FGD Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the Proposed BAT/NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Nonconventional	Manganese			✓
	Molybdenum			✓
	Nitrate/Nitrite			✓
	Nitrogen, Kjeldahl		✓	
	Phosphorus	✓		
	Sodium	✓		
	Sulfate		✓	
	Titanium			✓
	Total Dissolved Solids		✓	
	Vanadium			✓

11.1.2 <u>Fly Ash Transport Water</u>

EPA proposes establishing BAT limitations requiring no discharge of wastewater pollutants from fly ash transport water for each of the preferred regulatory options (i.e., Option 3a, 3b, 3, and 4a). Additionally, the same standard was already set for NSPS as part of the 1982 revisions to the ELGs. Therefore, the Agency did not apply its pollutant selection methodology to this wastestream. All pollutants of concern would be regulated and removed by the preferred options.

11.1.3 <u>Bottom Ash Transport Water</u>

EPA proposes establishing BAT limitations equal to the current BPT limitations for bottom ash transport water under Regulatory Options 3a, 3b, and 3. Under Regulatory Option 4a, EPA proposes establishing BAT limitations requiring no discharge of wastewater pollutants from bottom ash transport water for generating units with a nameplate capacity greater than 400 MW, while EPA is proposing to establish BAT limitations equal to the current BPT limitations for bottom ash transport water for all generating units with a nameplate capacity of 400 MW or less. EPA also proposes establishing NSPS standards requiring no discharge of wastewater pollutants from bottom ash transport water. Therefore, because either all pollutants are regulated (Regulatory Option 4a for generating units with a nameplate capacity of greater than 400 MW) or the pollutants selected are the same as those regulated under BPT (Regulatory Options 3a, 3b, 3, and 4a for generating units with a nameplate capacity of 400 MW or less), the Agency did not apply its pollutant selection methodology to this wastestream.

11.1.4 <u>Combustion Residual Leachate</u>

EPA proposes establishing BAT limitations for combustion residual leachate equal to the current BPT limitations for low volume waste sources under a preferred regulatory options. EPA is proposing to establish NSPS limitations for arsenic and mercury. These NSPS limitations are based on a one-stage chemical precipitation system. The regulated pollutant selection criteria matrix for the 16 POCs considered for regulation for combustion residual leachate is illustrated in Table 11-2. The following discussion explains the rationale used to select which of the 16 POCs to regulate at NSPS (based on Regulatory Option 4).[99]

- Conventional Pollutants: EPA identified O&G and TSS as POCs. TSS and O&G are adequately controlled by existing BPT limitations.
- Treatment Chemicals: EPA identified and eliminated four POCs that are also used as treatment chemicals: aluminum, calcium, iron, and sodium.
- Pollutants Not Effectively Treated by the Proposed NSPS Technology: EPA eliminated five pollutants, boron, chloride, selenium, sulfate, and total dissolved solids, because the technology option associated with Regulatory Option 4 is not designed to achieve consistent effluent concentrations of these pollutants.
- Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants: The remaining pollutants of concern are all metals. As explained above for FGD

[99] These are also the 16 POCs that would be considered for regulation under BAT Options 4 and 5.

wastewater, chemical precipitation is effective at removing metals present in wastewater, especially when both hydroxide and sulfide precipitation mechanisms are employed, which is part of the basis for the technology option. EPA selected arsenic and mercury as regulated pollutants and as indicators of effective removals of many other metal pollutants of concern present in combustion residual leachate, such as magnesium and manganese.

11.1.5 Gasification Wastewater

For gasification wastewater, EPA is proposing to establish BAT and NSPS limitations and standards for four pollutants: arsenic, mercury, selenium, and TDS. These limitations and standards are based on a vapor-compression evaporation system for direct dischargers. The regulated pollutant selection criteria matrix for the 20 POCs considered for regulation for gasification wastewater is illustrated in Table 11-3. The following discussion explains the rationale used to select which of the 20 POCs to regulate at BAT/NSPS.

- Conventional Pollutants: EPA identified BOD_5 as a POC. BOD is not subject to BAT limitations.
- Pollutants Not Effectively Treated by the Proposed BAT/NSPS Technology: EPA eliminated five pollutants, ammonia, COD, cyanide, nitrate/nitrite, and TKN, because the technology option associated with the preferred options is not designed to achieve consistent effluent concentrations of these pollutants.
- Pollutants Directly Regulated or Controlled by Regulation of Other Pollutants: The remaining pollutants are metals and salt ions (i.e., chloride and sulfate). As described in Section 7, the vapor-compression evaporation system uses steam to evaporate the water from the wastewater, producing a distillate stream and a solid residual byproduct (i.e., crystallized salts). The removal of metals from this system will depend on the volatility of the metals because the more volatile the metal, the greater amount that will be carried over into the distillate stream. Therefore, EPA selected three metals, arsenic, mercury, and selenium to represent different volatilities of metals and act as indicator pollutants for other metals. EPA also selected TDS for regulation as an indicator of pollutants (e.g., sodium, chloride) present in the wastewater.

11.1.6 Flue Gas Mercury Control Wastewater

EPA proposes establishing BAT limitations requiring no discharge of wastewater pollutants from FGMC wastewater. EPA also proposes establishing NSPS standards requiring no discharge of wastewater pollutants from FGMC wastewater for NSPS. Therefore, the Agency did not apply its pollutant selection methodology to this wastestream. All pollutants of concern would be regulated and removed by the preferred options.

11.1.7 Nonchemical Metal Cleaning Wastes

EPA proposes establishing BAT limitations for nonchemical metal cleaning wastes for two pollutants, copper and iron. EPA is also proposing to establish NSPS limitations for nonchemical metal cleaning wastes for TSS, O&G, copper, and iron. These limitations and standards are based on the current BPT limitations for metal cleaning wastes. Because the limitations and standards are based on the existing BPT limitations, the pollutants for regulation are already identified, and therefore, EPA did not apply its pollutant selection methodology to this wastestream.

Table 11-2. Pollutants Considered for Regulation for Direct Dischargers (BAT/NSPS): Combustion Residual Leachate

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the Proposed BAT/NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Conventional Pollutants	Oil and Grease			✓
	Total Suspended Solids			✓
Priority Pollutants	Arsenic			✓
	Mercury			✓
	Selenium		✓	
Nonconventional Pollutants	Aluminum	✓		
	Boron		✓	
	Calcium	✓		
	Chloride		✓	
	Iron	✓		
	Magnesium			✓
	Manganese			✓
	Molybdenum			✓
	Sodium	✓		
	Sulfate		✓	
	Total Dissolved Solids		✓	

Table 11-3. Pollutants Considered for Regulation for Direct Dischargers (BAT/NSPS): Gasification Wastewater

Pollutant Group	Pollutant of Concern	Treatment Chemical	Not Effectively Treated by the Proposed BAT/NSPS Technology	Directly Regulated or Controlled by Regulation of Another Parameter
Priority Pollutants	Antimony			✓
	Arsenic			✓
	Cyanide		✓	
	Mercury			✓
	Nickel			✓
	Selenium			✓
	Thallium			✓
Conventional Pollutants	Biochemical Oxygen Demand			✓
Nonconventional Pollutants	Aluminum			✓
	Ammonia		✓	
	Boron			✓
	Chemical Oxygen Demand		✓	
	Chloride			✓
	Iron			✓
	Manganese			✓
	Nitrate/Nitrite		✓	
	Nitrogen, Kjeldahl		✓	
	Sodium			✓
	Sulfate			✓
	Total Dissolved Solids			✓

11.2 REGULATED POLLUTANT SELECTION METHODOLOGY FOR INDIRECT DISCHARGERS

Unlike direct dischargers whose wastewater will receive no further treatment once it leaves the plant, indirect dischargers send their wastewater to publicly-owned treatment works (POTWs) for further treatment. However, POTWs typically install secondary biological treatment systems that are designed to control conventional pollutants (i.e., BOD, TSS, oil & grease (O&G), pH, and fecal coliform), the principal parameters in domestic sewage. Except for nutrient control for nitrogen compounds and phosphorus, POTWs usually do not install advanced or tertiary treatment technology to control priority and nonconventional pollutants, although secondary biological treatment systems may achieve significant removals for some priority pollutants. Instead, the Clean Water Act envisions that implementation of pretreatment programs and industrial compliance with categorical pretreatment standards will adequately control toxic and nonconventional pollutants in municipal effluents.

Section 307(b) and (c) of the CWA requires EPA to promulgate pretreatment standards for pollutants that are not susceptible to treatment by POTWs or which would interfere with the operation of POTWs. EPA looks at a number of factors in selecting the technology basis for pretreatment standards for existing and new sources. These factors are generally the same as those considered in establishing BAT and NSPS, respectively. However, unlike direct dischargers whose wastewater will receive no further treatment once it leaves the plant, indirect dischargers send their wastewater to POTWs for further treatment. As such, EPA must also determine that a pollutant is not susceptible to treatment at a POTW or would interfere with POTW operations.

Therefore, for indirect dischargers, before establishing PSES/PSNS for a pollutant, EPA examines whether the pollutant “passes through” a POTW to waters of the U.S. or interferes with the POTW operation or sludge disposal practices. In determining whether a pollutant would pass though POTWs for PSES/PSNS, EPA generally compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment to the percentage removed by BAT/NSPS treatment systems. A pollutant is determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by direct dischargers complying with BAT/NSPS effluent limitations and standards. Pretreatment standards are established for those pollutants regulated under BAT/NSPS that pass through POTWs to waters of the U.S. or interfere with POTW operations or sludge disposal practices. This approach to the definition of pass-through satisfies two competing objectives set by Congress: (1) that standards for indirect dischargers be equivalent to standards for direct dischargers, and (2) that the treatment capability and performance of POTWs be recognized and taken into account in regulating the discharge of pollutants from indirect dischargers.

The POTW pass-through analysis was performed for pollutants selected for regulation for direct dischargers for each wastestream of concern. Those pollutants that EPA determines pass through POTWs are the pollutants EPA proposes to regulate. The following pollutants were not analyzed for pass through even if selected for regulation under BAT/NSPS: biochemical oxygen demand (BOD_5), TSS, and O&G. POTWs are designed to treat these pollutants; therefore, they were not considered to pass through.

For the proposed Steam Electric ELGs, EPA is setting limitations for the following wastestreams:

- FGD wastewater;
- Fly ash transport water;
- Bottom ash transport water;
- Combustion residual leachate;
- Gasification wastewater;
- Flue gas mercury control wastewater; and
- Nonchemical metal cleaning wastes.

EPA conducted the pass-through analysis for all regulated pollutants for FGD wastewater, combustion residual leachate, and gasification wastewater. EPA did not conduct its traditional POTW pass-through analysis for fly ash transport water, bottom ash transport water, and flue gas mercury control wastewater because limitations for these wastestreams for direct dischargers consist of no discharge of process wastewater pollutants to waters of the U.S.[100] Because the BAT/NSPS technology options for fly ash transport water, bottom ash transport water, and flue gas mercury control wastewater achieve 100 percent removal of all pollutants, which is greater than the percent removals by POTWs, EPA determined the pollutants would pass through the POTW for these wastestreams.

During the 1976 development of pretreatment standards for chemical metal cleaning wastes, EPA selected pollutants for regulation based on two criteria:

- The pollutant has the potential to harm the POTW (e.g., impair the activity of the biological treatment system); or
- The pollutant has the potential to harm the receiving water (i.e., if the pollutant is not removed or is removed inadequately by the POTW).

Using these criteria, the Agency determined it was appropriate to establish pretreatment standards for the discharge of copper in chemical metal cleaning wastes. EPA believes that, as is the case for copper in chemical metal cleaning wastes, the copper present in nonchemical metal cleaning wastes would pass through the POTW.

The following subsections present the POTW pass-through analysis:

- Methodology for determining BAT percent removals;
- Methodology for determining POTW percent removals; and
- Results of the POTW pass-through analysis.

[100] To ensure standards for indirect dischargers be equivalent to limitations for direct dischargers, EPA similarly designates standards for these wastestreams as zero discharge.

11.2.1 Methodology for Determining BAT Percent Removals

EPA calculated percent removals for each selected technology option using the data used to determine the long-term averages (LTAs) and limitations/standards for the selected BAT or NSPS technology option. Therefore, the data used to calculate the treatment option percent removals was subjected to the same date editing criteria as the data used to establish the limitations/standards. See Section 13.

1. For each pollutant and each model plant for which EPA had influent and effluent data, EPA averaged the influent data and effluent data to obtain a plant-specific average influent and effluent concentration, respectively.
2. EPA calculated percent removals for each pollutant for each model plant from the site-specific average influent and effluent concentrations using the following equation:

$$\text{PercentRemoval} = \frac{\text{AverageInfluentConcentration - AverageEffluentConcentration}}{\text{AverageInfluentConcentration}} \text{ x } 100$$

3. If EPA calculated percent removals for multiple model plants for a pollutant, EPA used the median percent removal for that pollutant from the plant-specific percent removals as the BAT option percent removal.

11.2.2 Methodology for Determining POTW Percent Removals

EPA generally calculated pollutant percent removals at POTWs nationwide from two available data sources:

- Fate of Priority Pollutants in Publicly Owned Treatment Works, September 1982, EPA 440/1-82/303 (50 POTW Study); and
- National Risk Management Research Laboratory (NRMRL) Treatability Database, Version 5.0, February 2004 (formerly called the Risk Reduction Engineering Laboratory (RREL) database).

When available for a pollutant, EPA used data from the 50-POTW Study. For those pollutants not covered in the 50 POTW Study, EPA used NRMRL data. The 50 POTW Study presents data on the performance of 50 well-operated POTWs that employ secondary treatment to remove toxic pollutants. EPA edited the data to minimize the possibility that low POTW removals might simply reflect low influent concentrations instead of treatment effectiveness. The criteria used in editing the 50-POTW study data for this rule are listed below:

1. Substitute the standardized pollutant-specific analytical ML for values reported as “not detected,” “trace,” “less than (followed by a number),” or a number less than the standardized minimum analytical detection limit (ML); and

2. Retain pollutant influent and corresponding effluent values if the average pollutant influent level is greater than or equal to 10 times the pollutant ML.

For each POTW that had data pairs that passed the editing criteria, EPA calculated its percent removal for each pollutant using the equation provided above. EPA then used the median value of all the POTW pollutant-specific percent removals as the nationwide percent removal in its pass-through analysis. For this pass-through analysis, EPA used the 50-POTW study data for arsenic and mercury.

The NRMRL database, used to augment the POTW database for the pollutants that the 50 POTW Study did not cover, is a computerized database that provides information, by pollutant, on removals obtained by various treatment technologies. The database provides the user with the specific data source and the industry from which the wastewater was generated. For each of the pollutants regulated at BAT that were not found in the 50-POTW database (e.g., selenium), EPA used data from portions of the NRMRL database. EPA applied the following editing criteria:

1. Only treatment technologies representative of typical POTW secondary treatment operations (activated sludge, activated sludge with filtration, aerated lagoons) were used;
2. Only information pertaining to domestic or industrial wastewater were used;
3. Pilot-scale and full-scale data were used, while bench-scale data were eliminated; and
4. Only data from peer-reviewed journals or government reports were used.

Using the NRMRL pollutant removal data that passed the above criteria, EPA calculated the average percent removal for each pollutant. For this pass-through analysis, EPA used the NRMRL database for selenium.

Neither source includes pollutant removal data for TDS. Secondary treatment technologies are generally understood to be ineffective at removing TDS and as such TDS removals at POTWs are likely to be close to zero. For purposes of this pass through analysis, EPA assumes the percent removal to be zero [Metcalf & Eddy, 2003].

11.2.3 Results of POTW Pass-Through Analysis

The following subsections provide the results of EPA's pass through analyses for FGD wastewater, combustion residual leachate, and gasification wastewater using the methodology described above. EPA did not conduct its traditional pass-through analysis for fly ash transport water, bottom ash transport water, and flue gas mercury control wastewater because limitations for these wastestreams for direct dischargers consist of no discharge of process wastewater pollutants to waters of the U.S., and therefore, all pollutants "pass through" the POTW for these wastestreams.

FGD Wastewater

The technology basis for PSES and PSNS for FGD discharges is one-stage chemical precipitation followed by biological treatment. Table 11-4 presents the treatment technology percent removals and POTW removals for FGD wastewater. Because the proposed FGD wastewater BAT and NSPS limitations/standards for arsenic and mercury were transferred from the one-stage chemical precipitation system, EPA performed the pass-through analysis for arsenic and mercury based on the pollutant removals achieved by the one-stage chemical precipitation system. All five regulated pollutants were determined to pass through POTW secondary treatment and EPA selected them as regulated pollutants for PSES/PSNS.

Table 11-4. POTW Pass-Through Analysis (FGD Wastewater) – PSES/PSNS

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	99.5%[a]	65.8%	Yes	Yes
Mercury	99.9%[a]	90.2%	Yes	Yes
Nitrate, Nitrite as N	99.6%	90.0%	Yes	Yes
Selenium	99.9%	34.3%	Yes	Yes

a – The arsenic and mercury BAT percent removals are based on the one-stage chemical precipitation treatment, because the proposed BAT effluent limitations were transferred from the one-stage chemical precipitation system.

Combustion Residual Leachate

The technology basis for PSES and PSNS for combustion residual leachate, under Regulatory Options 4 and 5, is chemical precipitation. As explained further in Section 13, EPA is transferring the limitations/standards for leachate from the one-stage chemical precipitation technology option for FGD wastewater. Therefore, for arsenic and mercury, the technology basis percent removals for leachate are based on the removals achieved by the one-stage chemical precipitation system for FGD wastewater. Table 11-5 presents the treatment option percent removals and POTW removals for combustion residual leachate using the methodology described above. Both mercury and arsenic pass through and EPA is proposing them for regulation under PSES and PSNS.

Table 11-5. POTW Pass-Through Analysis (Combustion Residual Leachate) – PSES/PSNS

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	99.5 %[a]	65.8%	Yes	Yes
Mercury	99.9% [a]	90.2%	Yes	Yes

a – The arsenic and mercury BAT percent removals are based on FGD wastewater one-stage chemical precipitation treatment, because the proposed BAT effluent limitations were transferred from the FGD wastewater one-stage chemical precipitation system.

Gasification Wastewater

The technology option for gasification is vapor-compression evaporation. Table 11-6 presents the technology option percent removals and POTW removals for gasification wastewater. All four regulated pollutants were determined to pass through POTW secondary treatment and EPA is proposing them for PSES and PSNS.

Table 11-6. POTW Pass-Through Analysis (Gasification Wastewater) – PSES/PSNS

Pollutant	Median BAT % Removal	POTW % Removal	BAT % Removal > POTW % Removal?	Does Pollutant Pass Through?
Arsenic	99.4%	65.8%	Yes	Yes
Mercury	98.5%	90.2%	Yes	Yes
Selenium	88.9%	34.3%	Yes	Yes
TDS	99.7%	0%	Yes	Yes

11.3 REFERENCES

1. Metcalf & Eddy, Inc. 2003. *Wastewater Engineering, Treatment and Reuse, Fourth Edition*. McGraw-Hill. New York. DCN SE02936.
2. U.S. EPA. 1976. Supplement for Pretreatment to the Development Document for the Steam Electric Power Generating Point Source Category. EPA 440/1-76/084. Washington, D.C. (November). DCN SE02935.

SECTION 12
NON-WATER QUALITY ENVIRONMENTAL IMPACTS

The elimination or reduction of one form of pollution has the potential to aggravate other environmental problems, an effect frequently referred to as cross-media impacts. Sections 304(b) and 306 of the Clean Water Act require EPA to consider non-water quality environmental impacts (NWQIs), including energy requirements, associated with effluent limitations guidelines and standards (ELGs). Accordingly, EPA has considered the potential impacts of the proposed regulation on energy consumption, air emissions, and solid waste generation and management.[101] EPA determined that the proposed ELGs have non-water quality environmental impacts associated with operations for treating and managing FGD wastewater, combustion residual landfill leachate, and ash transport water. However, because all plants generating flue gas mercury control wastewater and gasification wastewater currently operate the technologies identified as the basis for BAT, EPA does not predict any net increase of energy or fuel usage, sludge generation, or air emissions for these wastestreams for the proposed ELGs. Additionally, because all plants generating and discharging nonchemical metal cleaning wastes are either already meeting the proposed BAT limitations (based on the current BPT standard) or will be exempt from the proposed BAT limitations, EPA does not predict any net increase of energy or fuel usage, sludge generation, or air emissions for nonchemical metal cleaning wastes for the proposed ELGs. As described throughout this section, although the regulatory options will result in increases of energy and fuel usage, sludge generation, and air emissions, the increases are small compared to national levels of energy/fuel usage, current air emissions from power plants, and sludge production from municipal wastewater treatment plants.[102]

12.1 ENERGY REQUIREMENTS

Steam electric power plants use energy when transporting ash and other solids on or off site, operating wastewater treatment systems (e.g., chemical precipitation, biological treatment), operating ash handling systems, or operating water trucks for dust suppression. For those plants that EPA projected would incur costs to comply with the regulatory options, EPA considered whether or not there would be an associated incremental energy need. That need varies depending on the regulatory option evaluated and the current operations of the plant. Therefore, as applicable, EPA estimated the additional energy usage in megawatt hours (MWh) for equipment added to the plant systems or in consumed fuel (gallons) for transportation/operating equipment. Similarly, as applicable, EPA also estimated the decrease in energy requirements resulting from the reduction in wet sluicing operations and use of earth-moving equipment. EPA scaled the plant-specific estimate to calculate the net change in energy requirements for the regulatory options for this proposed rulemaking.

To determine potential increases in electrical energy use, EPA estimated the amount of energy needed to operate wastewater treatment systems and ash handling systems. To determine

[101] EPA also evaluated the increases of energy and fuel usage, sludge generation, and air emissions for the future profile population and new sources. For more information on the NWQI EPA evaluated for future profile and new sources, see EPA's memorandum "Evaluation of NWQI for the Future Profile Population and New Sources" [U.S. EPA, 2012b].

[102] The proposed regulatory options will also result in decreases of air emissions for certain pollutants.

potential decreases in electrical energy use, EPA estimated the amount of energy saved from reducing wet sluice pumping operations based on the horsepower rating of the pumps. Similarly, EPA estimated the amount of energy saved by reducing the number of backhoes needed to dredge solids from ash impoundments, resulting from the reduction of wet sluice operations. EPA estimated these energy savings using the horsepower rating of the backhoe engine. EPA only estimated energy savings associated with earthmoving equipment for plants operating surface impoundments. See EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more information on the specific calculations used to estimate energy. [U.S. EPA, 2013] Table 12-1 presents the net change in annual electrical energy usage associated with the proposed regulation.

Table 12-1. Industry-Level Energy Requirements by Regulatory Option

Regulatory Option	Electrical Energy Usage (MWh/year)	Fuel (GPY)
1	84,333	172,205
3a	112,004	2,867,770
2	191,327	173,421
3b	160,753	2,903,656
3	303,332	3,041,191
4a	472,369	4,617,848
4	673,780	6,027,266
5	2,835,389	7,548,543

Energy usage also includes the fuel consumption associated with transportation. EPA estimated the need for increased transportation of ash and other solid waste, including wastes from the treatment of FGD wastewater and landfill leachate, at steam electric power plants to on-site or off-site landfills, based on plant-specific data, using open dump trucks. In general, the fuel usage was calculated as shown:

$$\text{Fuel (gallons)}_{\text{plant}} = [((\text{Loading Time (hr/trip)}_{\text{idling}} + \text{Unloading Time (hr/trip)}_{\text{idling}}) \times (\text{Fuel Consumption (gal/hr)}_{\text{idling}})) + (\text{Transport Distance (mile/round trip)} \times \text{Fuel consumption (gal/mile)})] \times (\text{Number of Trips (trips/yr)})$$

Where:

Loading Time (hr/trip)	=	The estimated time to load an open dump truck with sludge and/or ash per trip, estimated to be 0.1667 hours (10 minutes) per trip.
Unloading Time (hr/trip)	=	The estimated time to unload an open dump truck with sludge and/or ash per trip, estimated to be 0.1667 hours (10 minutes) per trip.
Fuel Consumption (gal/hr) $_{\text{idling}}$	=	The estimated fuel consumption while the truck is idling. The MOBILE6.2 vehicle emission

		modeling software assumes that dump trucks average 2.5 miles per hour and 6.6 miles per gallon at idle. Therefore, EPA estimated the idle fuel consumption to be 0.38 gal/hr.
Transport Distance (mile/round trip)	=	The estimated round trip distance to/from the landfill. Distance varies based on plants with onsite versus offsite landfills. For onsite landfills, EPA estimated a round trip to be 2.6 miles. For offsite landfills, EPA estimated a round trip to be 40 miles.
Fuel consumption (gal/mile)	=	The estimated fuel consumption while the truck is in drive, estimated to be 20.24 gal/100 miles.
Number of Trips (trips/yr)	=	The calculated number of trips for one year in the transportation methodology to truck all ash to the onsite or offsite landfill.

The frequency and distance of transport depends on a plant's operation and configuration. For example, the volume of waste generated per day determines the frequency with which trucks will be travelling to and from the storage sites. The availability of either an on-site or off-site non-hazardous landfill and its distance from the plant determines the length of travel time.

EPA also estimated fuel consumption associated with the dust suppression water trucks based on the total distance (in miles) traveled and the total number of hours estimated for water truck operations. See EPA's *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more information on the specific calculations used to estimate transportation fuel usage. [U.S. EPA, 2012c] Table 12-1 shows the net change in national annual fuel consumption associated with the proposed regulation.

To provide some perspective on the potential net increase in annual electric energy consumption associated with the preferred options, EPA compared the estimated increase in energy usage (MWh), as shown in Table 12-1, to the net amount of electricity generated in a year by all electric power plants throughout the United States. According to EPA's Emissions & Generation Resource Integrated Database (eGRID), the electric power industry generated approximately 3,951 million MWh of electricity in 2009. EPA estimates that energy increases associated with the preferred BAT and PSES regulatory options range from less than 0.003 percent (Option 3a) to 0.012 percent (Option 4a) of the total electricity generated by all electric power plants.

Similarly, EPA compared the additional net fuel consumption (gallons) estimated for the preferred options, as shown in Table 12-1, to national fuel consumption estimates for motor vehicles. According to the U.S. Energy Information Administration (EIA), on-highway vehicles, which include automobiles, trucks, and buses, consumed approximately 34 billion gallons of distillate fuel oil in 2009. EPA estimates that the fuel consumption increase associated with the proposed Option 3a for BAT and PSES will be 0.008 percent of total fuel consumption by all motor vehicles. Fuel consumption is estimated to increase by less than 0.009 percent under Options 3b and Option 3, and less than 0.014 percent under Option 4a.

12.2 AIR EMISSIONS POLLUTION

The proposed ELGs are expected to affect air pollution through three main mechanisms:

Additional auxiliary electricity use by steam electric plants to operate wastewater treatment, ash handling, and other systems needed to comply with the new effluent limitations and standards;

Additional transportation-related emissions due to the increased trucking of combustion residual waste to landfills; and

The change in the profile of electricity generation due to relatively higher costs to generate electricity at plants incurring compliance costs for the proposed rule.

This section provides greater detail on air emission changes associated with the first two mechanisms and presents the estimated net change in air emissions that take all three mechanisms into account. See EPA's *Benefit and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Categor*y report for additional discussion of the third mechanism.

Air pollution is generated when fossil fuels are combusted. In addition, steam electric power plants generate air emissions from the operating transport vehicles, such as dump trucks and vacuum trucks, dust suppression water trucks, and earth-moving equipment, which release criteria air pollutants and greenhouse gases when operated. Criteria air pollutants are those pollutants for which a national ambient air quality standard (NAAQS) has been set and include sulfur dioxide (SO_2) and nitrogen oxides (NOx). Greenhouse gases are gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) that absorb radiation, thereby trapping heat in the atmosphere, and contributing to global warming.[103] Similarly, a decrease in energy use or vehicle operation will result in decreased air pollution.

EPA estimated the energy usage associated with the operation of wastewater treatment systems and ash handling systems in megawatt hours (MWh). Additionally, EPA also estimated the decrease in energy requirements associated with terminating wet sluicing operations and reduced use of earth-moving equipment associated with the new technology options. EPA used these estimates to calculate the net change in energy requirements for all regulatory options considered for this proposed rulemaking.

EPA calculated air emissions resulting from increased auxiliary electricity using year-explicit emission factors projected in IPM for CO_2, NO_x, and SO_2. EPA obtained emission factors for years 2017 through 2024 based on IPM outputs for Run Year 2020 and emission

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

factors for years 2025 through 2040 based on IPM output for Run Year 2030. EPA used the values associated with Run Year 2030 because these values represent full implementation of the proposed rule. Table 12-2 presents the IPM emission factors for Regulatory Options 3 and 4 for CO_2, NO_x, and SO_2 by NERC region, as well as the average for the United States.

Table 12-2. Summary of IPM Emissions Factors by NERC Region and Across Steam Electric Plants

Run Year	NERC Region / Plants	Option 3			Option 4		
		CO2	NOx	SO2	CO2	NOx	SO2
		Metric Tonnes / MWh	Tons / MWh	Tons / MWh	Metric Tonnes / MWh	Tons / MWh	Tons / MWh
2020	**US**	**0.5324**	**0.0004**	**0.0005**	**0.5322**	**0.0004**	**0.0005**
	ERCOT	0.5599	0.0003	0.0003	0.5610	0.0003	0.0003
	FRCC	0.5031	0.0003	0.0003	0.5051	0.0003	0.0003
	MRO	0.6892	0.0008	0.0008	0.6902	0.0008	0.0008
	NPCC	0.2694	0.0002	0.0002	0.2694	0.0002	0.0002
	RFC	0.5904	0.0005	0.0007	0.5904	0.0005	0.0007
	SERC	0.5674	0.0004	0.0006	0.5674	0.0004	0.0006
	SPP	0.7290	0.0006	0.0007	0.7290	0.0006	0.0007
	WECC	0.3772	0.0005	0.0002	0.3772	0.0005	0.0002
2030	**US**	**0.5210**	**0.0004**	**0.0005**	**0.5204**	**0.0004**	**0.0005**
	ERCOT	0.5411	0.0003	0.0002	0.5408	0.0003	0.0002
	FRCC	0.4782	0.0003	0.0002	0.4781	0.0003	0.0002
	MRO	0.6555	0.0007	0.0008	0.6555	0.0007	0.0008
	NPCC	0.2980	0.0002	0.0002	0.2979	0.0002	0.0002
	RFC	0.5764	0.0005	0.0006	0.5764	0.0005	0.0006
	SERC	0.5604	0.0004	0.0006	0.5604	0.0004	0.0006
	SPP	0.7130	0.0006	0.0007	0.7130	0.0006	0.0007
	WECC	0.3645	0.0004	0.0001	0.3645	0.0004	0.0001

For plants with capacity utilization rates (CUR) of 90.4 percent or less, EPA estimated emissions using plant-specific and year-explicit emission factors obtained from IPM outputs.[104] These plants are assumed to be able to generate the additional auxiliary electricity on site.

For plants with CUR greater than 90.4 percent, EPA used NERC-average emission factors for each year instead of plant-specific emissions factors. EPA used these NERC-average factors based on the assumption that additional electricity consumption for auxiliary power will displace grid power within the region instead of coming from additional generation at the plant (i.e., the plant will be using part of its existing generation to power equipment, requiring other plants within the same NERC region to generate additional electricity to meet demand).

EPA calculated NO_X emissions as follows:

$$NOX_t = \sum_{p=1}^{733} E_p \times EF\_NOX_{p,t} \times T_{p,t} \times W_p$$

Where:

NOX_t	=	Total NO_x emissions in year *t*.
E_p	=	Incremental auxiliary power electricity consumption at plant *p*, in MWh per year.
$EF\_NOX_{p,t}$	=	NO_x emission factor at plant *p* in year *t*, in tons NO_x per MWh. If CUR_p > 90.4 percent, $EF\_NOX_{p,t}$ is based on average EF_NOX_t for the NERC region where plant *p* is located. For *t* = 2017 to 2024, the calculations use IPM $EF\_NOX_{p,2020}$. For *t* = 2025 to 2040, the calculations use IPM $EF\_NOX_{p,2030}$.
$T_{p,t}$	=	Timing adjustment to reflect year when plants are assumed to install the compliance technology between 2017 and 2021 and start incurring additional electricity consumption ($T_{p,t}$ =0 if t < Year when plant *p* installs technology; $T_{p,t}$ =1 if $t \geq$ Year when plant *p* installs technology).
W_i	=	Sample weight for plant *p*.

Emissions of CO_2 and SO_2 are calculated similarly but using the CO_2 and SO_2 emission factors, respectively.

Since IPM was run for Regulatory Options 3 and 4 only, EPA used IPM emission factors for Option 3 to estimate changes in auxiliary power air emissions for Options 1 and 2, and IPM emissions factors for Option 4 to estimate changes in auxiliary power air emissions for Option 5. EPA used the auxiliary power air emissions calculated for Option 1 through 5 to estimate the auxiliary power air emissions for Options 3a, 3b, and 4a. For additional details on these estimation methodologies, see the memoranda entitled "Memorandum to the Rulemaking

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

Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Options 3a and 3b" and "Memorandum to the Rulemaking Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a" [ERG, 2013a; ERG, 2013b].

To estimate air emissions associated with increased operation of transport vehicles, EPA used the MOBILE6.2 model to generate air emission factors (grams per mile) for hydrocarbons (HC), carbon monoxide (CO), NOx, CO_2, and particulate matter (PM). 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. See EPA's report entitled *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more specific information on the assumptions made by EPA for year of the vehicle and annual mileage accumulation. [U.S. EPA, 2012c] Because MOBILE6.2 does not estimate emission factors for CH_4, EPA used the emission factors from the California Climate Action Registry, General Reporting Protocol, Version 2.2. Table 12-3 provides a table of the transportation emission factors for each air pollutant considered in the NWQI analysis.

Table 12-3. MOBILE6.2 and California Climate Action Registry Transportation Emission Rates

Nitrogen Oxides Highway (ton/mi)	Nitrogen Oxides Local (ton/mi)	Sulfur Oxides (ton/mi)	Carbon Dioxide (ton/mi)	Methane (ton/mi)
6.76×10^{-7}	6.52×10^{-7}	1.58×10^{-8}	0.0017	6.61×10^{-8}

Source: MOBILE6.2 [U.S. EPA, 2004] and California Climate Action Registry, General Reporting Protocol, V2.2 [California Climate Action Registry, 2007]

Note: The MOBILE6.2 highway and local emission rates are the same for all pollutant except nitrogen oxides.

Using the transportation emission rates per mile, EPA calculated the air emissions associated with the additional energy estimated for the regulatory options, as shown:

$$\text{Emission (tons)}_{\text{pollutant x, plant}} = (\text{Air Emission Factor (ton/mile)}_{\text{pollutant x, vehicle}}) \times (\text{Transport Distance (mile/round trip)}) \times (\text{Number of Trips (trips/yr)}).$$

Where:

Air Emission Factor (ton/mile) $_{\text{pollutant x, vehicle}}$	=	The transportation emission factor for each pollutant presented in Table 12-3.
Transport Distance (mile/round trip)	=	The estimated round trip distance to/from the landfill. Distance varies based on plants with on-site versus off-site landfills. For on-site landfills, EPA estimated a round trip to be 2.6 miles. For off-site landfills, EPA estimated a round trip to be 40 miles.

Number of Trips (trips/yr) = The calculated number of trips for one year in the transportation methodology to truck all ash to the on-site or off-site landfill.

EPA estimated the annual number of miles that would be traveled by dump trucks or vacuum trucks moving ash or wastewater treatment solids to on- or off-site landfills related to the regulatory options. In addition to the trucks associated with transporting the additional solid waste, EPA also estimated the annual number of miles that would be traveled by water trucks spraying water around landfills and ash unloading areas to control dust. EPA used these estimates to calculate the net increase in air emissions for this rulemaking. See EPA's report entitled *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more information. [U.S. EPA, 2012c] The increases in national annual air emissions associated with auxiliary electricity and transportation for each of the regulatory options are shown in Table 12-4 [ERG, 2013c].

Table 12-4. Industry-Level Air Emissions Associated with Auxiliary Electricity and Transportation by Regulatory Option

Regulatory Option	Air Emissions			
	NO_X (tons/year)	SO_X (tons/year)	CO_2 (metric tons/year)	CH_4 (tons/year)
1	54	90	79,753	1.2
3a	88	84	117,863	2.4
2	119	190	181,366	2.7
3b	113	126	164,318	3.1
3	207	274	299,229	5.1
4a	321	418	459,074	7.9
4	547	709	663,957	11
5	1,772	2,708	2,674,207	41

EPA estimated the change in the profile of electricity generation due to relatively higher costs to generate electricity at plants incurring compliance costs for the proposed rule using data from IPM. IPM predicts changes in electricity generation due to compliance costs attributable to the proposed ELG options. Therefore, EPA predicts that these changes, either increases or decreases, in electricity generation affect the air emissions from steam electric power plants. EPA only estimated the changes associated with the IPM predications, one of the three air emission mechanisms, for Option 3 and 4. The net changes in national annual air emissions associated with the preferred options are shown in Table 12-5.

Table 12-5. Industry-Level Net Air Emissions For the Preferred Regulatory Options

Regulatory Option	Air Emissions			
	NO_x (tons/year)	SO_x (tons/year)	CO_2 (metric tons/year)	CH_4 (tons/year)
3a	88-1,090[a]	<84[b]	<117,863[b]	2.4
3b	110-1,110[a]	<130[b]	<164,318[b]	3.1
3	1,207	-2,726	-1,162,771	5.1
4a	1,320[c]	<-2,580[c]	<-1,002,926[c]	7.9
4	1,547	-3,291	-3,749,043	11

a - EPA quantified the air emissions associated with additional electricity and additional transportation for Options 3a and 3b. Based on the values quantified for Option 3 for the changes to air emissions projected by IPM, EPA calculated the range of emissions for NOx. The lower end of the range represents the emissions only associated with additional electricity and transportation. The upper end of the range also includes the changes to air emissions projected by IPM (based on Option 3), which are large than would be expected for Option 3a and 3b.

b - EPA quantified the air emissions associated with additional electricity and additional transportation for Options 3a and 3b. Based on the values quantified for Option 3 for the changes to air emissions projected by IPM, which were negative, EPA decided not to include these IPM air emission changes in the calculated SOx and CO_2 emissions for Options 3a and 3b. These SOx and CO_2 emissions are considered maximum values because EPA expects that the air emission changes projected by IPM for Options 3a and 3b will also be negative (as they are for Options 3 and 4).

c - EPA quantified the air emissions associated with additional electricity and additional transportation for Option 4a. To estimate the total emissions for Option 4a, EPA added the changes to air emissions projected by IPM for Option 3 because they are more conservative (i.e., they overestimate the emissions). The contribution of NOx is unchanged compared to Option 3 and 4; therefore, EPA assumed this would also be the contribution for Option 4a. For SOx and CO_2, the contribution associated with Option 4 are lower (i.e., more negative); therefore, because EPA used the Option 3 values, the values presented in the table are maximum values.

To provide some perspective on the potential increase in annual air emissions associated with the preferred options, EPA compared the estimated increase in air emissions associated with Regulatory Options 3a, 3b, 3, 4a, and 4 to the net amount of air emissions generated in a year by all electric power plants throughout the United States. Table 12-6 presents the 2009 emissions generated by the electric power industry, based on eGRID, and the percent of increased emissions associated with the proposed rule. [U.S. EPA, 2012a]

Table 12-6. Electric Power Industry Air Emissions

Non-Water Quality Impact	Value Associated with Preferred Regulatory Option (Million Tons)	2009 Emissions by Electric Power Industry (Million Tons)	Increase In Emissions (%)
Regulatory Option 3a			
NO_x	0.000088-0.00109	1	0.008-0.109
SO_x	<0.000084	6	<0.0014
CO_2	<0.130	2,403	<0.0054
CH_4	0.0000024	95	0.0000025
Regulatory Option 3b			
NO_x	0.00011-0.00111	1	0.011-0.111
SO_x	<0.00013	6	<0.0021
CO_2	<0.181	2,403	<0.0075
CH_4	0.0000031	95	0.0000033
Regulatory Option 3			
NO_x	0.00121	1	0.121
SO_x	-0.00273	6	-0.045
CO_2	-1.282	2,403	-0.053
CH_4	0.000001	95	0.000001
Regulatory Option 4a			
NO_x	0.00132	1	0.132
SO_x	<-0.00258	6	<-0.043
CO_2	<-1.106	2,403	<-0.046
CH_4	0.0000079	95	0.0000083
Regulatory Option 4			
NO_x	0.00154	1	0.154
SO_x	-0.00329	6	-0.055
CO_2	-4.133	2,403	-0.172
CH_4	0.000001	95	0.000001

12.3 Solid Waste Generation

Steam electric power plants generate solid waste associated with sludge from wastewater treatment systems (e.g., chemical precipitation, biological treatment). The regulatory options evaluated would increase the amount of solid waste generated from FGD wastewater treatment, including sludge from chemical precipitation, biological treatment, and vapor-compression evaporation technologies. EPA estimated the amount of solid waste generated from each technology for each plant and estimates that the preferred BAT/PSES regulatory options (Options 3a, 3b, 3, and 4a) would increase solids generated annually from treatment. Fly ash and bottom ash are also solid wastes generated at steam electric power plants. The preferred regulatory options for BAT and PSES are, however, not expected to alter the amount of fly ash, bottom ash, or other combustion residuals generated.

EPA determined dewatered sludge generation rates for chemical precipitation treatment by multiplying a flow-normalized dewatered sludge generation rate (expressed in tons per day of sludge per gallon per minute FGD flow) by the plant flow rate. The flow-normalized dewatered sludge generation rate was determined based on responses in the questionnaire for FGD wastewater chemical precipitation treatment. EPA selected the median flow-normalized dewatered sludge generation rate based on an assessment of the characteristics of the dataset. EPA then calculated the annual sludge generation as follows:

$$\text{Annual Sludge Generation, tons/yr} = \text{Sludge Generation Rate} \times \text{FGD Wastewater Flow, gpm} \times 60 \text{ min/hr} \times 24 \text{ hr/day} \times 365 \text{ day/year}$$

Where:

Sludge Generation Rate	=	The median flow normalized rate of sludge generation based on the questionnaire. EPA estimated this rate to be 0.24 tons per day per gallon per minute of FGD wastewater flow.
FGD Wastewater Flow	=	The FGD wastewater for the plant in units of gallons per minute. This value was calculated from the gallons per day value reported in the survey and divided by 24 x 60 to convert to gallons per minute.

Sludge generated by the biological treatment system is contained within the backwash wastewater which is recycled to the FGD wastewater chemical precipitation system and is ultimately removed with the chemical precipitation sludge. Sludge generated by the vapor-compression evaporation system includes softening sludge and crystallizer sludge. EPA obtained sludge generation rates for the softening sludge and crystallizer sludge based on FGD wastewater flow rates from equipment vendors. [HPD, 2009] Based on this information, EPA calculated sludge generation rates using the equations provided below.

$$\text{Softening Sludge, tons/yr} = \text{Softening Sludge Factor, lb/hr-gpm} \times \text{FGD Wastewater Flow, gpm} \times (1 \text{ ton}/2{,}000 \text{ lb}) \times 24 \text{ hpd} \times 365 \text{ dpy}$$

$$\text{Crystallizer Sludge, tons/yr} = \text{Crystallizer Sludge Factor, lb/hr-gpm} \times \text{FGD Wastewater Flow, gpm} \times (1 \text{ ton}/2{,}000 \text{ lb}) \times 24 \text{ hpd} \times 365 \text{ dpy}$$

Where:

Softening Sludge Factor	=	A factor that relates the amount of sludge generated in the softening process to the scrubber purge flow based on data provided by HPD, 51.43 lb/hr-gpm.
Crystallizer Sludge Factor	=	A factor that relates the amount of sludge generated in the crystallizer process to the scrubber purge flow based on data provided by HPD, 17.14 lb/hr-gpm.

See EPA's report entitled *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more information [U.S. EPA, 2012c]. The net change in national annual sludge production associated with the regulatory options is shown in Table 12-7.

To provide some perspective on the potential increase in annual solid waste generation associated with Regulatory Options 3a, 3, and 4a, EPA compared the estimated increase in solid waste generation to the amount of solids generated in a year by electric power plants throughout the United States. According to the EIA, power plants generated approximately 134 billion tons of solids in 2009. EPA estimates that solid waste generation increases associated with the preferred regulatory options will be less than 0.001 percent of the total solid waste generated by all electric power plants.

Table 12-7. Industry-Level Solid Waste Increases by Regulatory Option

Regulatory Option	Sludge (Tons/Year)
1	1,209,859
3a	0
2	1,218,691
3b	365,960
3	1,218,691
4a	1,218,691
4	1,459,011
5	13,281,443

12.4 REDUCTIONS IN WATER USE

Steam electric power plants generally use water for handling solid waste, including ash, and for operating wet FGD scrubbers. The technology options for fly ash and bottom ash will eliminate or reduce water use associated with current wet sluicing operating systems. EPA estimated the reductions in water use by calculating the amount of ash sluice water, specifically that amount of water identified as intake process water, that will no longer be discharged as part of the proposed rulemaking. In order to calculate this reduction, EPA used data from Part C of the Steam Electric Survey to calculate an average percentage of ash sluice water identified as intake water. EPA multiplied this percentage by the amount of sluice water discharged by each plant to calculate the estimated process water reduction. See the memorandum entitled "Steam Electric Effluent Guidelines Non-Water Quality Impacts" for more information [ERG, 2013c].

The technology basis for the preferred regulatory option with respect to FGD wastewater discharges (e.g., chemical precipitation, biological treatment) would not be expected to reduce the amount of water used unless plants recycle FGD wastewater as part of their treatment system. EPA estimated that five plants would be able to incorporate recycle within their FGD systems based on the maximum operating chlorides concentration compared to the design maximum chlorides concentration (other plants may also be able to do so). In order to estimate the water reductions associated with the recycled FGD wastewater, EPA used data from Part B of the Steam Electric Survey to calculate an average percentage of FGD wastewater identified as intake water. EPA multiplied this percentage by the amount of water that could be recycled by the FGD system to calculate the estimated water reduction. EPA also used the adjusted FGD scrubber purge flows to estimate compliance cost and pollutant loadings associated with these plants. See EPA's report entitled *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* for more information [U.S. EPA, 2012c].

EPA estimates that power plants would reduce the use of water associated with the regulatory options. Table 12-8 presents the expected reduction in process water use for each regulatory option evaluated for the proposed rule. For comparison, EPA compared the expected levels of process water reductions to the current amount of wastewater discharged from the wastestreams expected to have associated non-water quality environmental impacts for this proposed rulemaking, presented in Table 12-9.

Table 12-8. Industry-Level Process Water Reduction by Regulatory Option

Regulatory Option	Water Reduction (Million Gallons/Year)
1	2,820
3a	49,900
2	2,820
3b	52,100
3	52,700
4a	103,000
4	153,000
5	153,000

Table 12-9. Wastewater Discharge at Steam Electric Power Plants

Type of Wastewater	Number of Plants Discharging Wastewater	Total Wastewater Discharged (2009, Million Gallons/Year)
FGD Wastewater	117	23,700
Fly Ash Transport Water	95	81,100
Bottom Ash Transport Water	245	157,000
Landfill Leachate	100-115	2,200

12.5 REFERENCES

1. California Climate Action Registry. 2007. General Reporting Protocol: Reporting Entity-Wide Greenhouse Gas Emission, Version 2.2. (March). DCN SE02035.
2. Eastern Research Group (ERG). 2013a. Memorandum to the Rulemaking Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Options 3a and 3b. (19 April). DCN SE03881.

3. Eastern Research Group (ERG). 2013b. Memorandum to the Rulemaking Record: Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a. (19 April). DCN SE03834.
4. Eastern Research Group (ERG). 2013c. Memorandum to the Steam Electric Rulemaking Record. "Steam Electric Effluent Guidelines Non-Water Quality Impacts." (19 April). DCN SE02025.
5. U.S. EPA. 2004. MOBILE6.2 Vehicle Emission Modeling Software, available online at: http://www.epa.gov/oms/m6.htm.
6. U.S. EPA. 2012a. *The Emissions & Generation Resource Integrated Database for 2012 (eGRID 2012) Technical Support Document*. Available online at: http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012_year09_TechnicalSupportDocument.pdf. DCN SE02112.
7. U.S. EPA. 2012b. eGRID2012 Version 1.0 2009 Data. Available online at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html. DCN SE02111.
8. U.S. EPA. 2013. Incremental Costs and Pollutant Removals for Proposed Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category Report. (19 April). DCN SE01957.

SECTION 13 LIMITATIONS AND STANDARDS: DATA SELECTION AND CALCULATION

This section describes the data sources, data selection, and statistical methodology EPA used to calculate the long-term average, variability factors, and limitations and standards for existing and new sources. The effluent limitations guidelines and standards are based on long-term average effluent values and variability factors that account for variation in treatment performance within a particular treatment technology over time. For simplicity, in the remainder of this section, the proposed effluent limitations and/or standards are referred to as “limitations.” Also, the term “option long-term average” and “option variability factor” are used to refer to the long-term averages and variability factors for the treatment technology options for an individual wastestream rather than the regulatory options described in Section 8.1.

Section 13.1 provides a brief overview of the criteria EPA used to evaluate and select model plants (and the associated datasets) that are the basis of the proposed limitations. Section 13.2 describes the data exclusions and substitutions. Section 13.3 presents the procedures for data aggregation. Section 13.4 describes data editing criteria used to select plant datasets in developing the limitations. Sections 13.5 and 13.6 provide an overview and the procedure for estimation of the long-term averages, variability factors, and limitations. Section 13.7 describes the rationale for the transfer of limitations. Sections 13.8 and 13.9 provide the summary of the limitations and engineering review of the limitations.

13.1 DATA SELECTION

In developing the long-term averages, variability factors, and limitations for a particular wastestream and a particular technology option, EPA used wastewater data from plants operating the model technology as the basis for the technology option. The data sources evaluated include: (i) Sampling performed by EPA (hereafter referred to as “EPA sampling”) during which EPA collected samples; (ii) Sampling directed by EPA (hereafter referred to as “CWA 308 sampling”) during which EPA directed plants to collect samples; and (iii) Plants self-monitoring data (hereafter referred to as “plant self-monitoring”) collected by Duke Energy for two plants over a period of several years.

13.1.1 Data Selection Criteria

This section describes the criteria that EPA applied in selecting plants and data to use as the basis for the limitations for FGD, leachate, and gasification wastestreams. EPA has used these, or similar criteria, in developing limitations and standards for other industries. EPA uses these criteria to select data that reflect consistently good performance of the model technology in treating the industrial wastes under normal operating conditions. Generally, for each technology option, EPA has defined a treatment system (or management practices) comprised of specific components (e.g., equipment, chemical additives, etc.) that is carefully designed to operate under the expected wastestream characteristics (e.g., pollutant concentrations, flow rates, etc.) and that is diligently operated to achieve stable, optimized pollutant removal performance. Indicators of diligent operation include adequate staffing by trained personnel, frequent monitoring of treatment system operating conditions, and practice response to changes in operating conditions or indicators of system performance. The following paragraphs describe the criteria specific to the steam electric category.

The first criterion requires that the plant must have the model technology and demonstrate consistently diligent and optimal operation. Application of this criterion typically eliminates any plant with treatment other than the model technology. EPA generally determines whether a plant meets this criterion based upon site visits, discussions with plant management, and/or comparison to the characteristics, operation, and performance of treatment systems at other plants. EPA often contacts plants to determine whether data submitted were representative of normal operating conditions for the plant and equipment. EPA typically excludes the data in developing the limitations when the plant has not optimized the performance of its treatment system to the degree that represents the appropriate level of control (BAT or BADCT).

The second criterion generally requires that the influents and effluents from the treatment components represent typical wastewater from the industry, without incompatible wastewater from other sources. Application of this criterion results in EPA selecting only those plants where the commingled wastewaters were not characterized by substantial dilution, unequalized slug loads that resulted in frequent upsets and/or overloads, more concentrated wastewaters, or wastewaters with different types of pollutants than those generated by the wastestream for which EPA is establishing effluent limitations.

The third criterion typically ensures that the pollutants were present in the influent at sufficient concentrations to evaluate treatment effectiveness. To evaluate whether the data meet this criterion for the proposed rule, EPA often uses a long-term average test (or LTA test) for plants where EPA possesses paired influent and effluent data. EPA has used this test in developing regulations for other industries, e.g., the Iron and Steel Category (EPA 2002). The test measures the influent concentrations to ensure a pollutant is present at sufficient concentration to evaluate treatment effectiveness. If a dataset for a pollutant fails the test (i.e., not present at a treatable concentration), EPA excludes the data for that pollutant at that plant when calculating the limitations. See Section 13.4 for a detailed discussion of the LTA test.

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

The fourth criterion also is applied in EPA's review of data corresponding to the start-up or initial commissioning period for treatment systems. Most industries incur commissioning periods associated with installing new treatment systems to acclimate and optimize the system. During this acclimation and optimization process, the effluent concentration values tend to be highly variable with occasional extreme values (high and low). This occurs because the treatment system typically requires some "tuning" as the plant staff and equipment and chemical vendors work to determine the optimum chemical addition locations and dosages, vessel hydraulic residence times, internal treatment system recycle flows (e.g., filter backwash frequency, duration and flow rate; return flows between treatment system components), and other operational conditions including clarifier sludge wasting protocols. It may also take several weeks or months for treatment system operators to gain expertise on operating the new treatment system, which also contributes to treatment system variability during the commissioning period. After this initial adjustment period, the systems should operate at steady state with relatively low variability around a long-term average over many years. Because commissioning periods typically reflect one-time operating conditions unique to the first time the treatment system begins operation, EPA generally excludes such data in developing the limitations.[105]

13.1.2 Data Selection for Each Technology Option

This section discusses the data selected for use in developing the limitations for each pollutant for each technology option. This section includes an abbreviated description of the technology options. See Section 8.1.2 for a more complete discussion of the technology basis of the options considered.

For fly ash transport water and flue gas mercury control (FGMC) wastewater, all of the preferred regulatory options propose zero discharge of pollutants based on dry handling technologies; therefore, no effluent concentration data were used to set the limitations for these wastestreams.[106] This is also true for the regulatory options that include zero discharge of pollutants for any set of dischargers for bottom ash. For nonchemical metal cleaning wastes, EPA is proposing to establish limitations that are equal to the current BPT limitations that apply to discharges of nonchemical metal cleaning wastes from existing sources that are direct dischargers. No new effluent concentration data were used to set the effluent limitations for nonchemical metal cleaning wastes in this rulemaking, therefore, the limitations for this wastestream are not discussed in this section. For combustion residual leachate (hereafter referred to in this section as leachate) limitations based on the chemical precipitation technology option, EPA is proposing to transfer the limitations calculated based on the chemical precipitation technology option for FGD wastewater because EPA does not have available effluent data for leachate from plants employing the chemical precipitation technology. For the limitations based on the biological treatment technology option for FGD wastewater, EPA is

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

[106] EPA also considered a technology option that would require zero discharge of pollutants in bottom ash transport water. This technology option would be based on bottom ash handling practices that do not use water to carry the ash away from the boiler or that operate wet sluicing systems as closed-loop systems that do not discharge wastewater; therefore, no effluent concentration data would be used to set a zero discharge limitation for bottom ash transport water.

proposing to transfer the limitations for two pollutants (arsenic and mercury) calculated based on the chemical precipitation technology option for the FGD wastewater for the reasons described in Section 13.7.2. See Section 13.7 for a detailed discussion of the transfer of limitations.

Under some regulatory options being proposed, EPA would establish limitations for certain wastewater discharges that are equal to current BPT limitations for those dischargers. No new effluent concentration data would be used to establish BAT/NSPS limitations that are set equal to BPT, therefore, such limitations are not discussed in this section. See Section 8 for a more complete discussion of the basis for the proposed regulatory options.EPA used specific data sources to set the limitations for the different FGD wastewater treatment technologies and for gasification wastewater treatment. The data sources used to calculate effluent limitations for each technology option are described below.

FGD Wastewater

As part of the EPA sampling program and additional plant self-monitoring data EPA obtained during the rulemaking, EPA evaluated the performance of 10 FGD wastewater treatment systems. For seven of the 10 systems, EPA collected data representing the influent and effluent for chemical precipitation treatment system. EPA evaluated these seven systems and determined that the systems operating the chemical precipitation system with both hydroxide and sulfide precipitation achieved better removals of mercury compared to the plants that used only hydroxide precipitation. Therefore, EPA did not use data from the three plants that use only hydroxide precipitation. Four of the seven plants use hydroxide and sulfide precipitation; however, one of the plants operates a two-stage chemical precipitation system. Because EPA's basis for the technology option is a one-stage system, EPA did not use the data from the two-stage system in developing the limitations.[107] Therefore, EPA used data from the following three plants to develop the limitations based on treatment of FGD wastewater using the chemical precipitation technology option (i.e., one-stage chemical precipitation system employing both hydroxide and sulfide precipitation and iron coprecipitation, as well as flow reduction at plants with large FGD wastewater flow rates, hereafter referred to in this section as "chemical precipitation"– see Section 8.1.2.1 above for a more detailed description):

- Duke Energy's Miami Fort Station (hereafter referred to as Miami Fort);
- RRI Energy's Keystone Generating Station (hereafter referred to as Keystone); and
- Allegheny Energy's Hatfield's Ferry Power Station (hereafter referred to as Hatfield's Ferry).

For the treatment of FGD wastewater using a system that also includes a biological treatment system (chemical precipitation system followed by anoxic/anaerobic biological treatment to remove selenium, hereafter referred to as "biological treatment"), EPA evaluated the

[107] Based on data EPA has evaluated for the steam electric industry and other industry sectors, two-stage chemical precipitation systems generally achieve better pollutant removals than one-stage systems. Since the technology basis for chemical precipitation treatment of FGD wastewater in the proposed rule is a one-stage system and that is the configuration used to estimate compliance costs, EPA concluded that effluent data for the two-stage system (Pleasant Prairie) should not be used when calculating effluent limits for the technology option.

treatment systems that include biological treatment at three power plants as part of the EPA sampling program.[108] EPA determined that one of the biological treatment systems was not designed for effective removal of selenium and does not represent the model technology. Because EPA's basis for the technology option includes anoxic/ anaerobic biological treatment to remove selenium, EPA did not use data from this system in developing the limitations.

Therefore, EPA used data from the following two plants to develop the limitations and standards for the treatment of FGD wastewater using a one-stage chemical precipitation system followed by biological treatment:[109]

- Duke Energy Carolina's Belews Creek Steam Station (hereafter referred to as Belews Creek); and
- Duke Energy Carolina's Allen Steam Station (hereafter referred to as Allen).

For the treatment of FGD wastewater using chemical precipitation followed by a vapor-compression evaporation system, hereafter referred to as a "vapor-compression evaporation" system (which is the technology serving as the basis for Regulatory Option 5), EPA evaluated three systems as part of the EPA sampling program. One plant operates a system that is similar to the technology basis for the FGD wastewater limitations in the proposed rule: a one-stage chemical precipitation system followed by softening and a vapor-compression evaporation system. EPA used the data from this plant to develop the limitations based on the vapor-compression evaporation technology for the treatment of the FGD wastewater. That plant is Enel's Federico II Power Plant, located in Brindisi, Italy (hereafter referred to as Brindisi). EPA used data from a second plant for characterization purposes and not for limitations development because it only collected effluent data for one day from the plant. The third system does not represent the technology serving as the basis for the vapor-compression evaporation option, and was not used for the limitations development. This plant operates a solids removal process prior to the vapor-compression evaporation system but includes neither a full chemical precipitation system nor a softening step. Furthermore, this plant also operates a one-stage evaporation system and instead of employing a second stage of evaporation to crystallize and remove salts and other pollutants from the concentration brine, mixes the brine with fly ash and sends it to the landfill for disposal.

Gasification Wastewater

For the treatment of gasification wastewater using a vapor-compression evaporation system EPA evaluated systems from the following two plants as part of the EPA sampling program:

- Tampa Electric Company's Polk Station (hereafter referred to as Polk); and

[108] In the remainder of this section, the term "biological treatment" refers to chemical precipitation/iron coprecipitation (with both hydroxide and sulfide precipitation) followed by anoxic/anaerobic biological treatment.

[109] The limitations for arsenic and mercury for the biological (chemical precipitation followed by anoxic/anaerobic biological treatment) technology option were transferred from chemical precipitation technology option. See Section 13.7.2 for a detailed discussion of the transfer of the limitations.

- Wabash Valley Power Association's Wabash River Station (hereafter referred to as Wabash River).

Both systems are representative of the system used as the basis for the technology option and were used in calculating the limitations.

13.1.3 Combining Data from Multiple Sources within a Plant

Typically, if sampling data from a plant were collected over two or more distinct time periods, EPA analyzes the data from each time period separately. In past ELG rulemakings, where appropriate, EPA has analyzed the data as if each time period represents a different plant since these data can represent different operating conditions due to changes in management, personnel, and procedures. On the other hand, when EPA obtains the data (such as EPA sampling and plant self-monitoring data) from a plant during the same time period, EPA typically combines the data from these sources into a single dataset for the plant for the statistical analyses.

For this rulemaking, data for most of the plants came from multiple sources such as EPA sampling, CWA 308, or plant self-monitoring. For three plants (Allen, Belews Creek, and Hatfield's Ferry), the multiple sources of the data were collected during overlapping time periods, thus, EPA combined these data into a single dataset for the plant. For two plants (Keystone and Miami Fort), the multiple sources of the data were collected during non-overlapping time periods. However, in these instances the time period between the non-overlapping data collection periods was relatively small (two months). Furthermore, EPA has no information to indicate that the data represent different operating conditions. Thus, EPA also combined the multiple sources of data for each of these plants into a single dataset for the plant. This approach is consistent with EPA's traditional approach for other effluent guidelines rulemakings. Three plants (Brindisi, Polk, and Wabash River) had data from a single source, and for these plants it was not necessary to combine data. For a listing of all the data and their sampling sources for each of the plants, see the document entitled, "Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking." [U.S. EPA, 2012c].

13.2 DATA EXCLUSIONS AND SUBSTITUTIONS

The sections below describe the data exclusions and substitutions. Other than the data exclusions described in this section and the data excluded due to failing the data editing criteria (described in Section 13.4), EPA used all the data from the plants presented in Section 13.1.2.

13.2.1 Data Exclusions

Following EPA's selection of the model plant(s), EPA applied the criteria described above in Section 13.1.1 by thoroughly evaluating all available data for each model plant. EPA identified certain data that warranted exclusion from calculating the limitations because: (i) samples were analyzed using an insufficiently-sensitive analytical method (i.e., use of EPA Method 245.1 instead of Method 1631E for mercury); (ii) the samples were collected during initial commissioning period for the treatment system; or (iii) the analytical results were identified as questionable due to quality control issues, abnormal conditions or treatment upsets, or were analytical anomalies. See the memorandum entitled "Effluent Limitations for FGD

Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking" for a detailed discussion of the data that were excluded and a listing of the data excluded [U.S. EPA, 2012a].

13.2.2 <u>Data Substitutions</u>

In general, EPA used detected values or sample-specific detection limits (for non-detected values) in calculating the limitations.[110] However, there were some instances where EPA substituted a baseline value for a detected value or a sample-specific detection limit. The baseline value was used in the calculations to account for the possibility that certain a detected result may be at a lower concentration than can be reliably achieved by well-operated laboratories. This approach is consistent with the way EPA has calculated limitations in previous effluent guidelines rulemakings. After excluding all the necessary data as described in Section 13.2.1, EPA compared each reported result to a baseline value. When a detected value or sample-specific detection limit (i.e., sample specific quantitation limit) was lower than the baseline value, EPA used the baseline value instead and classified the value as non-detected (even if the actual reported result was a detected value). For example, if the baseline value was 10 ug/L and the laboratory reported a detected value of 5 ug/L, EPA's calculations would treat the sample result as being non-detected with a sample-specific detection limit of 10 ug/L.

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

- Arsenic: 2 ug/L;
- Mercury: 0.5 ng/L;
- Nitrate-nitrite as N: 0.05 mg/L;
- Selenium: 5 ug/L; and
- TDS: 10 mg/L.

EPA determined the baseline values for mercury, nitrate-nitrite as N, and TDS using the minimum levels (MLs) established by the analytical methods used to obtain the reported values or a comparable analytical method where an ML was not specified by the method.[111] The baseline values for arsenic and selenium are based on the results of method detection limit (MDL) studies conducted by well-operated commercial laboratories using EPA Method 200.8 to analyze samples of synthetic FGD wastewater. [CSC, 2013]

---

[110] For the purpose of the discussion of the calculation of the long-term averages, variability factors, and effluent limitations, the term "detected" refers to analytical results measured and reported above the sample-specific quantitation limit (QL). The term "non-detected" refers to values that are below the method detection limit (MDL) and also those measured by the laboratory as being between the MDL and the quantitation limit in the original data (before adjusting for baseline).

[111] The baseline values for mercury and nitrate-nitrite as N are equal to the MLs specified in EPA Methods 1631E and 353.2, respectively. The method EPA used to analyze for TDS (Standard Method 2540C) does not explicitly state a MDL or ML. However, EPA Method 160.1 is similar to Standard Method 2540C and the lower limit of its measurement range is 10 mg/L (i.e., the nominal quantitation limit). Thus, EPA used 10 mg/L as the baseline value for TDS.

In addition to calculating the limitations for each pollutant for each technology option adjusting for the baseline values, as described above, EPA also performed additional calculations to determine what the limitations would be using all valid reported results (i.e., without substituting baseline values and/or changing the classification of the result). The purpose of calculating the limitations using the data as reported is to allow a comparison between the limitations using baseline substitution and the limitations that would be obtained without the use of baseline substitution. For a detailed discussion of these calculations and the results, see the memorandum entitled, "Assessment of Effluent Limitations and Standards with No Baseline Substitution for the Steam Electric Rulemaking" [U.S. EPA, 2012b].

13.3 Data Aggregation

EPA used daily values in developing the limitations. In cases with at least two samples per day, EPA mathematically aggregated these samples to obtain a single value for that day (the procedure to aggregate the samples is described in subsections below). For the sampling data used in this rulemaking, there are instances when there are multiple sample results available for a given day. This occurred with field duplicates, overlaps between plant self-monitoring and EPA sampling, or overlaps between plant self-monitoring and CWA 308 sampling.

When aggregating the data, EPA took into account whether each value was detected (D) or non-detected (ND). Measurements reported as being less than the sample-specific detection limit (or baseline values, as appropriate) are designated as non-detected (ND) for the purpose of statistical analyses to calculate the limitations. In the tables and data listings in this document and in the rulemaking record, EPA uses the indicators D and ND denote the censoring type for detected and non-detected values, respectively.

The subsections below describe each of the different aggregation procedures. They are presented in the order that the aggregation was performed; i.e., field duplicates were aggregated first and then any overlaps between plant self-monitoring and EPA sampling data or CWA 308 sampling were aggregated.

13.3.1 <u>Aggregation of Field Duplicates</u>

During the EPA sampling episodes, EPA collected field duplicate samples as part of the quality assurance/quality control activities undertaken to ensure that the quality of the data collected is appropriate for their intended use. Field duplicates are two samples collected for the same sampling point at approximately the same time. The duplicates are assigned different sample numbers, and they are flagged as duplicates for a single sampling point at a plant. Because the analytical data from a duplicate pair are intended to characterize the same conditions at a given time at a single sampling point, EPA averaged the data to obtain one value for each duplicate pair.

In most cases, both duplicates in a pair had the same censoring type, so the censoring type of the aggregated value was the same as that of the duplicates. In some instances, one duplicate was a detected (D) value and the other duplicate was a non-detected (ND) value. When this occurred, EPA determined that the aggregated value should be treated as detected (D) because the pollutant is confirmed to be present at a level above the sample-specified detection limit in one of the duplicates. The document entitled "Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking" lists the data before the aggregation as well as after the aggregation [U.S. EPA, 2012c].

Table 13-1 below summarizes the procedure for aggregating the sample measurements from the field duplicates. The aggregation of the duplicate pairs was the first step in the aggregation procedures for both influent and effluent measurements.

Table 13-1. Aggregation of Field Duplicates

If the Field Duplicates Are:	Censoring Type of Average Is:	Value of the Aggregate Is:	Formulas for Aggregate Values of Duplicates
Both Detected	D	Arithmetic average of measured values.	$(D_1 + D_2)/2$
Both Non-Detected	ND	Arithmetic average of sample-specific detected limits (or baseline).	$(DL_1 + DL_2)/2$
One Detected and One Non-Detected	D	Arithmetic average of measured value and sample-specific detection limit (or baseline).	(D + DL)/2

D - detected.

ND - non-detected.

DL - sample-specific detection limit.

13.3.2 <u>Aggregation of Overlapping Samples</u>

At the Allen and Belews Creek plants, sampling data were available from EPA sampling, CWA 308 sampling, and plant self-monitoring. As explained in Section 13.1.3 above, there was some overlap between the data from these sources. On some days at a given plant, samples were available from two sources, specifically, plant self-monitoring and either EPA sampling or CWA 308 sampling. When these overlaps occurred, EPA aggregated the measurements from the available samples to obtain one value for that day. The document entitled "Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking" lists the data before the aggregation as well as after the aggregations [U.S. EPA, 2012c].

The procedure averaged the measurements to obtain a single value for that day. When both measurements had the same censoring type, then the censoring type of the aggregate was the same as that of the overlapping values. When one or more measurements were detected (D), EPA determined that the appropriate censoring type of the aggregate was detected because the pollutant is confirmed to be present at a level above the sample-specific detection limit in one of the samples. The procedure for obtaining the aggregated value and censoring type is similar to the procedure shown in Table 13-1.

13.4 DATA EDITING CRITERIA

After excluding and aggregating the data, EPA applied data editing criteria on a pollutant-by-pollutant basis to select the datasets to be used for developing the limitations for each technology option. These criteria are referred to as the long-term average test (or LTA test). EPA established the LTA test to ensure that the pollutants were present in the influent at sufficient concentrations to evaluate treatment effectiveness at the plant. The influent first had to pass a basic requirement that 50% of the influent measurements for the pollutants had to be detected at any concentration. If the dataset at a plant passed the basic requirement, then the data had to pass one of the following two criteria to pass the LTA test:

- Criterion 1. At least 50% of the influent measurements in a dataset at a plant were detected at levels equal to or greater than 10 times the baseline value (described in Section 13.2.2).
- Criterion 2. At least 50% of the influent measurements in a dataset at a plant were detected at any concentration and the influent arithmetic average was equal to or greater than 10 times the baseline value (described in Section 13.2.2).

If the dataset at a plant failed the basic requirement, then EPA automatically set both Criteria 1 and 2 to “fail”. If the dataset for a plant failed the basic requirement, or passed the basic requirement but failed both criteria, EPA would exclude the plant’s effluent data for that pollutant when calculating limitations. Through the application of the LTA test, EPA ensures that the limitations result from treatment of the wastewater and not simply the absence or substantial dilution of that pollutant in the wastestream.

After performing the LTA test for all the pollutants at each plant that was selected as the basis for the limitations for this rulemaking, it was found that all the datasets passed the LTA test except for arsenic and mercury data at Wabash River. Thus, data for arsenic and mercury at Wabash River were excluded from the calculation of the long-term average, variability factors, and limitations. See the memorandum entitled, “Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking” for the results of the LTA test for each pollutant at each plant [U.S. EPA, 2012a].

13.5 OVERVIEW OF LIMITATIONS

The preceding sections discussed the data selection, data exclusions and substitutions, data aggregation as well as the data editing procedures that EPA used to obtain the daily values for its calculations. This section describes EPA’s objectives for the daily maximum and monthly average effluent limitations, the selection of percentiles for those limitations, and compliance with the limitations.

13.5.1 Objectives

EPA’s objective in establishing daily maximum limitations is to restrict the discharges on a daily basis at a level that is achievable for a plant that targets its treatment at the long-term average. EPA acknowledges that variability around the long-term average occurs during normal operations. This variability means that plants may discharge at a level that is higher (or lower) than the long-term average. To allow for these possibly higher daily discharges, EPA has established the daily maximum limitation. A plant that consistently discharges at a level near the daily maximum limitation would not be operating its treatment to achieve the long-term average. Targeting treatment to achieve the daily maximum limitations, rather than the long-term average, may result in values that frequently exceed the limitations due to routine variability in treated effluent.

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

13.5.2 Selection of Percentiles

EPA calculates effluent limitations based upon percentiles that should be both high enough to accommodate reasonably anticipated variability within control of the plant, and low enough to reflect a level of performance consistent with the Clean Water Act requirement that these effluent limitations be based on the "best" available technologies. The daily maximum limitation is an estimate of the 99^{th} percentile of the distribution of the *daily* measurements. The monthly average limitation is an estimate of the 95^{th} percentile of the distribution of the *monthly* averages of the daily measurements. The percentiles for both types of effluent limitations are estimated using the products of long-term averages and variability factors.

EPA uses the 99^{th} and 95^{th} percentiles to draw a line at a definite point in the statistical distributions that would ensure that operators work to establish and maintain the appropriate level of control. These percentiles reflect a longstanding Agency policy judgment about where to draw the line. The development of the limitations takes into account the reasonable anticipated variability in discharges that may occur at a well-operated plant. By targeting its treatment at the long-term average, a well-operated plant should be capable of complying with the effluent limitations at all times because EPA has incorporated an appropriate allowance for variability in the limitations.

In conjunction with setting the limitations as described above, EPA performs an engineering review to verify that the limitations are reasonable based upon the design and expected operation of the control technologies and the plant process conditions. As part of the review, for each plant EPA compared the influent and effluent measurements with the limitations. See Section 13.8 below for details of these comparisons for each pollutant at each plant, as well as a discussion of the findings of the engineering review.

13.5.3 Compliance with Limitations

EPA promulgates limitations with which plants are capable of complying at all times by properly operating and maintaining their processes and treatment technologies. Commenters often raise the issue of exceedances or excursions (i.e., values that exceed the limitations) on limitations.

This issue was, in fact, raised in other rulemakings, including EPA's Organic Chemicals, Plastics, and Synthetic Fibers (OCPSF) rulemaking. EPA's general approach there for developing limitations based on percentiles is the same in this rule, and was upheld in the court ruling of *Chemical Manufacturers Association v. U.S. Environmental Protection Agency*, 870 F.2d 177, 230 (5th Cir. 1989). The Court determined that:

> EPA reasonably concluded that the data points exceeding the 99th and 95th percentiles represent either quality-control problems or upsets because there can be no other explanation for these isolated and extremely high discharges. If these data points result from quality-control problems, the exceedances they represent are within the control of the plant. If, however, the data points represent exceedances beyond the control of the industry, the upset defense is available.
> *Id. at 230.*

This issue was raised also in EPA's Phase I rule for the pulp and paper industry. In that rulemaking, EPA used the same general approach for developing limitations based on percentiles that it had used for the OCPSF rulemaking and for this proposed rule. This approach for the monthly average limitation was upheld in *National Wildlife Federation, et al v. Environmental Protection Agency*, No. 99-1452, Slip Op. at Section III.D (D.C. Cir.) (April 19, 2002). The Court determined that:

> EPA's approach to developing monthly limitations was reasonable. It established limitations based on percentiles achieved by plants using well-operated and controlled processes and treatment systems. It is therefore reasonable for EPA to conclude that measurements above the limitations are due to either upset conditions or deficiencies in process and treatment system maintenance and operation. EPA has included an affirmative defense that is available to mills that exceed limitations due to an unforeseen event. EPA reasonably concluded that other exceedances would be the result of design or operational deficiencies. EPA rejected Industry Petitioners' claim that facilities are expected to operate processes and treatment systems so as to violate the limitations at some pre-set rate. EPA explained that the statistical methodology was used as a framework to establish the limitations based on percentiles. These limitations were never intended to have the rigid probabilistic interpretation that Industry Petitioners have adopted. Therefore, we reject Industry Petitioners' challenge to the effluent limitations.

As the Court recognized, EPA's allowance for reasonably anticipated variability in its effluent limitations, coupled with the availability of the upset defense, reasonably accommodates acceptable excursions. Any further excursion allowances would go beyond the reasonable accommodation of variability and would jeopardize the effective control of pollutant discharges on a consistent basis. Further excursion allowances also could bog down administrative and enforcement proceedings in detailed fact finding exercises, contrary to Congressional intent. See, e.g., Rep. No. 92-414, 92d Congress, 2d Sess. 64, reprinted in A Legislative History of the Water Pollution Control Act Amendments of 1972 at 1482; Legislative History of the Clean Water Act of 1977 at 464-65.

More recently, for EPA's rule for the iron and steel industry, EPA's selection of percentiles was upheld in *American Coke and Coal Chemicals Institute v. Environmental Protection Agency*, 452 F.3d 930, 945 (D.C. Cir. 2006).

EPA expects that plants will comply with promulgated limitations *at all times*. If an exceedance is caused by an upset condition, the plant would have an affirmative defense to an enforcement action if the requirements of 40 CFR 122.41(n) are met. If the exceedance is caused by a design or operational deficiency, then EPA has determined that the plant's performance does not represent the appropriate level of control. For promulgated limitations and standards, EPA has determined that such exceedances can be controlled by diligent process and wastewater treatment system operational practices such as frequent inspection and repair of equipment, use of back-up systems, and operator training and performance evaluations.

13.6 CALCULATION OF THE LIMITATIONS

EPA calculated the limitations by multiplying the long-term average by the appropriate variability factors. In estimating the limitations for a pollutant, EPA first calculates an average performance level (the option long-term average discussed below) that a plant with well-designed and well-operated model technologies is capable of achieving. This long-term average is calculated using data from the plant or plants with the model technologies for the option.

In the second step of developing a limitation for a pollutant, EPA determines an allowance for the variation (the option variability factor discussed below) in pollutant concentrations for wastewater that has been processed through well-designed and well-operated treatment systems. This allowance for variation incorporates all components of variability including shipping, sampling, storage, and analytical variability. This allowance is incorporated into the limitations through the use of the variability factors which are calculated from the data from the plants using the model technologies. If a plant operates its treatment system to meet the relevant long-term average, EPA expects the plant will be able to meet the limitations. Variability factors ensure that normal fluctuations in a plant's treatment are accounted for in the limitations. By accounting for these reasonable excursions above the long-term average, EPA's use of variability factors results in effluent limitations that are generally well above the long-term averages.

The following sections describe the calculation of the option long-term averages, option variability factors and limitations, and the adjustment made for autocorrelation in the calculation of the limitations for each pollutant proposed for regulation.

13.6.1 Calculation of Option Long-Term Average

EPA calculated the option long-term average for a pollutant using two steps. First, EPA calculated the plant-specific long-term average for each pollutant that had enough distinct detected values by fitting a statistical model to the daily concentration values. In cases when a dataset for a specific pollutant did not have enough distinct detected values, then the statistical model was not used to obtain the long-term average. In these cases, the plant-specific long-term average for each pollutant was the arithmetic mean of the available daily concentration values. Appendix B contains the required minimum number of distinct detected observations and an overview of the statistical model and a description of the procedures EPA used to estimate the plant-specific long-term average.

Second, EPA calculated the option long-term average for a pollutant as the *median* of the plant-specific long-term averages for that pollutant. The median is the midpoint of the values when ordered (i.e., ranked) from smallest to largest. If there is an odd number of values, then the value of the m^{th} ordered observation is the median (where m=(n+1)/2 and n=number of values). If there are an even number of values, then the median is the average of the two values in the $n/2^{th}$ and $[(n/2)+1]^{th}$ positions among the ordered observations.

13.6.2 Calculation of Option Variability Factors and Limitations

The following describes the calculations performed to obtain the option variability factors and limitations. First, EPA calculated the plant-specific variability factors for each pollutant that had enough distinct detected values by fitting a statistical model to the daily concentration values. Each plant-specific daily variability factor for each pollutant is the estimated 99^{th} percentile of the distribution of the daily concentration values divided by the plant-specific long-term average. Each plant-specific monthly variability factor for each pollutant is the estimated 95^{th} percentile of the distribution of the 4-day average concentration values divided by the plant-specific long-term average. The calculation of the plant-specific monthly variability factor assumes that the monthly averages are based on the pollutant being monitored weekly (approximately four times each month). In cases when there were not enough distinct detected values for a specific pollutant, then the statistical model was not used to obtain the variability factors. In these cases, the data for the pollutant at the plant was excluded from the calculation of the option variability factors. Appendix B contains the required minimum number of distinct detected observations and a description of the procedures used to estimate the plant-specific daily and monthly variability factors.

Second, EPA calculated the option daily variability factor for a pollutant as the *mean* of the plant-specific daily variability factors for that pollutant. Similarly, the option monthly variability factor was the mean of the plant-specific monthly variability factors for that pollutant.

Finally, the daily maximum limitations for each pollutant for each technology option are the product of the option long-term average and option daily variability factors. The monthly average limitations for each pollutant for each technology option are the product of the option long-term average and option monthly variability factors.

13.6.3 Adjustment for Autocorrelation Factors

Effluent concentrations that are collected over time may be autocorrelated. The data are positively autocorrelated when measurements taken at specific time intervals, such as one or two days apart, are similar. For example, positive autocorrelation would occur if the effluent concentration were relatively high one day and were likely to remain high on the next and possibly succeeding days. Because the autocorrelated data affect the true variability of treatment performance, EPA typically adjusts the variance estimates for the autocorrelated data, when appropriate.

For this rulemaking, whenever there was sufficient data for a pollutant at a plant to evaluate the autocorrelation reliably, EPA estimated the autocorrelation and incorporated it into the calculation of the limitations. For a plant without enough data to reliably evaluate and obtain an estimate of the autocorrelation, EPA set the autocorrelation to zero in calculation of the limitations. EPA did so because there were not sufficient data to reliably evaluate the autocorrelation, nor did EPA have a valid correlation estimate available that could be transferred from a similar technology and wastestream. See the memorandum entitled, “Serial Correlations for Steam Electric With and Without Adjustment for Baseline Values” for details of the statistical methods and procedures EPA used to determine the autocorrelation values, as well as a detailed discussion of the minimum number of observations needed to obtain a reliable estimate of the autocorrelation [Westat, 2013]. The following paragraphs describe the instances where EPA was able to obtain an estimated autocorrelation and the assumptions made about the autocorrelation when there were too few observations to estimate the autocorrelation.

For the biological treatment technology for FGD wastewater (represented by Allen and Belews Creek plants), EPA was able to perform a statistical evaluation of the autocorrelation and obtain a reliable estimate of the autocorrelation because several years of data were available for these plants. As a result of the evaluation, EPA determined that adjustments for autocorrelation should be incorporated into the limitations for the biological treatment technology option. Table 13-2 below lists the autocorrelation values EPA used in the calculation of the limitations for nitrate-nitrite as N and selenium. No autocorrelation values are presented here for arsenic and mercury since EPA transferred the limitations from chemical precipitation technology option for FGD for these pollutants (see Section 13.7.2 for a detailed discussion of the transfer of these limitations).

Table 13-2. Summary of Autocorrelation Values Used in Calculating the Limitations for Biological Treatment Technology Option for FGD Wastewater

Pollutant	Correlation Value Used for Limit Calculations
Selenium	0.291
Nitrate-nitrite as N [a]	

a - There were only eight observations available for nitrate-nitrite as N (only EPA sampling and CWA 308 sampling data available) at Allen and Belews Creek, so EPA was not able to evaluate the autocorrelation. EPA transferred the autocorrelation from selenium since these two chemicals behave similarly in the biological treatment system.

For the chemical precipitation treatment option for FGD wastewater (represented by Hatfield’s Ferry, Keystone, and Miami Fort plants), for the vapor-compression evaporation treatment technology option for FGD wastewater (represented by Brindisi), and for the vapor-compression evaporation treatment technology option for gasification wastewater (represented by Polk and Wabash River), EPA was unable to perform an evaluation and obtain a reliable estimate of the autocorrelation because there were too few observations available at the plants. Thus, for these plants, EPA set the autocorrelation to zero in the calculation of the limits. EPA did so because there were not sufficient data to reliably evaluate the autocorrelation, nor did EPA have a valid correlation estimate available that could be transferred from a similar technology and wastestream.

13.7 Transfers of the Limitations

In some cases, EPA was either unable to calculate the limitations since there was no data available for the treatment technology option or determined that the treatment provided by plants employing the technology option did not fully represent the performance achievable by proper operation of all components of the model technologies. In these cases, EPA transferred limitations from another technology option. The following sections describe each case in which the limitations were transferred.

13.7.1 Transfer of Arsenic and Mercury Limitations from Chemical Precipitation to Leachate

The effluent limitations for leachate based on the chemical precipitation technology option are transferred from the chemical precipitation technology option for FGD wastewater because EPA does not have the available effluent data for leachate from the plants that employ the chemical precipitation technology. This transfer of limitations for arsenic and mercury is appropriate because the pollutants in leachate are similar to those in FGD wastewater except at lower concentrations. The use of chemical precipitation technology to remove arsenic and mercury has been extensively demonstrated for a wide variety of industrial wastewaters including leachate from other industrial landfills. Because of the similarities between leachate and FGD wastewater, plants employing chemical precipitation treatment technology for leachate wastewater should be able to comply with the proposed limitations.

13.7.2 Transfer of Arsenic and Mercury Limitations from Chemical Precipitation to Biological Treatment for FGD Wastewater

EPA is transferring the FGD wastewater effluent limitations for arsenic and mercury calculated for the chemical precipitation technology option to the biological treatment technology option. This transfer of limitations for arsenic and mercury is appropriate because the plants represented by the chemical precipitation technology option better reflect the effluent concentrations that would be attained by the biological technology when it employs all features in the technology option that work to remove arsenic, mercury and many other metals from the wastewater. The technology upon which biological treatment is based includes the following: equalization of the influent wastewater; chemical precipitation/coprecipitation to precipitate and remove both dissolved and particulate forms of the targeted pollutants (including pH adjustment, hydroxide precipitation, iron coprecipitation, sulfide precipitation, and clarification/filtration); and anoxic/anaerobic biological treatment to remove nitrogen (i.e., nitrate-nitrite as N) and both soluble and insoluble forms of selenium. All of these treatment steps contribute to the mercury removals achieved by the biological treatment technology although in different ways. Equalization of the treatment system influent stream acts to reduce the variability of the untreated wastewater, reducing extreme variations in flow rates and pollutant concentrations. In doing so, chemical dosage rates in chemical reaction tanks and clarifiers are more closely tuned to the characteristics of the untreated wastewater and provide the necessary chemistry adjustments. In addition, physical mixing or settling conditions are not subjected to sudden extreme fluctuations. The data for the biological treatment technology demonstrates that it is also effective at removing mercury from FGD wastewater, on the order of as much as 90 percent of the mercury entering the bioreactor.

EPA evaluated what the limitations for arsenic and mercury would be based on data from the two plants employing biological treatment: Allen and Belews Creek. Both of these plants have installed all equipment associated with the model technology; however, while both plants have installed the capability to add organosulfide chemicals to achieve sulfide precipitation of dissolved mercury in the chemical precipitation stage preceding the bioreactors, neither plant was dosing the organosulfide chemical during the periods covered by the effluent performance data. Although hydroxide precipitation may be sufficient for meeting NPDES permit limits for some plants, plants striving to maximize removals of mercury and other metals will also include sulfide addition (e.g., organosulfide) as part of the process. Adding sulfide chemicals in addition to the alkali provides even greater removals of heavy metals due to the very low solubility of metal sulfide compounds, relative to metal hydroxides. It is for this reason that the technology basis, for both the chemical precipitation technology option and the biological treatment technology option, includes the use of hydroxide precipitation, sulfide precipitation, and iron coprecipitation. Thus, although both Allen and Belews Creek have the technology in place, since neither was actually adding organosulfide they were not optimizing the pollutant removal efficacy of the treatment systems. Because of this, the treatment systems are susceptible to fluctuations in concentrations of dissolved metals, especially mercury, in the FGD wastewater. When the technology is operated without adding the chemicals for sulfide precipitation, it can be overwhelmed by high concentrations of dissolved mercury. To the extent these high concentrations of dissolved mercury pass though the chemical precipitation treatment stage (which is only partially effective at removing dissolved mercury when sulfide precipitation is not employed), they can also pass through the biological treatment stage at higher than normal concentrations even if approximately 90 percent of the mercury entering the bioreactors is removed. EPA's analysis of the performance data for Allen and Belews Creek shows that dissolved mercury is not being adequately treated at these plants, which is attributable to the plants not adding organosulfide. In contrast, the plants used as the basis for the chemical precipitation technology are all adding organosulfide chemicals and operating the other key components for the chemical treatment stage for the biological treatment technology. EPA determined that the data used for chemical precipitation limitations better reflect the treatment efficacy for mercury and arsenic (and many other metals for which limitations are not being established) for treatment systems employing chemical precipitation/coprecipitation with both hydroxide and sulfide precipitation.

As a result, EPA is proposing to establish the biological treatment technology limitations for arsenic and mercury based on transferring the limitations calculated for chemical precipitation treatment technology. EPA notes that it is reasonable to expect plants employing the biological treatment technology to actually achieve even better effluent performance, since the biological treatment stage will remove additional mercury following the chemical precipitation upon which the mercury and arsenic limits are now based.

13.8 SUMMARY OF THE LIMITATIONS

Section 13.8.1 provides a summary of the plant-specific long-term averages, plant-specific daily variability factors, and plant-specific monthly variability factors for each pollutant in each treatment technology option. Section 13.8.2 provides a summary of the proposed limitations together with the option long-term average and variability factors for each pollutant in each treatment technology option.

13.8.1 Summary of the Plant-Specific Long-Term Average and Variability Factors for Each Treatment Technology Option for FGD and Gasification Wastewaters

The plant-specific long-term average and variability factors for each pollutant for each treatment technology option for FGD and gasification wastewaters are presented below. The document entitled, "Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking" contains a listing of the data that were used to calculate the plant-specific results for each of the technology options [U.S. EPA, 2012c].

Chemical Precipitation Treatment Technology Option for FGD

Table 13-3 presents the plant-specific results (i.e., long-term averages and variability factors) for chemical precipitation as the technology basis for FGD wastewater. The pollutants proposed to be regulated under this technology option are arsenic and mercury.

Table 13-3. Plant-Specific Results for Chemical Precipitation as the Technology Basis for FGD Wastewater

Pollutant	Plant Name	Autocorrelation Value	Plant-Specific Long-Term Average	Plant-Specific Daily Variability Factor	Plant-Specific Monthly Variability Factor
Arsenic (ug/L)	Hatfield's Ferry	0	6.682	2.285	1.373
	Keystone	0	4.006 [a]	--[b]	--[b]
	Miami Fort	0	4.483	1.197	1.072
Mercury (ng/L)	Hatfield's Ferry	0	75.404	4.083	1.766
	Keystone	0	64.260	3.257	1.584
	Miami Fort	0	168.569	2.286	1.361

a - Long-term average is the arithmetic mean since there were too few detected observations.

b - Nearly all observations were non-detected, so variability factors could not be calculated.

Biological Treatment Technology Option for FGD

Table 13-4 presents the plant-specific results (i.e., long-term averages and variability factors) for biological treatment for nitrate-nitrite as N and selenium as the technology basis for FGD wastewater. The pollutants proposed to be regulated under this technology option are arsenic, mercury, nitrate-nitrite as N, and selenium. As explained in detailed in Section 13.7.2 above, EPA is transferring the limitations for arsenic and mercury from the chemical precipitation treatment technology for FGD wastewater, thus, the table does not present the results for arsenic and mercury.

Table 13-4. Plant-Specific Results for Biological Treatment as the Technology Basis for FGD Wastewater

Pollutant	Plant Name	Autocorrelation Factor	Plant-Specific Long-Term Average	Plant-Specific Daily Variability Factor	Plant-Specific Monthly Variability Factor
Arsenic (ug/L) [a]	--	--	--	--	--
Mercury (ng/L) [a]	--	--	--	--	--
Nitrate-nitrite as N (mg/L)	Allen	0.291	0.104 [b]	-- [c]	-- [c]
	Belews Creek	0.291	0.115	1.499	1.157
Selenium (ug/L)	Allen	0.291	5.551	1.627	1.192
	Belews Creek	0.291	9.359	2.663	1.450

a - Option LTA, option variability factors, and effluent limitations were transferred from chemical precipitation technology option for FGD wastewater.

b - Long-term average is the arithmetic mean since there were too few detected observations.

c - Nearly all observations were non-detected, so variability factors could not be calculated.

Vapor-Compression Evaporation Treatment Technology Option for FGD

EPA based the limitations for the vapor-compression evaporation technology option on the effluent data at Brindisi. The treatment system for the Brindisi power plant actually produces two effluent streams: (1) brine concentrator distillate; and (2) crystallizer condensate. Both of these streams are essentially the condensed steam from different stages of the evaporation process. At Brindisi, these streams are ultimately recombined in a distillate tank and then reused at the plant. However, it is possible that a plant may choose to reuse both streams, discharge both streams, or reuse one stream while discharging the other to surface water. The effluent quality for the brine concentrator distillate and the crystallizer condensate are not identical. EPA anticipates that plants employing this treatment technology will often combine the two effluent streams from the evaporator. EPA considered establishing a single set of effluent limitations based on the two effluent streams being combined prior to discharge or reuse; however, there is sufficient uncertainty about the flow rates for each of the streams that preclude establishing a combined limitation. EPA also considered establishing two sets of effluent limitations, with a separate set of limitations for each effluent stream. Although this approach is technically feasible, it would require plants to collect and analyze separate samples for each effluent stream. EPA does not believe that establishing limitations for both effluent streams is necessary to ensure the FGD wastewater is being treated to the effluent quality achievable by operation of the evaporation technology, and that establishing separate limitations for each wastestream is unnecessarily burdensome. EPA believes a single set of effluent limitations will be sufficient to ensure the level of control would be achieved, should vapor-compression evaporation be selected as the technology basis for FGD wastewater. Because the effluent quality of the two effluent streams is not identical, EPA would establish the limitations based on the stream with the higher pollutant concentrations: crystallizer condensate. Setting the limitations on the higher concentration stream is necessary to ensure plants operating a well-designed and well-operated evaporation system can meet the limitations, regardless of whether they sample the effluent streams separately or as a combined stream. See the memorandum entitled, "Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking for the limitations that were calculated for each of the effluent streams discussed above [U.S. EPA, 2012a].

Table 13-5 presents the plant-specific results (i.e., long-term averages and variability factors) for vapor-compression evaporation treatment as the technology basis for FGD wastewater. The pollutants proposed to be regulated under this technology option are arsenic, mercury, selenium, and total dissolved solids (TDS).

Table 13-5. Plant-Specific Results for Vapor-Compression Evaporation (Crystallizer Condensate) as the Technology Basis for FGD Wastewater

Pollutant	Plant Name	Autocorrelation Value	Plant -Specific Long-Term Average	Plant -Specific Daily Variability Factor	Plant - Specific Monthly Variability Factor
Arsenic (ug/L)	Brindisi	0	4.0 [a]	--[b]	--[b]
Mercury (ng/L)	Brindisi	0	17.788	2.192	1.338
Selenium (ug/L)	Brindisi	0	5.0 [a]	--[b]	--[b]
TDS (mg/L)	Brindisi	0	14.884	3.341	1.572

a - Long-term average is the arithmetic mean since all observations were detected observations.

b - All observations were non-detected, so variability factors could not be calculated.

Vapor-Compression Evaporation Treatment Technology Option for Gasification Wastewater

In developing the limitations for this technology option, EPA calculated the limitations using the data from Wabash River and Polk. The treatment system at Wabash River produces one effluent stream: condensate from vapor compression evaporator. The treatment system for Polk Power Station actually produces two effluent streams: (1) condensate from the vapor compression evaporator; and (2) condensate from the forced circulation evaporator. Both of these streams at Polk are essentially the condensed steam from different stages of the evaporation process. Because it is possible that a plant may choose to reuse both streams, discharge both streams, or reuse one stream while discharging the other to surface water. EPA considered data from the following effluent streams when developing the limitations for this technology option: (i) forced circulation evaporator condensate effluent (based only on Polk); and (ii) vapor compression evaporator effluent (based on Polk and Wabash River). EPA is proposing the limitations for this technology option based on vapor compression evaporator effluent data. EPA decided to propose the limitations based on vapor compression evaporator effluent data since EPA determined that the data collected at forced circulation evaporator condensate did not demonstrate typical removal rates for pollutants generally well treated by evaporation and therefore were not adequate to form the basis of the limitations. Based on its review of the treatment system, EPA believes that the evaporator (or at a minimum the forced circulation evaporation stage) was operating abnormally and allowing carryover of pollutant to the condensate effluent stream. For this reason, EPA based the limitations for this technology option on the limitations calculated from the vapor compression evaporator effluent data. Table 13-6 presents the plant-specific results (i.e., long-term averages and variability factors) for vapor-compression evaporation treatment as the technology basis for gasification wastewater. The pollutants proposed to be regulated under this technology option are arsenic, mercury, selenium, and total dissolved solids (TDS). As explained in Section 13.4, the data for arsenic and mercury at Wabash River failed the data editing criteria, thus, EPA excluded the arsenic and mercury datasets from Wabash River when calculating the limitations for this technology option.

Table 13-6. Plant-Specific Results for Vapor-Compression Evaporation (Vapor-Compression Evaporator Condensate) as the Technology Basis for Gasification Wastewater

Pollutant	Plant Name	Autocorrelation Factor	Plant -Specific Long-Term Average	Plant -Specific Daily Variability Factor	Plant - Specific Monthly Variability Factor
Arsenic (ug/L)	Polk	0	4.00 [a]	-- [b]	-- [b]
Mercury (ng/L)	Polk	0	1.075	1.632	1.194
Selenium (ug/L)	Polk	0	288.430	3.083	1.545
	Wabash River	0	5.130	-- [b]	-- [b]
TDS (mg/L)	Polk	0	16.512	2.149	1.327
	Wabash River	0	13.906	2.818	1.450

a - Long-term average is the arithmetic mean since there are too few detected observations.

b - Nearly all observations were non-detected, so variability factors could not be calculated.

13.8.2 Summary of the Option Long-Term Averages, Option Variability Factors, and Limitations for Each Treatment Technology Option for FGD, Gasification, and Leachate Wastewaters

This section presents the proposed daily maximum and monthly average limitations, as well as the option long-term average and variability factors for each pollutant in each of the treatment technology options for FGD, gasification, and leachate wastewaters. These results were obtained by combining the plant-specific results in each technology option presented in Section 13.8.1 (except for leachate wastewater because the limitations for leachate were transferred). As mentioned above, the option long-term average for each pollutant is the median of the plant-specific long-term averages. The option variability factor for each pollutant is the mean of the plant-specific variability factors. The daily limitation for each pollutant is the product of the option long-term average and option daily variability factor. The monthly average limitation for each pollutant is the product of the option long-term average and option monthly variability factor.

The limitations for FGD wastewater based on chemical precipitation followed by vapor-compression evaporation and the limitations for gasification wastewater based on vapor-compression are each based on data from one plant. As such, the option long-term averages and variability factors for these options are the same as the plant-specific long-term averages and variability factors. Also, in special cases where there are too few detected results, the statistical models are not appropriate for calculating limitations since reliable estimates could not be obtained from the models. In such instances, EPA has established the daily maximum limitations based on the detection limit (i.e., "minimum level").[112] Also, monthly average limitations are not established when the daily maximum limitation is based on the detection limit.

In developing the long-term average and variability factors, EPA used five digit decimal points for accuracy (but only three digit decimal points are presented in for simplification of the presentation); however, EPA rounded the limitations upward to allow for more variability during actual monitoring. In most instances, limitations greater than 1.0 were rounded upward to the next highest integer, while limitations less than 1.0 were rounded up to the next highest hundredths decimal place. For gasification wastewater, however, if EPA were to round both limitations up to the next highest integer, the daily and monthly average limitations for mercury for gasification wastewater would be the same (i.e., both limits would be 2 ng/L since the pre-rounded daily and monthly average limitations were calculated to be 1.754 and 1.284, respectively). Thus, in order to avoid having the same value for the daily and monthly average limitation, the proposed daily and monthly average limitations for mercury for gasification wastewater were rounded to next highest hundredths decimal place.

Table 13-7 provides the preferred option long-term average, option variability factors, and limitations for each of the FGD, gasification, and leachate technology options.

Table 13-7. Proposed Option Long-Term Averages, Option Variability Factors, and Limitations for Each of the FGD, Gasification, and Leachate Technology Options

Treatment Technology Option	Pollutant	Option Long-Term Average	Option Daily Variability Factor	Option Monthly Variability Factor	Daily Maximum Limitation[d]	Monthly Average Limitation[d]
Chemical Precipitation for FGD Wastewater	Arsenic (ug/L)	4.483	1.741	1.223	8	6
	Mercury (ng/L)	75.404	3.209	1.570	242	119
Chemical Precipitation and Biological Treatment for FGD Wastewater	Arsenic (ug/L) [a]	4.483	1.741	1.223	8	6
	Mercury (ng/L) [a]	75.404	3.209	1.570	242	119
	Nitrate-nitrite as N (mg/L)	0.110	1.499	1.157	0.17	0.13
	Selenium (ug/L)	7.455	2.145	1.321	16	10
Chemical Precipitation and Evaporation for FGD Wastewater	Arsenic (ug/L)	4.0 [b]	--[c]	--[c]	4 [e]	-- [f]
	Mercury (ng/L)	17.788	2.192	1.338	39	24
	Selenium (ug/L)	5.0 [b]	--[c]	--[c]	5 [e]	--[f]
	TDS (mg/L)	14.884	3.341	1.572	50	24

[112] As used in this chapter of this document, "detection limit" refers to the quantitation limit (QL) and not the method detection limit (MDL). Thus, effluent limitations in those instances would be established as a daily maximum limit at the quantitation limit.

Table 13-7. Proposed Option Long-Term Averages, Option Variability Factors, and Limitations for Each of the FGD, Gasification, and Leachate Technology Options

Treatment Technology Option	Pollutant	Option Long-Term Average	Option Daily Variability Factor	Option Monthly Variability Factor	Daily Maximum Limitation[d]	Monthly Average Limitation[d]
Vapor-Compression Evaporation for Gasification Wastewater	Arsenic (ug/L)	4.0 [b]	-- [c]	-- [c]	-- 4[e]	-- [f]
	Mercury (ng/L)	1.075	1.632	1.194	1.76	1.29
	Selenium (ug/L)	146.780	3.083	1.545	453	227
	TDS (mg/L)	15.209	2.483	1.389	38	22
Chemical Precipitation for Leachate Wastewater	Arsenic (ug/L)[a]	4.483	1.741	1.223	8	6
	Mercury (ng/L)[a]	75.404	3.209	1.570	242	119

a - Option LTA, option variability factors, and limitations were transferred from chemical precipitation technology option for FGD wastewater.

b - Long-term average is the arithmetic mean since all observations were non-detected.

c - All observations were non-detected, so variability factors could not be calculated.

d - Limitations less than 1.0 are rounded up to the next highest hundredths decimal place. Limitations greater than 1.0 have been rounded upward to the next highest integer, except for limitations for mercury based on the vapor-compression evaporation treatment technology option for gasification wastewater which have been rounded up to the next highest hundredths decimal place.

e - Limitation is set equal to the detection limit.

f - Monthly average limitations are not proposed when the daily maximum limitation is based on the detection limit.

13.9 ENGINEERING REVIEW OF THE LIMITATIONS

In conjunction with the statistical methods, EPA performed an engineering review to verify that the proposed limitations are reasonable based upon the design and expected operation of the control technologies. The following sections describe two types of comparisons that EPA performed. First, EPA compared the limitations to the effluent data used to develop the limitations. Second, EPA compared the limitations to the influent data. For the detailed results of these comparisons, see the memorandum entitled, "Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking" [U.S. EPA, 2012a].

13.9.1 Comparison of Limitations to Effluent Data Used As Basis for the Limitations

As part of its data evaluations, EPA compared the value of the limitations to the effluent values used to calculate the limitations. This type of comparison helps to evaluate how reasonable the proposed limitations may be from an engineering perspective. Since EPA is proposing both daily and monthly average limitations, EPA has performed two comparisons for each pollutant in each technology option. EPA first compared the daily limitations to the daily effluent values. Second, EPA compared the monthly average limitations to all the effluent daily values, and identified those months where at least one value within a month exceeded the monthly average limitations.

After thoroughly evaluating the results of the comparison between the limitations and the effluent values used to calculate the limitations for each treatment technology option for FGD and gasification wastewaters, EPA determined that the statistical distributional assumptions used to develop the limitations are appropriate for the data, and thus the limitations for each technology option are reasonable. (This conclusion is also true for the leachate limitations based on the chemical precipitation technology since the leachate limitations were transferred from the FGD wastewater technology option.) If a plant properly designs and operates its wastewater treatment system to achieve the option long-term average for the model technology (rather than targeting performance at the effluent limitations themselves), it will be able to comply with the limitations. The sections below discuss the results of the comparisons for each of the technology options. See the memorandum entitled, "Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking" for a listing of all daily effluent values that exceeded the daily and monthly average limitations for each pollutant in each treatment technology option [U.S. EPA, 2012a].

Chemical Precipitation Treatment Technology Option for FGD Wastewater

For the chemical precipitation treatment technology option for FGD wastewater, EPA is proposing limitations for arsenic and mercury. The limitations were calculated using data from three plants: Hatfield's Ferry, Keystone, and Miami Fort.

For both arsenic and mercury, there are some daily effluent concentration values that are above both the daily and monthly average limitations. After thoroughly examining the data, EPA determined that the concentration values that are above both the daily and monthly limitations for arsenic came from the plant with relatively higher effluent concentration values (i.e., with a higher long-term average than the other two plants). EPA observed that the same was true for the mercury concentration values that are above both the daily and monthly limitations calculated for the chemical precipitation technology option. Since the limitations are developed using the data from all three plants, it is reasonable to expect that the plant with relatively higher concentrations is more likely to have values above the daily and monthly limitations. As EPA explains below in this section, it is reasonable for this situation to arise in the datasets used to calculate the limitations and there are specific steps plants can take that enable them to improve treatment system performance so that effluent concentrations would be in compliance with the proposed limitations at all times.

EPA also identified an instance where two (of four) daily concentration values in a month are higher than the monthly limitation, and the resulting monthly average is equal to the monthly average limitation. Instances such as this (i.e., where one or more individual results are higher than the monthly limitation, but the average of all results in a month are equal to or below the monthly limitation) are normal and consistent with the way effluent limitations are calculated and implemented in NPDES permits. This is illustrated, in fact, by the selenium data for the biological treatment technology option, as described in the next section. EPA also identified some cases where only one sample was taken during a month and the resulting concentration value for that lone sample is above the average monthly limitation. In such cases, additional monitoring of the effluent (e.g., at weekly intervals) would likely result in a monthly average that would fall below the monthly limitation.

In addition, EPA identified one month where two (out of four) daily concentration values from the month are above the monthly average limitation, and the resulting monthly average for all four values is above the monthly limitation. Based on its engineering judgment developed over years of evaluating wastewater treatment processes for power plants and other industrial sectors, EPA determined that the combination of additional monitoring, closer operator attention, and optimizing treatment system performance to target the effluent concentrations at the technology option long-term average will result in lower effluent concentrations that would be in compliance with the proposed effluent limitations.

EPA noted that while these plants were selected as representing the “best available” technology, it does not mean that the plants have the systems fully optimized, especially since most of the plants do not have specific limits on the FGD wastewater for the pollutants of concern or because their existing limits are well above what the system is achieving. Specifically, none of these three plants have specific limits for arsenic. Also, only Keystone and Hatfield’s Ferry have NPDES permit limits on mercury; however, their current permit limits are more than 30 times higher than the proposed BAT effluent limitations. For this reason, these plants currently do not need to closely monitor the treatment system to confirm performance below their permit limitation. If these plants were required to meet the proposed limitations, EPA believes that these plants would be capable of meeting the limitations without significant expense. For example, EPA’s review of chemical precipitation systems for this industry noted that plants could benefit from using an in-house mercury analyzer to monitor the performance of the system on a daily basis. Mercury analyzers have been effectively used at a power plant to alert operators when mercury concentrations begin trending upward so that they may take steps to adjust treatment system performance and remain in compliance with their NPDES permit limits. Furthermore, some plants that rely solely on hydroxide precipitation could add sulfide precipitation to improve removals of arsenic and mercury. Organosulfide addition, particularly using long-chain organosulfide polymers, has been demonstrated to be particularly effective at improving mercury removals in chemical precipitation treatment systems. Finally, EPA has also evaluated the results of testing at a power plant that, although its FGD wastewater treatment system had been in operation for more than a year and was operating at a steady state condition, the plant significantly improved the pollutant removal performance merely by altering the dosage rates for the wastewater treatment chemical additives. As a result, EPA identified various approaches plants can use to improve their performance and achieve the limitations. EPA notes that its compliance cost estimates for the proposed rule includes costs for mercury analyzers, sulfide precipitation, and proper dosing of treatment system chemical additives.

Based on the results of the comparisons described above, EPA determined that the statistical distributional assumptions are appropriate for the effluent data and that the proposed limitations are reasonable.

Biological Treatment Technology Option for FGD Wastewater

For the biological treatment technology option for FGD wastewater, EPA is proposing limitations for arsenic, mercury, nitrate-nitrite as N, and selenium. For arsenic and mercury, EPA transferred the limitations from the chemical precipitation treatment system for FGD wastewater (as explained in Section 13.7.2 above). Because the limitations for arsenic and mercury were transferred and since this technology option includes chemical precipitation as a first step, the comparison described above for the chemical precipitation technology option is relevant for arsenic and mercury. Because of this, EPA expects that the plants employing this technology option would be able to comply with the proposed arsenic and mercury limitations. Furthermore, EPA's data demonstrate that the biological treatment stage provides pollutant removals for arsenic and mercury (and other pollutants of concern with similar removal mechanisms) in addition to the pollutant removals that occur in the chemical precipitation stage of the biological treatment technology option (see, for example, Section 10.4.1). Thus, plants employing and optimally operating all components of the biological treatment technology option (including adding organosulfide to achieve sulfide precipitation) should achieve pollutant removals for arsenic and mercury (and other pollutants with similar removal mechanisms) that are equal to or even greater than the removals based on chemical precipitation technology.

For nitrate-nitrite as N at Allen, all daily effluent concentration values are below both the daily and monthly limitations. For nitrate-nitrite as N at Belews Creek, all daily effluent values are below the daily limitation. However, there are two nitrate-nitrite as N daily effluent values in different months that are above the monthly limitation. In each case only one sample was collected during the month. As explained above for the chemical precipitation technology option and demonstrated in the following paragraph, additional effluent monitoring (e.g., at weekly intervals) would likely result in a monthly average that would fall below the monthly limitation.

For selenium at Allen, all daily effluent concentration values are below the daily limitation. Only one daily effluent value (out of two collected in the same month) for Allen is above the monthly limitation. However, after averaging these two observations, the average for the month is below the monthly limitation. All other daily concentration values for Allen, spanning the period from September 2009 through May 2011, are below the average monthly limitation.

For selenium at Belews Creek, there are some daily effluent observations that are above both the daily and monthly limitations. After thoroughly examining the data, EPA determined that the effluent concentration values at Belews Creek are relatively higher (i.e., with a higher long-term average) than the effluent concentration values at Allen. As discussed above, since the limitations are developed using the data from both plants, it is reasonable to expect that the plant with relatively higher concentrations is more likely to have values above the daily and monthly limitations. Furthermore, as EPA explained above there are steps plants can take to achieve better treatment system performance to ensure compliance with the effluent limitations. EPA identified instances in which some daily effluent values at Belews Creek are above the average monthly limitations. However, these are the only concentration values that were collected within each of those months. As described above, additional effluent monitoring (e.g., at weekly intervals) would likely result in a monthly average that would fall below the monthly limitation. EPA also identified four instances where some (or all) daily concentration values from a month are above the monthly limitation, but the daily values for other samples collected within the month are below the monthly limitation. In these instances, the average for all samples collected within the month is above the monthly limitation. Three of these four instances occur in the first three months of operation (August–October 2008) following the end of the initial commissioning period for the treatment system. The Belews Creek FGD wastewater treatment system was the first FGD bioreactor system operated by Duke Energy, and one of the first two systems to begin operating in the U.S. After evaluating all selenium data for the biological treatment technology option (nearly three years of data for Belews Creek and nearly two years for Allen, excluding the initial commissioning periods), EPA concluded that the selenium results for August-October 2008 reflect less than optimum performance of the treatment system due either to the inexperience of operators with this type of treatment system, or to continued variability associated with the initial commissioning of the treatment system, or a combination thereof.[113] Based on the results of this comparison for the biological treatment technology option based on Allen and Belews Creek, EPA determined that the statistical distributional assumptions are appropriate for the effluent data and that the proposed limits are reasonable.

Vapor-Compression Evaporator Treatment Technology Option for FGD Wastewater

For the chemical precipitation followed by vapor-compression evaporation treatment technology option for FGD wastewater, EPA developed limitations for arsenic, mercury, selenium, and TDS. The limitations were calculated using data from Brindisi plant. All daily effluent concentration values are below the daily and monthly limitations. After thoroughly reviewing the data, EPA determined that the statistical distributional assumptions are appropriate for the effluent data and that the proposed limitations are reasonable.

Vapor-Compression Evaporator Treatment Technology Option for Gasification Wastewater

For the vapor-compression evaporation treatment technology option for gasification wastewater, EPA is proposing limitations for arsenic, mercury, selenium, and TDS. The limitations were calculated using data from both the Polk and Wabash River plants, except for the arsenic and mercury limitations, which were based only on data from Polk (since data from Wabash River failed the LTA test).

For arsenic and mercury, daily concentration values are below both the daily and monthly limitations. For total dissolved solids, there is one (out of four collected in the same month) daily effluent concentration value at Polk above the monthly limitation. However, after averaging these four observations, the average for the month is below the monthly limitation.

For selenium at Polk, there is one daily effluent concentration value above the daily limitation. Also, there are two (out of four collected in the same month) daily effluent values above the monthly average limitation. After averaging these four observations, the average for the month is above the monthly limitation. After thoroughly examining the data, EPA determined that the effluent concentration values for selenium at Polk are relatively higher (i.e., with a higher long-term average) than the effluent concentration values at Wabash River. As discussed above, since the limitations are developed using the data from both plants, it is

[113] Note that although the Belews Creek selenium data (and other pollutants as well) from August-October 2008 may be influenced by the initial commissioning period for the treatment system, EPA used these data when calculating the proposed effluent limitations for the biological treatment technology option for FGD wastewater. EPA has used the August-October 2008 data because although EPA believes that, as a general rule, the initial commissioning period duration will be on the order of 3-4 months, and certainly no more than 6 months except in unique circumstances, EPA has not confirmed that the initial commissioning for Belews Creek was of such exceptional duration. Without the information to confirm the commissioning period was still in progress, EPA concluded that the sampling data should be used when calculating effluent limitations.

reasonable to expect that the plant with relatively higher concentrations is more likely to have values above the daily and monthly limitations. Additionally, as discussed above in Section 13.8.1, the data for the Polk treatment system indicates that the evaporator (or at a minimum the forced circulation evaporation stage) was operating abnormally and allowing carryover of pollutants to the condensate effluent stream. Based upon its review of the data, EPA concluded if the plant designed and operated its treatment system to achieve the option long-term average for the model technology, then the plant will be able to comply with the proposed limitation. Further, EPA notes that the Polk reuses all treatment gasification wastewater (i.e., condensate) in the gasification process and does not discharge any gasification wastewater. As such, the plant's treatment objective is to ensure the wastewater is of sufficient quality for reuse in the process rather than to comply with a NPDES permit limit. Thus, EPA concluded that the statistical distributional assumptions are appropriate for the effluent data and that the proposed limitations are reasonable.

13.9.2 <u>Comparison of Proposed Limitations to Influent Data</u>

In addition to comparing the proposed limitations to the data used to develop the limitations, EPA also compared the proposed limitations to the influent concentration values. This comparison helps evaluate whether the proposed limitations are set at a level that ensures that treatment of the wastewater would be necessary to meet the limitations and that the influent concentrations were generally well-controlled by the treatment system. In doing so, EPA confirms that treatment to remove the regulated pollutants will take place. See the memorandum entitled, "Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking" for a detailed listing of the summary statistics for the influent data for each pollutant in each treatment technology option [U.S. EPA, 2012a].

For all treatment technology options for both FGD and gasification wastewater, the minimum, average, and maximum influent concentration values were much higher than the long-term average and proposed limitations. Thus, EPA determined that plants would need to treat the wastewater to ensure compliance with the proposed limitations and that the proposed rule would result in removing the regulated pollutants and other pollutants of concern. Furthermore, in evaluating influent concentrations, EPA found that influent concentrations were generally well-controlled by the treatment plant for all plants with model technology. In general, the treatment systems adequately treated even the extreme influent values, and the high effluent values did not appear to be the result of high influent discharges.

13.10 REFERENCES

1. Computer Sciences Corporation (CSC). 2013. Results of the ICP/MS Collision Cell Method Detection Limit Studies in the Synthetic Flue Gas Desulfurization Matrix. (16 January). DCN SE03872.
2. U.S. EPA. 2012a. Memorandum to Ronald Jordan: Effluent Limitations for FGD Wastewater, Gasification Wastewater, and Combustion Residual Leachate for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Rulemaking. (20 October). DCN SE01999.

3. U.S. EPA. 2012b. Memorandum to Steam Electric Rulemaking Record: Assessment of Effluent Limitations and Standards with No Baseline Substitution for the Steam Electric Rulemaking. (18 November). DCN SE02000.
4. U.S. EPA. 2012c. Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking. (31 October). DCN SE02002.
5. Westat. 2013. Memorandum to Cuc Schroeder: Serial Correlations for Steam Electric With and Without Adjustment for Baseline Values. (15 April). DCN SE02001.
6. Results of the ICP/MS Collision Cell Method Detection Limit Studies in the Synthetic Flue Gas Desulfurization Matrix - DCN SE03872

SECTION 14
REGULATORY IMPLEMENTATION

This section provides guidance to permit writers and control authorities (e.g., publicly owned treatment works (POTWs)) in implementing the revisions to the steam electric effluent limitations guidelines and standards (ELGs).

14.1 IMPLEMENTATION OF THE LIMITATIONS AND STANDARDS

Effluent guidelines limitations and standards act as a primary mechanism to control the discharge of pollutants to waters of the United States. The BAT and NSPS limitations and standards in the proposed rule would be applied to steam electric wastewater discharges through incorporation into NPDES permits issued by the EPA or states under Section 402 of the Act. The PSES and PSNS standards are implemented through pretreatment programs under Section 307 of the Act.

The Agency has developed the limitations and standards for this proposed rule to control the discharge of pollutants from the steam electric power generating point source category. Once promulgated, those permits or control mechanisms issued after this rule's effective date would be required to incorporate the effluent limitations guidelines and standards, as applicable. Also, under section 510 of the CWA, states may require effluent limitations under state law as long as they are no less stringent than the requirements of this rule. Finally, in addition to requiring application of the technology-based effluent limitations guidelines and standards in this rule, section 301(b)(1)(C) of CWA requires the permitting authority to impose more stringent effluent limitations on discharges as necessary to meet applicable water quality standards.

14.1.1 <u>Timing</u>

For the reasons explained in Section 8.2, EPA proposes that certain limitations and standards based on any of the eight main regulatory options being proposed for existing direct and indirect dischargers do not apply until July 1, 2017 (approximately three years from the effective date of this rule). EPA finds this is appropriate for any proposed BAT and PSES for FGD wastewater, gasification wastewater, fly ash transport water, flue gas mercury control wastewater, bottom ash transport water, or combustion residual leachate where EPA is not proposing to establish BAT limitations that are equal to BPT limitations. For those plants and wastestreams where EPA is proposing to establish BAT equal to the current BPT effluent limitations, the revised BAT requirements would be applicable on the effective date of the final rule.

The proposed requirements for new direct and indirect dischargers (NSPS and PSNS) and the proposed requirements for existing sources where BAT is set equal to BPT would be applicable as of the effective date of the final rule.

14.1.2 <u>Applicability of NSPS/PSNS</u>

In 1982, EPA promulgated NSPS/PSNS for certain discharges from new units. Regardless of the outcome of the current rulemaking, those units that are currently subject to the

1982 NSPS/PSNS will continue to be subject to such standards. In addition, EPA is proposing to clarify in the text of the regulation that, assuming the Agency promulgates BAT/PSES requirements as part of the current rulemaking, units to which the 1982 NSPS/PSNS apply will also be subject to any newly promulgated BAT/PSES requirements because they will be existing sources with respect to such new requirements.

14.1.3 Legacy Wastes

For the reasons explained in Section 8.1.2, EPA is proposing that BAT and PSES requirements for existing sources based on any of the eight main regulatory options would apply to discharges of FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, combustion residual leachate, and gasification wastewater generated on or after the date established by the permitting authority that is as soon as possible after July 1, 2017.[114] Such wastewater generated prior to that date (i.e., "legacy" wastewater), in the case of direct dischargers, would remain subject to the existing BPT effluent limits. EPA is also considering establishing BAT effluent limitations for legacy wastewater (except gasification wastewater) that would be equal to the existing BPT effluent limits.

EPA also considered subjecting the legacy wastewater (except gasification wastewater) to the proposed BAT and PSES requirements. However, EPA found that these legacy wastewaters are typically transferred to surface impoundments that often commingle these legacy wastewaters and also contain other plant wastewaters, such as cooling water, coal pile runoff, and/or other low volume wastes. For each of the wastestreams for which EPA is proposing new BAT/PSES requirements, EPA does not have data to demonstrate that the technologies identified as representing BAT for newly generated wastewater from the various sources considered (e.g., FGD wastewater, fly ash transport wastewater) would also represent BAT for the legacy wastewaters. For example, for fly ash transport water, the technology basis identified for the proposed zero discharge requirement (i.e., conversion to dry ash handling) would eliminate generating new volumes of fly ash transport water but does not eliminate fly ash transport water that has already been generated and transferred to an impoundment prior to the conversion. EPA also evaluated whether other technologies would be available that might represent BAT for these legacy wastewaters. However, EPA determined these alternatives are either impracticable or insufficient data are available for establishing effluent limitations. For example, for a surface impoundment that receives both fly ash transport water and cooling tower blowdown, if the plant converts to a dry ash handling system, the surface impoundment would cease to receive additional fly ash transport water, but it would continue to receive the cooling tower blowdown. In this example, the surface impoundment would now contain a mixture of cooling tower blowdown and legacy fly ash transport water. As the plant continues to discharge from the impoundment, the concentration of pollutants in the impoundment that are associated with the legacy fly ash transport water would decrease over time but theoretically would never become zero (i.e., "zero discharge") because the remaining legacy wastewater is diluted over time but is never completely flushed from the impoundment. As pollutant concentrations associated with the legacy wastewater decrease over time, the treatability of the legacy wastewater remaining in the impoundment may be affected and, similarly, the resulting concentrations in the treated effluent may be affected. For this reason, EPA has found that the technologies considered for legacy

[114] Except where BAT is equivalent to BPT.

wastewater in surface impoundments are either impracticable or insufficient data are available for establishing effluent limitations.

The remainder of this subsection presents examples of how the proposed BAT effluent limitations and the existing BPT limitations should be applied to these wastewaters after the date established by the permitting authority that is as soon as possible after July 1 2017. Wastewater generated prior to the date established by the permitting authority is referred to as "legacy" wastewater and wastewater generated after the date established by the permitting authority is referred to as "newly generated" wastewater.

Figure 14-1 presents an example treatment scenario for a plant operating an impoundment receiving only FGD wastewater prior to the implementation of the ELGs. Under Regulatory Options 3 and 4a, the plant will need to meet the new BAT effluent limitations for the FGD wastewater, in which case, EPA envisions that the plant will have installed a tank-based treatment system to meet the limits. However, the plant has several options for the configuration of the treatment system in association with the existing impoundment, which are included in the post rule scenarios in Figure 14-1. Under post rule scenario A, the plant transfers the newly generated FGD wastewater to the tank-based system and discharges directly from the tank-based system to the receiving water. In this case, the plant would be required to demonstrate compliance with the new BAT and the existing BPT effluent limitations for the newly generated FGD wastewater at the effluent from the tank-based treatment system. Additionally, any legacy FGD wastewater that remains in the existing impoundment could still be discharged (e.g., after a rainfall event, when dewatering the impoundment for closure) and would only be subject to the existing BPT effluent limitations.[115]

Under post rule scenario B, the plant transfers the newly generated FGD wastewater to the tank-based system and then transfers the effluent from the system to the existing impoundment, containing legacy FGD wastewater, for additional polishing prior to discharge. As stated in the proposed rule, and described further in Section 14.1.4.3, EPA is proposing to require monitoring for compliance with the proposed BAT effluent limitations for newly generated FGD wastewater prior to use of the FGD wastewater in any other non-FGD plant process or commingling of the FGD wastewater with any water or other process wastewater, except for combustion residual leachate (including legacy leachate) or legacy FGD wastewater that is treated to achieve pollutant removals equivalent to or greater than achieved by the BAT technology that serves as the basis for the proposed effluent limitations. In this case, because the existing FGD wastewater impoundment does not achieve equivalent removals compared to the tank-based system, the plant would be required to demonstrate compliance with the new BAT limitations for the newly generated FGD wastewater at the effluent from the tank-based FGD wastewater treatment system, and compliance with the BPT requirements for the commingled new/legacy FGD wastewater at the point of discharge from the existing FGD wastewater impoundment.

Under post rule scenario C, the plant transfers the newly generated FGD wastewater to the existing FGD wastewater impoundment, containing legacy FGD wastewater. The

[115] All examples presented in this section focus on the implementation of the ELGs. All NPDES discharge outfalls may also be required to comply with additional water quality-based effluent limitations.

impoundment effluent is then transferred to the tank-based treatment system. In this case, both the newly generated FGD wastewater and the legacy FGD wastewater would be treated by the tank-based FGD wastewater treatment system . In this case, the plant would be required to demonstrate compliance with the new BAT and existing BPT effluent limitations for FGD wastewater at the effluent from the tank-based treatment system (i.e., prior to discharge or commingling with other wastestreams).

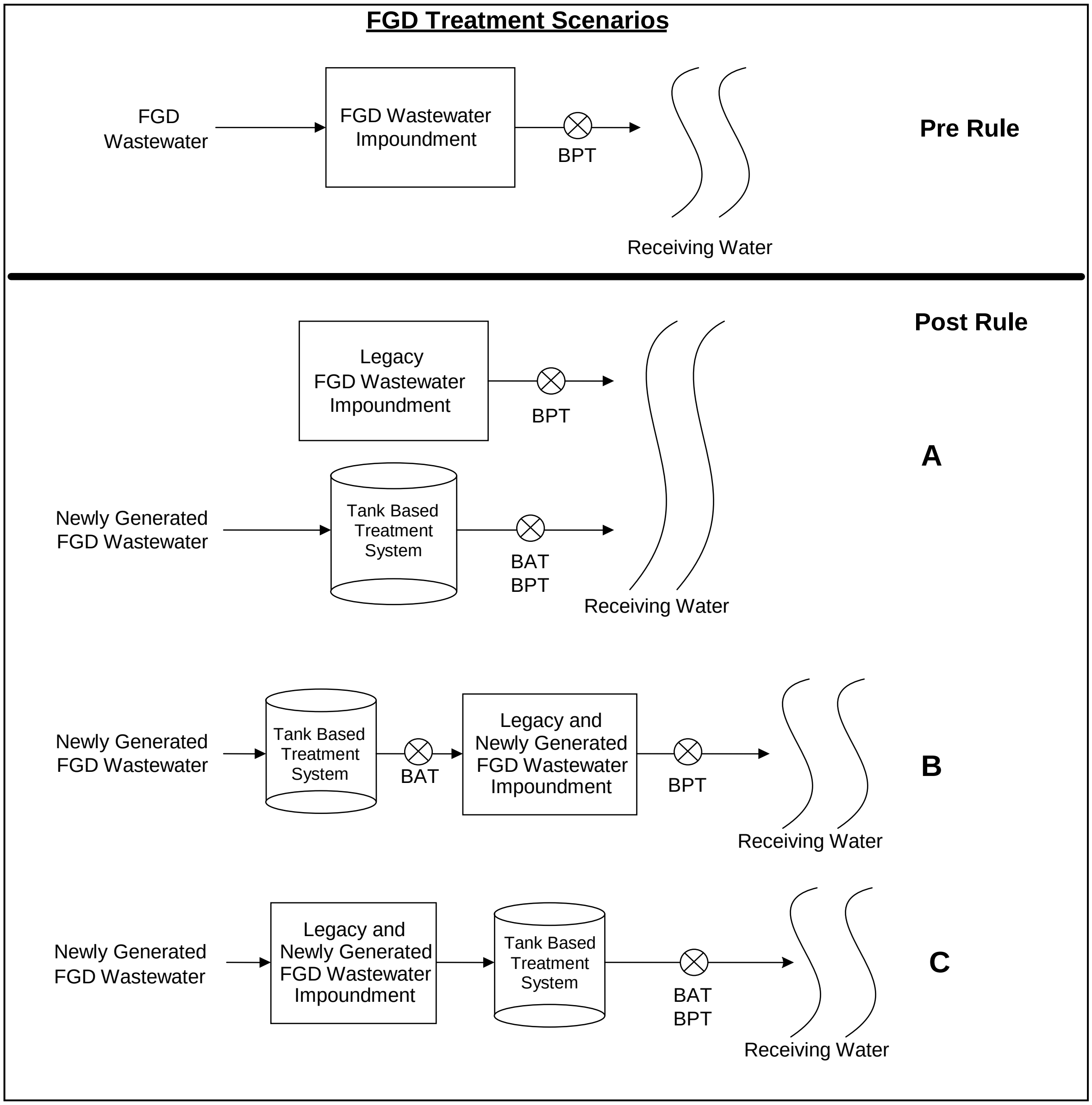


Figure 14-1. Legacy FGD Wastewater Treatment Scenario (Regulatory Options 3 and 4a)

Figure 14-2 presents an example treatment scenario for an impoundment receiving only fly ash transport water prior to the implementation of the ELGs. Under Regulatory Options 3a, 3b, 3, and 4a, the plant will need to meet the zero discharge BAT standard for fly ash transport water, in which case, EPA envisions that the plant will have installed a dry fly ash handling system to meet the new BAT limitation. In this case, the plant will no longer be transferring fly ash transport water to the impoundment. However, legacy fly ash transport water could still be discharged from the impoundment (e.g., after a rainfall event, when dewatering the impoundment for closure) and would only be subject to the existing BPT effluent limitations.

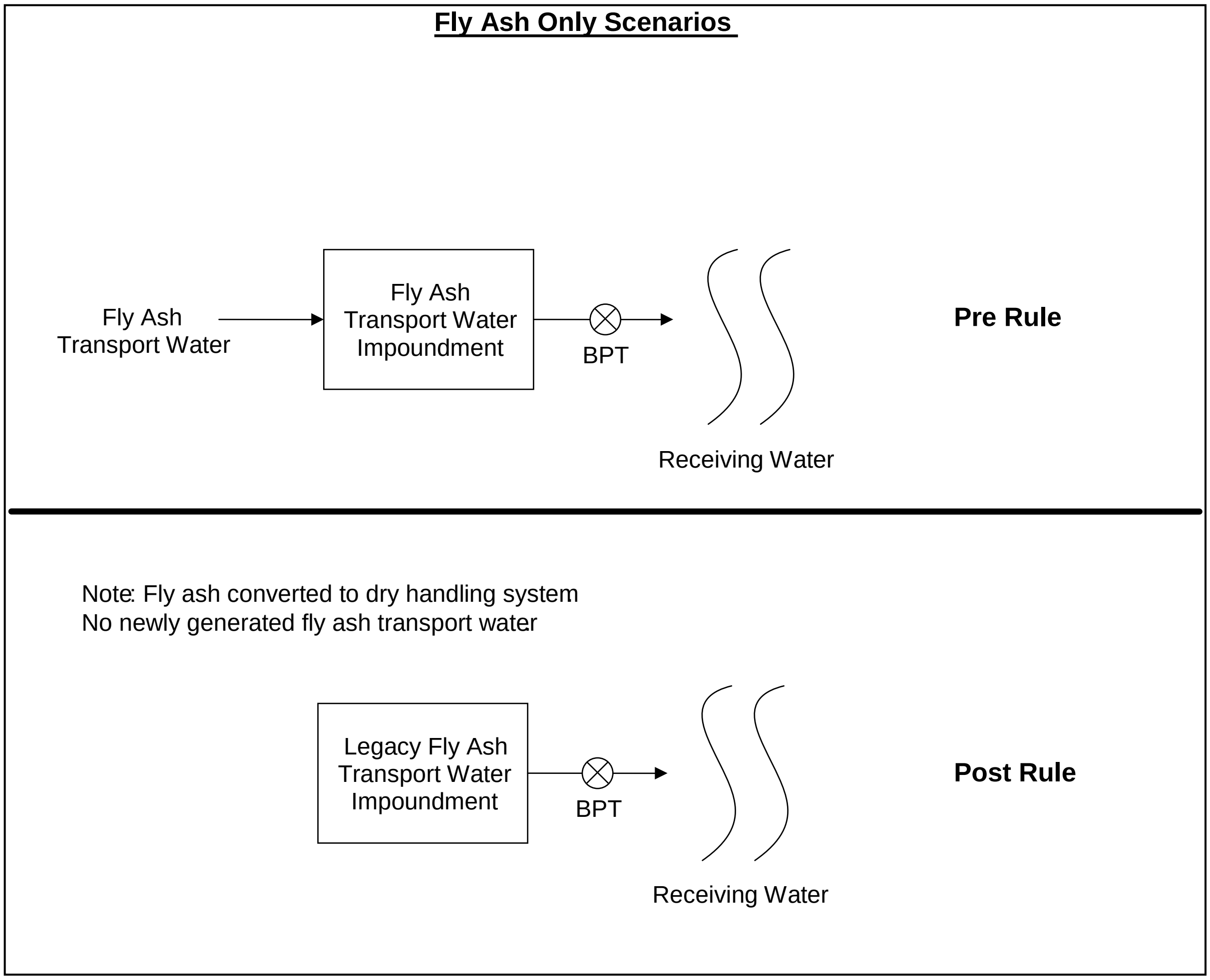


Figure 14-2. Legacy Fly Ash Transport Water Treatment Scenario (Regulatory Options 3a, 3b, 3, and 4a)

Figure 14-3 presents an example of the treatment scenario for a plant that operates a complete recycle fly ash sluicing system in which the plant does not discharge any fly ash transport water to a receiving water. Because the plant does not discharge fly ash transport water prior to the implementation of the rule, the plant can continue to operate using the same system (i.e., no system modifications required) and still be in compliance with the new zero discharge BAT limitation.

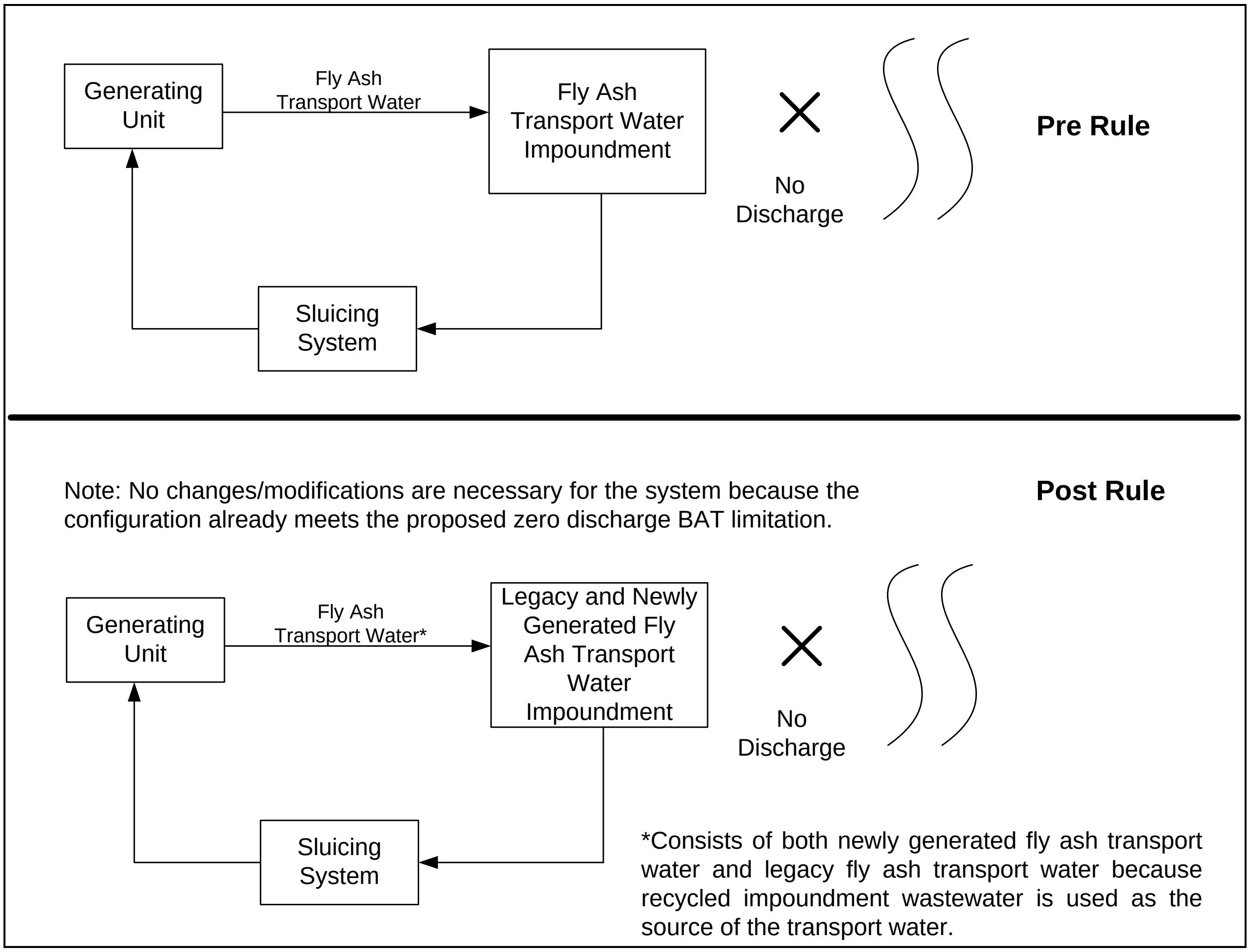


Figure 14-3. Complete Recycle Fly Ash Transport Water Treatment Scenario (Regulatory Options 3a, 3b, 3, and 4a)

Figure 14-4 presents an example treatment scenario for a plant that operates a partial recycle bottom ash sluicing system in which the plant recycles a majority of the bottom ash transport water for reuse in the system, but some of the bottom ash transport water is discharged to a receiving water. Under Regulatory Options 3a, 3b, and 3, the plant could continue to operate the system without any changes/modifications because Options 3a, 3b, and 3 would establish BAT limitations for bottom ash transport water equal to the current BPT limitations. However, under Regulatory Option 4, the plant will need to meet the new zero discharge BAT limitation, in which case, EPA envisions that the plant has two options for complying with the new limitation, which are included in the post rule scenarios in Figure 14-4. Under post rule scenario A, the plant would convert to a dry bottom ash handling system, and would not transfer any newly generated bottom ash transport water to the existing impoundment. However, legacy bottom ash transport water could still be discharged from the impoundment (e.g., after a rainfall event, when dewatering the impoundment for closure) and would only be subject to the existing BPT effluent limitations.

Under post rule scenario B, the plant would evaluate the water balance for the bottom ash system and determine whether the system could operate without discharging to a receiving stream. If the plant determines that the system can achieve complete recycle, then the plant can continue to operate the existing bottom ash handling system, but can no longer discharge the wastewater from the impoundment to the receiving water in order to meet the new zero discharge BAT limitation.

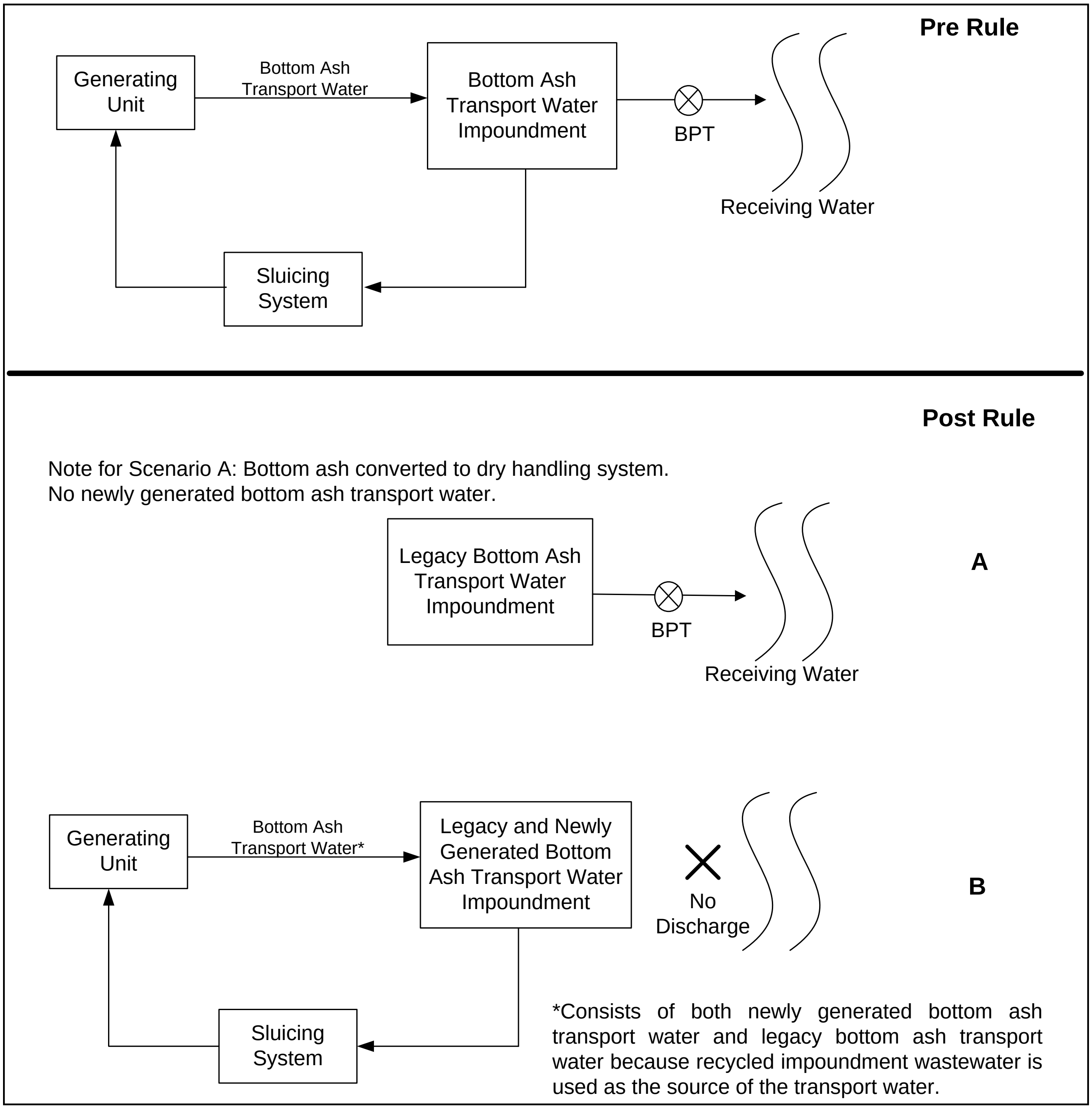


Figure 14-4. Partial Recycle Bottom Ash Transport Water Treatment Scenario (Regulatory Option 4)

Figure 14-5 and Figure 14-6 present example treatment scenarios for an impoundment receiving both fly ash and bottom ash transport water prior to the implementation of the ELGs. Figure 14-5 presents the treatment scenario under Regulatory Options 3a, 3b, and 3 and Figure

14-6 presents the treatment scenario under Regulatory Option 4. Under Regulatory Options 3a, 3b, and 3, the plant will need to meet the zero discharge BAT limitation for fly ash transport water, in which case, EPA envisions that the plant will have installed a dry fly ash handling system to meet the limitation. In this case, the plant will no longer be transferring fly ash transport water to the impoundment. However, the impoundment still contains legacy fly ash transport water and legacy bottom ash transport water and the impoundment will continue to discharge because of the newly generated bottom ash transport water that will continue to be transferred to the impoundment. In this case, the plant would be required to demonstrate compliance with the existing BPT effluent limitations for the legacy fly ash transport water and legacy bottom ash transport water and the new BAT effluent limitations for the newly generated bottom ash transport water.

Under Regulatory Option 4, the plant will need to meet the zero discharge BAT limitation for both fly ash transport water and bottom ash transport water, in which case, EPA envisions that the plant has two options for complying with the BAT limitations, which are included in the post rule scenarios in Figure 14-6. Under post rule scenario A, the plant would convert to a dry fly ash handling system and a dry bottom ash handling system, and would not transfer any newly generated fly ash transport water or newly generated bottom ash transport water to the existing impoundment. However, legacy fly ash transport water and legacy bottom ash transport water could still be discharged from the impoundment (e.g., after a rainfall event, when dewatering the impoundment for closure) and would only be subject to the existing BPT effluent limitations.

Under post rule scenario B, the plant would evaluate the water balance for the fly ash and bottom ash systems and determine whether the systems could operate without discharging to a receiving stream. If the plant determines that the systems can achieve complete recycle, then the plant can continue to operate the existing wet fly ash and bottom ash handling systems, but can no longer discharge the wastewater from the impoundment to the receiving water in order to meet the new zero discharge BAT limitations.

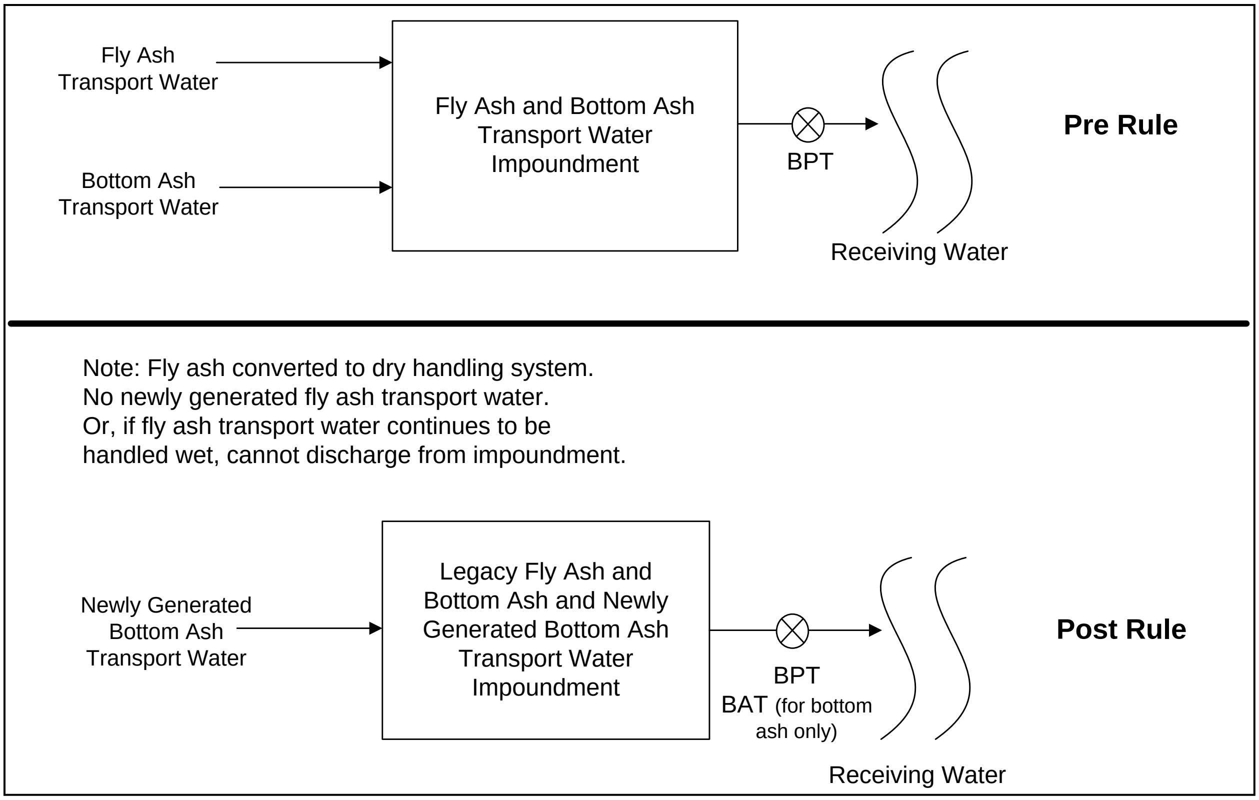


Figure 14-5. Legacy Fly Ash Transport Water Combined with Bottom Ash Transport Water Treatment Scenario (Regulatory Options 3a, 3b, and 3)

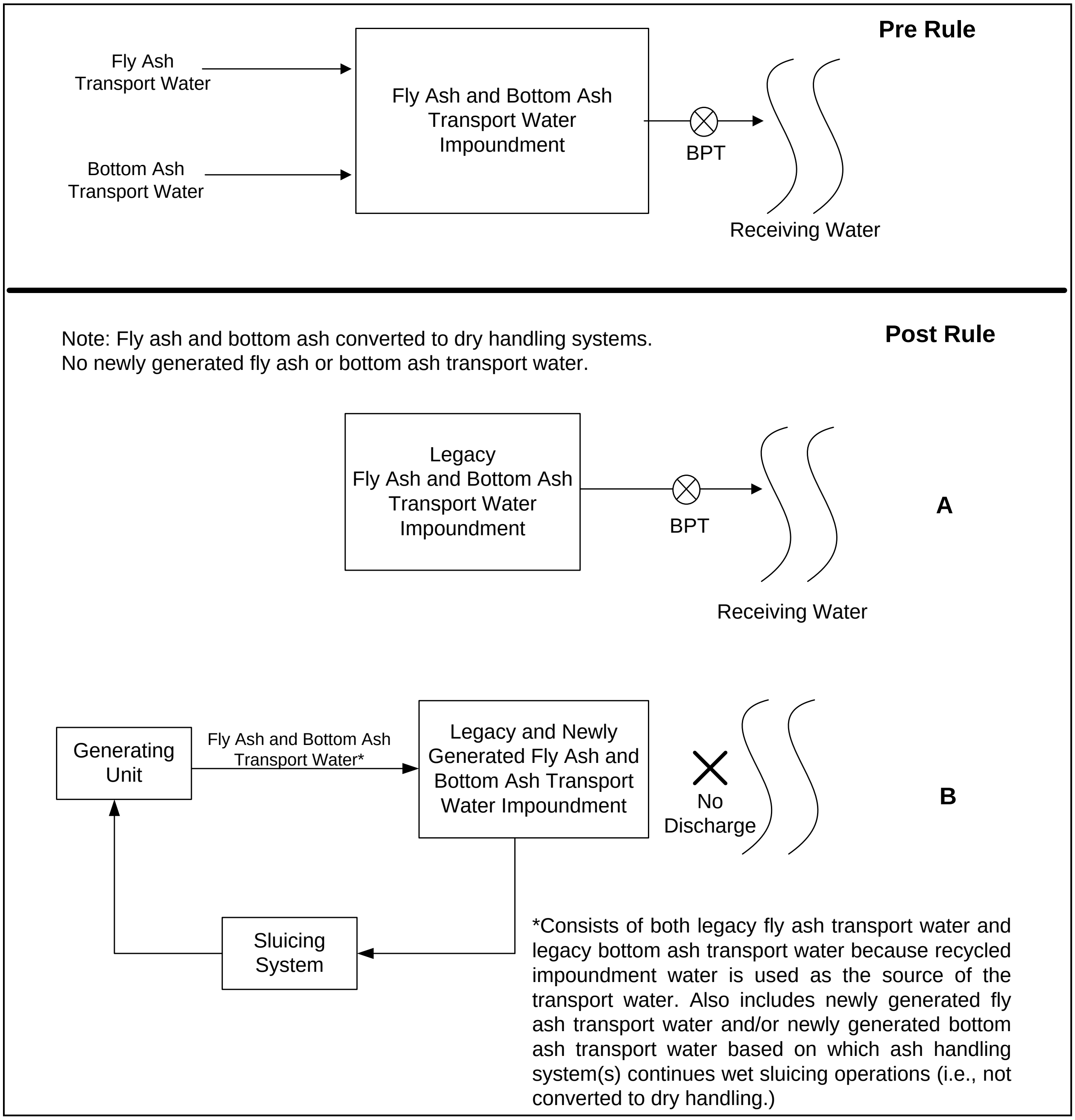


Figure 14-6. Legacy Fly Ash Transport Water Combined with Bottom Ash Transport Water Treatment Scenario (Regulatory Option 4)

Figure 14-7 and Figure 14-8 present example treatment scenarios for a system where FGD wastewater is treated in an impoundment receiving only FGD wastewater with the effluent from the impoundment being transferred to an impoundment that receives both fly ash and bottom ash transport water prior to the implementation of the ELGs. Figure 14-7 presents the treatment scenario under Regulatory Option 3 and Figure 14-8 presents the treatment scenario under Regulatory Option 4. Under Regulatory Option 3, the plant will need to meet the new BAT effluent limitations for FGD wastewater, in which case, EPA envisions that the plant will have installed a tank-based treatment system to meet the limitations. Additionally, the plant will need to meet the zero discharge BAT limitation for fly ash transport water, in which case, EPA envisions that the plant will have installed a dry fly ash handling system to meet the limitations. The plant has a couple options for the handling of the FGD wastewater in association with the existing impoundments, which are included in the post rule scenarios in Figure 14-7. Under the post rule scenario, the plant can either transfer the FGD wastewater from the tank-based system to the existing FGD impoundment, or the plant can bypass the FGD impoundment and transfer the effluent from the tank-based FGD wastewater treatment system directly to the existing ash impoundment. In either case, the plant would be required to demonstrate compliance with the new FGD wastewater BAT limitations at the effluent from the tank-based system, prior to entering either of the impoundments. The plant would also be required to demonstrate compliance with the existing BPT limitations for legacy and newly generated FGD wastewater, legacy fly ash transport water, and legacy bottom ash transport water, as well as the BAT limitation for newly generated bottom ash transport water, at the effluent from the ash impoundment.

Under Regulatory Option 4, the plant will need to meet the new BAT effluent limitations for FGD wastewater and the zero discharge BAT limitations for fly ash transport water and bottom ash transport water. In this case, EPA envisions that the plant will have installed a tank-based treatment system to treat the FGD wastewater and dry fly ash and dry bottom ash handling systems. As described for Regulatory Option 3, the plant has a couple options for the handling of the FGD wastewater, which are included in the post rule scenarios in Figure 14-8. Under the post rule scenario, the plant can either transfer the FGD wastewater from the tank-based system to the existing FGD impoundment, or the plant can bypass the FGD impoundment and transfer the effluent from the tank-based FGD wastewater treatment system directly to the existing ash impoundment. In either case, the plant would be required to demonstrate compliance with the new FGD wastewater BAT limitations at the effluent from the tank-based system, prior to entering either of the impoundment. The plant would also be required to demonstrate compliance with the existing BPT limitations for legacy and newly generated FGD wastewater, legacy fly ash transport water, and legacy bottom ash transport water at the effluent from the ash impoundment. The plant would not be able to discharge wastewater from the impoundments if newly generated fly ash transport water or bottom ash transport water was sent to the impoundment.

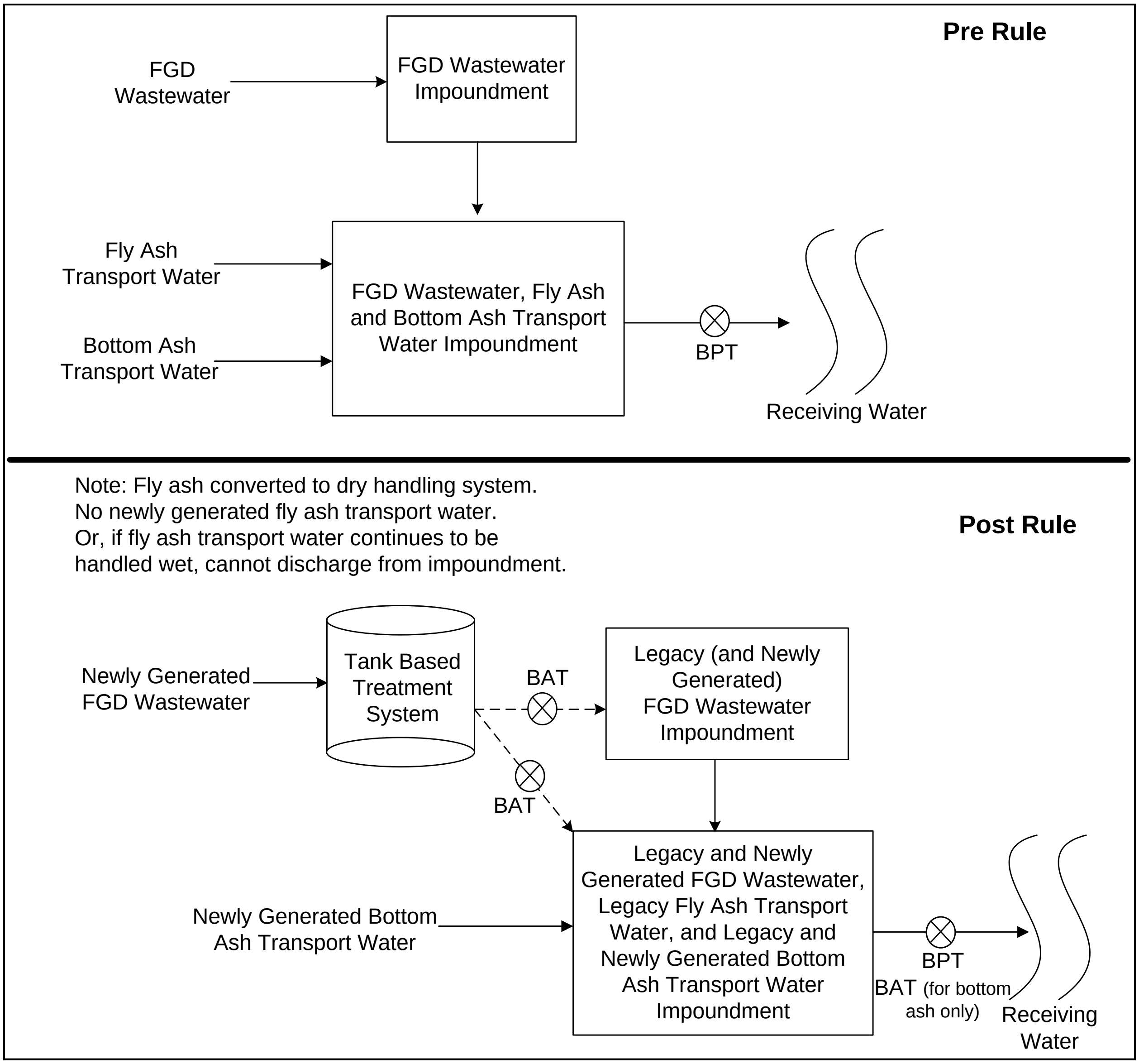


Figure 14-7. Legacy FGD Wastewater and Fly Ash Transport Water Combined with Bottom Ash Transport Water Treatment Scenario (Regulatory Option 3)

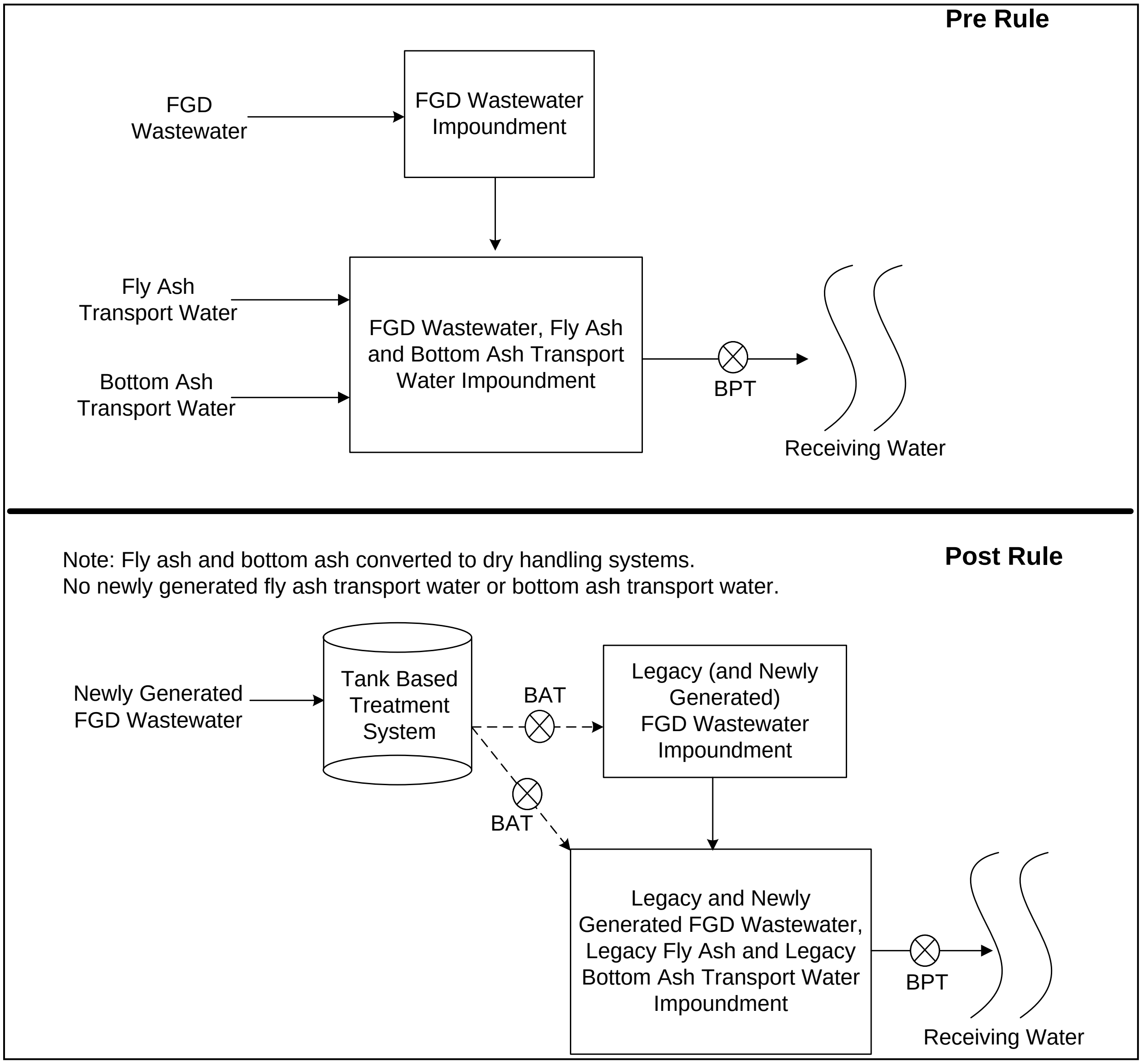


Figure 14-8. Legacy FGD Wastewater and Fly Ash Transport Water Combined with Bottom Ash Transport Water Treatment Scenario (Regulatory Option 4)

14.1.4 Monitoring Requirements

The NPDES permit regulations at §122.41(j)(4) and the pretreatment regulations at §403.12(b)(5)(vi) require that facilities conduct sampling and analyses to monitor compliance according to the techniques set out at 40 CFR 136, as amended. The Agency is proposing several specific monitoring requirements in the steam electric proposed rule. Sections 14.1.4.1 through 14.1.4.4 provide guidance on establishing these requirements.

14.1.4.1 Sample Types

EPA recommends flow-proportioned, 24-hour composite samples for the following regulated pollutants:

- Total dissolved solids;
- Total arsenic;
- Total selenium; and
- Nitrate/nitrite as N.

Part 136 recommends that plants use the clean sampling techniques described in EPA's draft method 1669: *Sampling Ambient Water for Trace Metals at EPA Water Quality Criteria Levels* (EPA-821-R-96-011) for mercury collection for EPA Methods 245.7 and 1631E to prevent contamination at low-level, trace metal determinations.[116] EPA Methods 245.7 and 1631E are the only Part 136-approved methods that have a detection limit low enough to be used for the mercury analysis for the FGD wastewater limit in the proposed rule. While EPA Methods 245.7, 1631E, and 1669 do not specifically require plants to collect mercury samples as grab samples, EPA recommends that mercury be collected as grab samples because there is less potential for contamination compared to composite sampling. EPA also recommends that mercury samples be collected as four grab samples in a 24-hour monitoring day, and that the results should be averaged to represent a daily sample.

14.1.4.2 Monitoring Frequency

The monitoring frequencies specified in steam electric NPDES permits vary depending upon the size of the plant, potential impacts on receiving waters, compliance history, and other factors, including monitoring policies or regulations required by permit authorities. The Agency is not proposing any specific monitoring frequencies; therefore, permit authorities may establish monitoring frequencies at their discretion, consistent with the requirements in 40 CFR 122.

When developing the proposed rule, EPA assumed a monitoring frequency of once per week for regulated pollutants. Facilities may monitor effluent more frequently than specified in their permits. During site visits, EPA observed that many plants often collect samples for key pollutants on a more frequent basis than required in their permits to help them stay attuned to treatment system performance and facilitate improved performance.

14.1.4.3 Compliance Monitoring Locations

Working in conjunction with the effluent limitations guidelines and standards are the monitoring conditions set out in a NPDES discharge permit or POTW control mechanism. An integral part of the monitoring conditions is the monitoring point. The point at which a sample is collected can have a dramatic effect on the monitoring results for that plant. Therefore, it may be

[116] EPA also recommends that plants use the clean sampling techniques for the collection of arsenic and selenium. If clean sampling techniques are not used, EPA recommends that field blanks be collected to evaluate whether contamination may be affecting the sampling results.

necessary to require internal monitoring points in order to assure compliance. Authority to address internal wastestreams is provided in 40 CFR 122.44(i)(1)(iii) and 122.45(h).

EPA is proposing that dischargers demonstrate compliance with the new effluent limitations and standards applicable to a particular wastestream prior to mixing the treated wastestream with other wastestreams, as described below. Therefore, with the exception of the cases where BAT limitations are equivalent to BPT limitations, any final limitations or standards (except pH) based on any of the eight main regulatory options in the proposed rule could require internal monitoring points. The following provides more detailed information for each wastestream:

- *FGD Wastewater*: Where an option proposes BAT/NSPS limitations for FGD wastewater that are not equal to existing BPT limitations, EPA is also proposing to require monitoring for compliance with the proposed effluent limitations and standards prior to use of the FGD wastewater in any other non-FGD plant process or commingling of the FGD wastewater with any water or other process wastewater.[117] This monitoring requirement would not, however, apply prior to commingling of FGD wastewater with combustion residual leachate (including legacy leachate) or legacy FGD wastewater that is treated to achieve pollutant removals equivalent to or greater than achieved by the BAT/NSPS technology that serves as the basis for the effluent limitations and standards in the proposed rule.

  For example, many plants currently treat their FGD wastewater and leachate in onsite surface impoundments. EPA envisions that, under the Option 3 requirements, some of these plants may choose to install tank-based FGD wastewater treatment systems for their newly generated FGD wastewater. Such a plant may choose to discharge the effluent from its new treatment system directly or may wish to discharge it to the existing surface impoundment containing legacy wastewaters. In this case, the plant would be required to demonstrate compliance with the proposed effluent limitations and standards for the newly generated FGD wastewater at the effluent from the tank-based FGD wastewater treatment system, and compliance with the BPT requirements for the commingled new/legacy FGD wastewater at the point of discharge from the FGD wastewater impoundment. The same plant may also configure its system so that the impoundment (which also contains legacy FGD wastewater) is used for equalization, with the impoundment effluent sent to the tank-based treatment system. In this case, both the newly generated FGD wastewater and the legacy FGD wastewater would be treated by the tank-based treatment system and an appropriate compliance monitoring point would be the treatment system effluent. Under such a scenario, commingling of FGD wastewater generated at any date may occur as long as such combined wastewater meets the effluent limitations or standards prior to use of the treated commingled new/legacy FGD wastewater in any other plant process, or combining the FGD wastewater with any water or other process wastewater. See Figure 14-1 for illustrations of these examples of the compliance monitoring points.

[117] Similarly applies to PSES and PSNS.

- *Ash Transport Water and FGMC Wastewater*: EPA is proposing to specify that whenever ash transport water or flue gas mercury control wastewater generated from a generating unit that must comply with the "zero discharge" standard is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the proposed discharge prohibition for the pollutants in such wastewater.

  For example, many plants currently treat their fly ash transport water in an onsite fly ash impoundment. In this case, under any proposed "no discharge" requirements, EPA envisions that such plants may convert their fly ash handling to a dry system, and no longer generate fly ash transport water. In such cases, the plant could demonstrate compliance with the proposed zero discharge requirement by showing that no fly ash transport water is generated after the date on which the new, proposed standards apply and by monitoring for compliance with the BPT requirements at the discharge from the legacy fly ash impoundment. See Figure 14-2 for an illustration of the example compliance monitoring points. Under EPA's proposal, the plant could not demonstrate compliance with the applicable discharge prohibition by simply using the fly ash transport water or FGMC wastewater in another plant process that ultimately discharges because the prohibition on the discharge of pollutants in ash transport water and FGMC wastewater is also applicable to the discharge of wastewater from plant processes that use these wastewaters.

- *Gasification Wastewater*: EPA is proposing to require monitoring for compliance prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with water or any other process wastewater. For example, EPA envisions gasification plants would show compliance with the proposed BAT or PSES requirements directly following gasification wastewater treatment (however, there would be no need to demonstrate compliance if the gasification wastewater is completely reused within the gasification process).
- *Combustion Residual Leachate*: Under Options 4 and 5, EPA is proposing to require monitoring for compliance prior to use of leachate in any other plant process or commingling of the leachate with water or any other process wastewater. This monitoring requirement would not, however, apply prior to commingling of combustion residual leachate with FGD wastewater (including legacy FGD wastewater) or legacy combustion residual leachate that is treated to achieve pollutant removals equivalent to or greater than that achieved by the BAT/NSPS technology that serves as the basis for the effluent limitations and standards in the proposed rule.

  For example, many plants currently treat their leachate in onsite surface impoundments. EPA envisions that some plants may choose to install a tank-based leachate treatment system so that the impoundment (which also contains legacy combustion residual leachate) is used for equalization, with the impoundment effluent ultimately sent to the tank-based treatment system. In this case, both the newly generated leachate and the legacy leachate would be treated by the tank-based treatment system and an appropriate compliance monitoring point would be the treatment system effluent. Under such a scenario, commingling of combustion residual leachate generated at any date may occur as long as such combined wastewater meets the effluent limitations or standards prior to use of the treated commingled new/legacy leachate in any other plant process, or combining the leachate with any water or other process wastewater. (If the combustion residual leachate is commingled with FGD wastewater, the plant will also have to demonstrate compliance with the applicable FGD wastewater effluent limitations and standards.)

14.1.4.4 Size Threshold Implementation

Under the BAT/PSES regulatory options, EPA is proposing to set size thresholds which would subject discharges from certain generating units to a different set of controls. The following provides examples of how these size thresholds should be evaluated for the purposes of setting permit requirements.

Fly Ash 50 MW Threshold (Options 3a, 3b, 3, 4a, 4, 5)

Under the proposed regulatory options, there is the potential that some generating units at a plant would need to comply with the proposed "zero discharge" requirement, while other units at the plant would only need to comply with the current BPT standards. For example, consider a plant that has a generating unit with a nameplate capacity of 50 MW or less and another generating unit with a nameplate capacity of greater than 50 MW that both discharge fly ash transport water. In this case, if the plant continues to wet sluice the fly ash from the unit with a nameplate capacity greater than 50 MW, the fly ash transport water for that unit must be completely reused in a process that does not ultimately discharge to surface waters, including indirect discharges to POTWs, (or the unit converted to dry handling) to be in compliance with the proposed "zero discharge" requirement. The fly ash transport water from the unit with a nameplate capacity greater than 50 MW cannot be reused to wet sluice the fly ash for the generating unit with a nameplate capacity of 50 MW or less if it is ultimately discharged. Therefore, the plant has three potential options to comply with the proposed "zero discharge" requirement for the generating unit with a nameplate capacity of greater than 50 MW:

- Convert the generating unit to dry fly ash handling;
- Commingle the fly ash transport water for all generating units and completely recycle the fly ash transport water with no discharge from any of the generating units; or
- Segregate the fly ash transport water for the generating unit with a nameplate capacity greater than 50 MW and completely recycle that within that specific unit, but still discharge the fly ash transport water from the generating unit with a nameplate capacity of 50 MW or less.

This example would also apply to the 400 MW threshold for bottom ash transport water under Option 4a.

FGD Wastewater 2,000 MW Plant-Level Wet-Scrubbed Capacity Threshold (Option 3b)

EPA is not proposing to establish BAT/PSES for discharges of FGD wastewater under Option 3b, for those plants that have a total plant-level wet scrubbed capacity of less than 2,000 MW. Therefore, if a plant has a total wet scrubbed capacity of 1,800 MW, no new effluent limits would be established under BAT or PSES for discharges of FGD wastewater. However, if the plant were to install a new wet FGD system with a nameplate capacity of 200 MW or greater at a later time, which would put the plant at or above the 2,000 MW threshold, the plant would then be required to comply with the proposed effluent limits for all FGD wastewater generated at the plant, not just the wastewater associated with the new FGD system. Therefore, at the time the plant begins operation of the new FGD system, the plant would be required to meet the proposed arsenic, mercury, selenium, and nitrate-nitrite limitations for all FGD wastewater discharges at the plant.

14.2 ANALYTICAL METHODS

Section 304(h) of the CWA directs the EPA to promulgate guidelines establishing test procedures (methods) for the analysis of pollutants. These methods are used to determine the presence and concentration of pollutants in wastewater and for compliance monitoring. They are also used for filing applications for the National Pollutant Discharge Elimination System (NPDES) permit program under 40 CFR 122.41(j)(4) and 122.21(g)(7), and under 40 CFR 403.7(d) for the pretreatment program. The EPA has promulgated analytical methods for monitoring discharges to surface water at 40 CFR part 136 for the pollutants proposed for regulation in the proposed rule. As part of this proposed rule, EPA is providing notice of standard operating procedures (SOPs) for the analysis of FGD wastewater using collision cell technology in conjunction with EPA Method 200.8. EPA Method 200.8 has been promulgated under 40 CFR part 136 and is an approved method for use in NPDES compliance monitoring. Also, the use of collision cell technology is an approved modification allowed under 40 CFR part 136.6. The SOPs developed by EPA are titled, "Draft Procedure for Trace Element Analysis of Flue Gas Desulfurization Wastewaters Using Perkin Elmer NexION 300D ICP-MS Collision/Reaction Cell Procedure" and "Draft FGD ICP/MS Collision Cell Procedure for Trace Element Analysis in Flue Gas Desulfurization Wastewaters" [U.S. EPA, 2012a; U.S. EPA, 2012b].

In addition, as explained in Section 8.1.2.8, with the exception of the cases where BAT limitations are equivalent to BPT limitations, EPA is proposing that compliance with any final limitations or standards (except pH) based on any of the eight main regulatory options in the proposed rule reflects results obtained from sufficiently sensitive analytical methods. Where EPA has approved more than one analytical method for a pollutant, the Agency expects that permittees would select methods that are able to quantify the presence of pollutants in a given discharge at concentrations that are low enough to determine compliance with effluent limits. For purposes of the proposed anti-circumvention provisions, a method is "sufficiently sensitive" when the sample-specific quantitation level for the wastewater matrix being analyzed is at or below the level of the effluent limit.[118]

14.3 UPSET AND BYPASS PROVISIONS

The CWA, the NPDES permit regulations at §122.41(m) and (n), and the pretreatment regulations at §403.16 and §403.17 allow effluent discharges above permit limits under certain exceptional and limited circumstances. A bypass is an intentional diversion of a wastestream from any portion of a treatment facility to prevent unavoidable loss of life, personal injury, or

[118] For the purposes of the discussion in this rulemaking, the following terms related to analytical method sensitivity are synonymous: "quantitation limit," "reporting limit," "level of quantitation," and "minimum level."

severe property damage. Economic loss caused by delays in production does not constitute severe property damage for the purposes of this regulation. The key requirements for the bypass provisions of a permit are: (1) the bypass must be intentional; (2) prior notice (10 days, if possible) must be provided; and (3) there must be no feasible alternatives to the bypass. A plant does not meet these requirements if it lacks adequate back-up equipment that it should have installed to prevent a bypass during periods of normal operation or maintenance using reasonable engineering judgment. In other cases, intentional bypasses are allowed if required for essential maintenance to ensure efficient operation, as long as these bypasses do not cause the plant to exceed its effluent limitations.

An upset is an exceptional incident in which a facility unintentionally and temporarily cannot comply with its technology-based permit effluent limitations due to factors beyond its reasonable control. An upset does not include noncompliance due to operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventative maintenance, or careless or improper operation. A plant can defend a case in which it exceeds its effluent limitations if the permit holder can demonstrate the following: the cause of the upset can be identified, the permitted facility was being properly operated at the time of the upset, and the permit holder made the required 24-hour notification. In any enforcement proceeding, the burden of proof is on the permit holder, through properly signed operating logs or other relevant evidence, to demonstrate an upset has occurred.

Because Section 510 of the CWA authorizes permit authorities to include more stringent controls than those contained in the federal regulations, any bypass and upset provisions must be included in permits issued by permit authorities to become available to permit holders. Permit authorities should anticipate that permit holders with properly designed and operated wastewater treatment systems would have very few, if any, bypasses or upsets in the course of a five-year NPDES permit that meet the above criteria.

14.4 VARIANCES AND MODIFICATIONS

The CWA requires application of effluent limitations established pursuant to Section 301 or the pretreatment standards of Section 307 to all direct and indirect dischargers. However, the statute provides for the modification of these national requirements in a limited number of circumstances. The Agency has established administrative mechanisms to provide an opportunity for relief from the application of the national effluent limitations guidelines for categories of existing sources for toxic, conventional, and nonconventional pollutants.

As opposed to the bypass and upset provisions that are applicable within the term of a permit, the permit writer develops the variance and alternative limitations at the time of draft permit renewal so that the variance and alternative limitations are subject to public review and comment at the same time the entire permit is put on public notice. The variance and alternative limitations remain in effect for the term of a permit, unless the permit writer modifies it prior to expiration.

A permit applicant must meet specific data requirements before a variance is granted. As the term implies, a variance is an unusual situation, and the permit writer should not expect to routinely receive variance requests. The permit writer should consult 40 CFR §124.62 for procedures on making decisions on the different types of variances, which are discussed below.

14.4.1 <u>Fundamentally Different Factors Variances</u>

As explained above, the CWA requires application of the effluent limitations established pursuant to Section 301 or the pretreatment standards of Section 307 to all direct and indirect dischargers. However, the statute provides for the modification of these national requirements in a limited number of circumstances. Moreover, the Agency has established administrative mechanisms to provide an opportunity for relief from the application of national effluent limitations guidelines and pretreatment standards for categories of existing sources for priority, conventional, and nonconventional pollutants.

EPA may develop, with the concurrence of the state, effluent limitations or standards different from the otherwise applicable requirements for an individual existing discharger if it is fundamentally different with respect to factors considered in establishing the effluent limitations or standards applicable to the individual discharger. Such a modification is known as an FDF variance.

EPA, in its initial implementation of the effluent guidelines program, provided for the FDF modifications in regulations, which were variances from the BPT effluent limitations, BAT limitations for toxic and nonconventional pollutants, and BCT limitations for conventional pollutants for direct dischargers. FDF variances for toxic pollutants were challenged judicially and ultimately sustained by the Supreme Court *Chemical Manufacturers Association v. Natural Resources Defense Council*, 470 U.S. 116, 124 (1985).

Subsequently, in the Water Quality Act of 1987, Congress added new CWA Section 301(n). This provision explicitly authorizes modifications of the otherwise applicable BAT effluent limitations, if a discharger is fundamentally different with respect to the factors specified in CWA Section 304 (other than costs) from those considered by EPA in establishing the effluent limitations. CWA Section 301(n) also defined the conditions under which EPA may establish alternative requirements. Under Section 301(n), an application for approval of a FDF variance must be based solely on (1) information submitted during rulemaking raising the factors that are fundamentally different or (2) information the applicant did not have an opportunity to submit. The alternate limitation must be no less stringent than justified by the difference and must not result in markedly more adverse non-water quality environmental impacts than the national limitation.

EPA regulations at 40 CFR Part 125, subpart D, authorizing the regional administrators to establish alternative limitations, further detail the substantive criteria used to evaluate FDF variance requests for direct dischargers. Thus, 40 CFR 125.31(d) identifies six factors (e.g., volume of process wastewater, age and size of a discharger's facility) that may be considered in determining if a discharger is fundamentally different. The Agency must determine whether, based on one or more of these factors, the discharger in question is fundamentally different from the dischargers and factors considered by EPA in developing the nationally applicable effluent guidelines. The regulation also lists four other factors (e.g., inability to install equipment within the time allowed or a discharger's ability to pay) that may not provide a basis for an FDF variance. In addition, under 40 CFR 125.31(b) (3), a request for limitations less stringent than the national limitation may be approved only if compliance with the national limitations would result in either (a) a removal cost wholly out of proportion to the removal cost considered during development of the national limitations, or (b) a non-water quality environmental impact (including energy requirements) fundamentally more adverse than the impact considered during development of the national limits. The legislative history of Section 301(n) underscores the necessity for the FDF variance applicant to establish eligibility for the variance. EPA's regulations at 40 CFR 125.32(b)(1) impose this burden upon the applicant. The applicant must show that the factors relating to the discharge controlled by the applicant's permit that are claimed to be fundamentally different are, in fact, fundamentally different from those factors considered by EPA in establishing the applicable guidelines. In practice, very few FDF variances have been granted for past ELGs. An FDF variance is not available to a new source subject to NSPS. *DuPont v. Train*, 430 U.S. 112 (1977).

14.4.2 <u>Economic Variances</u>

Section 301(c) of the CWA allows a plant to request a variance for nonconventional pollutants from technology-based BAT effluent limitations due to economic factors, at the request of the plant and on a case-by-case basis. There are no implementing regulations for §301(c); rather, variance requests must be made and reviewed based on the statutory language in CWA §301(c). The economic variance may also apply to nonguideline limits in accordance with 40 CFR §122.21(m)(2)(ii). The applicant normally files the request for a variance during the public notice period for the draft permit. Other filing time periods may apply, as specified in 40 CFR §122.21(m)(2). Specific guidance for this type of variance is provided in *Draft Guidance for Application and Review of Section 301(c) Variance Requests*, dated August 21, 1984, available on EPA's Web site at http://www.epa.gov/npdes/pubs/OWM0469.pdf.

The variance application must show that the modified requirements:

- Represent the maximum use of technology within the economic capability of the owner or operator; and
- Result in further progress toward the goal of discharging no process wastewater.

Facilities in industrial categories other than utilities must conduct three financial tests to determine if they are eligible for a 301(c) variance. Generally, EPA will grant a variance only if all three tests indicate that the required pollution control is not economically achievable and the applicant makes the requisite demonstration regarding “reasonable further progress.”

To meet the second requirement for a 301(c) modification, the applicant must at a minimum demonstrate compliance with all applicable BPT limitations and pertinent water quality standards. In addition, the proposed alternative requirements must reasonably improve the applicant’s discharge.

14.4.3 <u>Water Quality Variances</u>

Section 301(g) of the CWA authorizes a variance from BAT effluent guidelines for certain nonconventional pollutants due to localized environmental factors. These pollutants include ammonia, chlorine, color, iron, and total phenols. As this proposed rule would not establish limitations or standards for any of these pollutants, this variance would not be applicable to this particular rule.

14.4.4 Thermal Discharge Variances

Section 316(a) of the CWA allows variances from effluent limitations for the thermal component of a discharge. See 40 CFR 125, Subpart H for regulations for submitting and reviewing thermal discharge variance requests. Permits may include less stringent alternative thermal effluent limits if the discharger demonstrates that the promulgated limits are more stringent than necessary to ensure the protection and propagation of a balanced, indigenous community of shellfish, fish, and wildlife in and on the water body into which the discharge is made. The applicant must take into account the cumulative impact of its thermal discharge together with all other significant impacts on the species affected.

14.4.5 Net Credits

In some cases, solely because of the level of pollutants in the intake water, plants find it difficult or impossible to meet technology-based limits with BAT/BCT technology. Under certain circumstances, the NPDES regulations allow credit for pollutants in intake water. 40 CFR §122.45(g) establishes the following requirements for net limitations:

- Credit for generic pollutants, such as BOD or TSS, are authorized only where the constituents resulting in the effluent BOD and TSS are similar between the intake water and the discharge;
- Credit is authorized only up to the extent necessary to meet the applicable limitation or standard, with a maximum value equal to the influent concentration;
- Intake water must be taken from the same body of water into which the discharge is made; and
- Net credits do not apply to the discharge of raw water clarifier sludge generated during intake water treatment.

Permit writers are authorized to grant net credits for the quantity of pollutants in the intake water where the applicable ELGs specify that the guidelines are to be applied on a net basis or where the pollution control technology would, if properly installed and operated, meet applicable ELGs in the absence of the pollutants in the intake waters. The proposed ELGs are to be applied on a gross basis.

14.4.6 Removal Credits

Section 307(b)(1) of the CWA establishes a discretionary program for POTWs to grant "removal credits" to their indirect dischargers. Removal credits are a regulatory mechanism by which industrial users may discharge a pollutant in quantities that exceed what would otherwise be allowed under an applicable categorical pretreatment standard because it has been determined that the POTW to which the industrial user discharges consistently treats the pollutant. EPA has promulgated removal credit regulations as part of its pretreatment regulations. See 40 CFR

403.7. These regulations provide that a POTW may give removal credits if prescribed requirements are met. The POTW must apply to and receive authorization from the Approval Authority. To obtain authorization, the POTW must demonstrate consistent removal of the pollutant for which approval authority is sought. Further, the POTW must have an approved pretreatment program. Finally, the POTW must demonstrate that granting removal credits will not cause the POTW to violate applicable Federal, State and local sewage sludge requirements. 40 CFR 403.7(a)(3).

The United States Court of Appeals for the Third Circuit interpreted the Clean Water Act as requiring EPA to promulgate the comprehensive sewage sludge regulations required by CWA §405(d)(2)(A)(ii) before any removal credits could be authorized. *See NRDC v. EPA*, 790 F.2d 289, 292 (3d Cir., 1986); cert. denied., 479 U.S. 1084 (1987). Congress made this explicit in the Water Quality Act of 1987, which provided that EPA could not authorize any removal credits until it issued the sewage sludge use and disposal regulations. On February 19, 1993, EPA promulgated Standards for the Use or Disposal of Sewage Sludge, which are codified at 40 CFR Part 503 (58 FR 9248). EPA interprets the Court's decision in *NRDC v. EPA* as only allowing removal credits for a pollutant if EPA has either regulated the pollutant in part 503 or established a concentration of the pollutant in sewage sludge below which public health and the environment are protected when sewage sludge is used or disposed.

The Part 503 sewage sludge regulations allow four options for sewage sludge disposal: (1) land application for beneficial use, (2) placement on a surface disposal unit, (3) firing in a sewage sludge incinerator, and (4) disposal in a landfill which complies with the municipal solid waste landfill criteria in 40 CFR Part 258. Because pollutants in sewage sludge are regulated differently depending upon the use or disposal method selected, under EPA's pretreatment regulations the availability of a removal credit for a particular pollutant is linked to the POTW's method of using or disposing of its sewage sludge. The regulations provide that removal credits may be potentially available for the following pollutants:

1. If POTW applies its sewage sludge to the land for beneficial uses, disposes of it in a surface disposal unit, or incinerates it in a sewage sludge incinerator, removal credits may be available for the pollutants for which EPA has established limits in 40 CFR Part 503. EPA has set ceiling limitations for nine metals in sludge that is land applied, three metals in sludge that is placed on a surface disposal unit, and seven metals and 57 organic pollutants in sludge that is incinerated in a sewage sludge incinerator. 40 CFR 403.7(a)(3)(iv)(A).
2. Additional removal credits may be available for sewage sludge that is land applied, placed in a surface disposal unit, or incinerated in a sewage sludge incinerator, so long as the concentration of these pollutants in sludge do not exceed concentration levels established in Part 403, Appendix G, Table II. sewage sludge that is land applied, removal credits may be available for an additional two metals and 14 organic pollutants. sewage sludge that is placed on a surface disposal unit, removal credits may be available for an additional seven metals and 13 organic pollutants. sewage sludge that is incinerated in a sewage sludge incinerator, removal credits may be available for three other metals 40 CFR 403.7(a)(3)(iv)(B).

3. When a POTW disposes of its sewage sludge in a municipal solid waste landfill that meets the criteria of 40 CFR Part 258, removal credits may be available for any pollutant in the POTW's sewage sludge. 40 CFR 403.7(a)(3)(iv)(C).

14.5 References

1. U.S. EPA. 2010. NPDES Permit Writer's Manual. EPA-833-K-10-001. Washington, DC. (September).
2. U.S. EPA. 1989. Industrial User Permitting Guidance Manual. EPA 833/R-89-001. Washington, DC. (29 September).
3. U.S. EPA. 2005. Method 245.7, Mercury in Water by Cold Vapor Atomic Fluorescence Spectrometry, Revision 2.0. EPA-821-R-05-001. Washington, DC. (February).
4. U.S. EPA. 2002. Method 1631E, Revision E: Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Fluorescence Spectrometry. EPA-821-R-02-019. Washington, DC. (August).
5. U.S. EPA. 2009. Steam Electric Power Generating Point Source Category: Final Detailed Study. EPA 821-R-09-008. Washington, DC. (October). DCN SE00003.
6. U.S. EPA. 2012a. Draft Procedure for Trace Element Analysis of Flue Gas Desulfurization Wastewaters Using Perkin Elmer NexION 300D ICP-MS Collision/Reaction Cell Procedure. (1 December). DCN SE03868.
7. U.S. EPA. 2012b. Draft FGD ICP/MS Collision Cell Procedure for Trace Element Analysis in Flue Gas Desulfurization Wastewaters. (June). DCN SE03835.
8. U.S. EPA. 1984. Technical Guidance Manual for the Regulations Promulgated Pursuant to Section 301(g) of the Clean Water Act of 1977, 40 CFR Part 125 (Subpart F). Washington, D.C.

APPENDIX A

SURVEY DESIGN AND CALCULATION OF NATIONAL ESTIMATES

Survey Design and Calculation of National Estimates

In June 2010, EPA distributed a survey, entitled The Questionnaire for the Steam Electric Power Generating Effluent Guidelines, to 733 steam electric power plants. The survey was designed to collect technical information related to wastewater generation and treatment, and economic information such as costs of wastewater treatment technologies and financial characteristics of affected companies.

Section 1 of this appendix describes the survey design, and Section 2 provides a summary of the survey responses. Section 3 discusses the weighting procedures, while Section 4 discusses the calculation of national estimates and variance estimation.

A.1 SURVEY DESIGN

This section describes the development of the sample frame, stratification factors, sample design and selection, and the targeted level of precision.

A.1.1 Sample Frame

The sample frame for the Steam Electric Survey is a list of steam electric power generating plants subject to the steam electric power generating effluent guidelines. In addition to listing population elements in terms of contact information (address, phone number, etc.), other information in a sample frame was also used to design the survey.

For this survey, EPA considered the target population to be all fossil- and nuclear-fueled steam electric power plants in the U.S. that report as operating under North American Industry Classification System (NAICS) code 22. EPA constructed the sampling frame using databases that are maintained by the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE), and supplemented it with additional information compiled by EPA. The primary source of information was the 2007 Electric Generator Report (Form EIA-860). Supplemental information was found in Form EIA-923 and in a survey conducted by EPA's Office of Resource Conservation and Recovery. In addition, EPA identified several facilities that started operations after 2007 and obtained necessary information for them.

Using these sources of information, EPA compiled a sample frame containing information on 1,197 steam electric power plants with a total of 2,571 generating units that were within the scope of the survey.

A.1.2 Plant Fuel Classification: the Main Stratification Variable

For this survey, the plant is the sampling unit. EPA stratified the sample frame based on the plant fuel classification, which was determined by the type of fuel used by each of the generating units in operation at the plant. EPA classified each plant's fuel type in the sample frame using the following hierarchical structure:

First, plants were identified as coal plants if the plant had one or more generating units that used coal as its primary or secondary fuel. Since the integrated gasification combined cycle (IGCC) units used coal as the fuel source, they were classified as coal plants.

Second, plants were identified as petroleum coke plants if the plant had one or more generating units that used petroleum coke as its primary or secondary fuel (and the plant was not already classified as a coal plant);

Third, among the remaining plants, those plants for which all units used the same primary fuel type were classified as follows:

- Gas: all units used gas as the primary fuel type, but did not use combined cycle steam turbines;
- Gas-Combined Cycle (CC): all units used gas as the primary fuel type and each used combined cycle steam turbines;
- Oil: all units used oil as the primary fuel type;
- Nuclear: all units were nuclear-fueled;

Finally, all remaining plants with generating units having different fuel types were classified as combination plants as follows:

- Combination - Gas and Gas-CC;
- Combination - Gas and Oil;
- Combination - Gas-CC and Oil;
- Combination - Gas, Gas-CC, and Oil;
- Combination - Gas-CC, Nuclear, and Oil.

A.1.3 Sample Design

The basic sample design of the survey was a stratified design of the plants. The first stratification variable was the plant fuel classification as defined in subsection A.1.2. The second stratification variable was regulatory status, by which each plant was classified as regulated or unregulated. The questionnaire included questions about generating units, and each selected plant was required to complete the questionnaire for every generating unit at the plant.

Another candidate variable for stratification was North American Electric Reliability Corporation (NERC) region but it was not used as a stratification variable. Instead it was used as a sorting variable in systematic sampling to ensure the sample be spread evenly by NERC region; stratum members were sorted by NERC region and every k^{th} member was selected (where k is the ratio of the stratum population size to the stratum sample size). As a result of this systematic sampling, the percentage representation of each NERC region in the sample was expected to be proportional to the size of the region in the population.

All coal and petroleum coke plants were taken with certainty (i.e., all plants in the stratum were selected), whereas for other strata, the sampling rate was 30 percent with a minimum sample size constraint of 10. Therefore, if a stratum population size was less than 34, 10 plants were selected systematically or all plants if there were not more than 10 plants. Due to this constraint, most combination strata were taken with certainty. Table A-1 presents the distribution of the sample frame (plants and generating units) and sample allocation of the plants by design stratum.

Table A-1. Population Distribution of Plants and Generating Units, and Plant Sample Size by Design Stratum

Plant Fuel Classification	Regulatory Status	Sample Frame		Sample
		Plant	**Generating Unit**	**Plant**
Coal	Regulated	344	963	344
	Unregulated	151	340	151
Gas	Regulated	129	310	39
	Unregulated	54	137	16
Gas-Combined Cycle (CC)	Regulated	96	129	29
	Unregulated	276	375	83
Nuclear	Regulated	31	52	10
	Unregulated	32	48	10
Oil	Regulated	23	55	10
	Unregulated	20	38	10
Petroleum Coke	Regulated	0	0	0
	Unregulated	9	9	9
Combination: Gas-CC and Nuclear and Oil	Regulated	1	5	1
	Unregulated	0	0	0
Combination: Gas-CC and Oil	Regulated	2	6	2
	Unregulated	0	0	0
Combination: Gas and Gas-CC	Regulated	20	69	10
	Unregulated	6	23	6
Combination: Gas and Gas-CC and Oil	Regulated	1	4	1
	Unregulated	0	0	0
Combination: Gas and Oil	Regulated	1	4	1
	Unregulated	1	4	1
Total		**1,197**	**2,571**	**733**

The exact number of generating units from these 733 plants to be selected was not known prior to the sample draw because the number of generating units varies by plant and thus would depend on the specific set of plants selected. EPA estimated that about 1,722 generating units would be included in the survey from these 733 plants. This estimated number of generating units was arrived at in the following manner. Generating units within plants that are selected with certainty will automatically be included in the sample. For each non-certainty stratum, EPA estimated the corresponding number of generating units by assuming that the rate of generating units per plant in the sample will be the same as the rate among plants in the sampling frame.

A.1.4 Subsample of Coal and Petroleum Coke Plants for Questionnaire Parts E, F, and G

A subsample of coal and petroleum coke plants was selected to receive additional questions in Parts E, F, and G of the questionnaire. To minimize the burden on small entities, EPA did not collect this additional information from plants that were operated by small entities. Of the 495 coal plants, 55 of these were identified as small entities. The remaining 440 non-small (i.e., not owned by small entities) coal plants were further stratified by whether the plant had a pond or a landfill for waste management as EPA intended to collect information from plants that had ponds and/or landfills containing coal combustion residues (i.e., coal ash or flue gas desulfurization (FGD) wastes). Thus, plants that were classified as "No ponds or landfills" were excluded from subsampling for Parts E, F, and G.

Strata defined by pond-landfill status are as follows:

- *Pond Only – FGD:* Contained all coal plants identified in the sample frame as having a pond with FGD waste as one of its contents, but not a landfill;
- *Pond Only – No FGD:* Contained all coal plants with an ash pond that does not receive FGD waste, but without landfill;
- *Landfill Only – FGD:* Contained all coal plants that had a landfill with FGD waste as one of its contents, but no pond containing coal combustion residues (CCR);
- *Landfill Only – No FGD:* Contained all coal plants that had a landfill containing ash but without FGD wastes, and did not operate a CCR pond;
- *Ponds and Landfills:* Contained all coal plants that had both ponds and landfills containing CCR (either ash or FGD wastes). To minimize the number of strata, no distinction in plants was made by FGD status; and
- *No Ponds or Landfills:* Contained all coal plants that did not store or dispose ash or FGD wastes in a pond or landfill.

Seven plants known to operate leachate collection systems were selected with certainty because EPA wanted to capture this information fully. EPA excluded two coal plants (containing a total of six generating units) from subsampling to avoid the potential burden imposed on these plants. Other plants were subsampled with a sampling rate of 30 percent or 10 plants, whichever was larger for each stratum listed above.

Table A-2 displays the population counts of coal and petroleum coke plants and the corresponding number of generating units, and the sample size for each stratum defined by business size and pond-landfill status. The total sample size for Parts E, F, and G for the coal plants is 94, of which seven were plants with leachate system selected with certainty (shown in parentheses in table A-2). All three non-small petroleum coke plants were included in the subsample that received Parts E, F, and G. These plants were not classified by pond-landfill status. Therefore, the total sample size for Parts E, F, and G was 97, which consisted of 94 coal plants and 3 petroleum coke plants.

Table A-2. Population Counts of Coal/Pet Coke Plants and Generating Units, and Parts EFG Subsample Size by Substratum

Plant Fuel Classification	Business Size	Pond/Landfill	Population Count of Plants	Population Count of Generating Units	Sample Size (Certainty Selection)[b]
Coal	Small	All	55	121	0
	Non-Small	Pond Only – FGD	39	122	12 (1)
		Pond Only – No FGD	99	315	30 (0)
		Landfill Only – FGD	18	34	10 (1)
		Landfill Only – No FGD	55	142	17 (3)
		Both Pond and Landfill	84	256	25 (2)
		No Pond or Landfill	143	307	0
		Avoid Burden[a]	2	6	0
Pet Coke	Small	--	6	6	0
	Non-Small	--	3	3	3
Total			**504**	**1,312**	**97 (7)**

a - EPA excluded two coal plants from receiving parts E, F, and G to avoid overburdening these plants.

b - In parentheses, the number of plants with the leachate system selected with certainty is shown. The sample size includes this number.

The exact number of generating units at the 94 coal plants to be selected was not known prior to the sample draw because the number of generating units varies by plant and thus would depend on the specific set of coal plants selected. Prior to selecting the sample of coal plants, EPA estimated that about 272 generating units at these 94 coal plants would be included in the survey. In addition, there were three petroleum coke generating units (from three plants) that were selected with certainty. Thus, it was expected that there would be about 275 generating units from these 97 plants that would be included in the subsample.

A.1.5 Sample Selection

The regular sample that received the questionnaire without Parts E, F, and G was selected according to the sample design described in subsection A.1.3, resulting in 733 sample plants. The majority of the strata were sampled with certainty by design or the constraint of minimum sample size of 10 if possible. Because of this minimum sample size constraint, almost all combination fuel type strata were certainty strata.

The coal and petroleum coke plants were selected with certainty in the regular sample by design but only a subsample of 97 was selected by a stratified design to receive Parts E, F, and G of the questionnaire. This subsample is called the Parts EFG subsample. The sample results are summarized in Table A-3. The table also presents the base weights, which are the inverse of the sampling probability.

Table A-3. Summary of Sample Selection of Plants

Stratum/Coal Substratum	Population Size	Regular Sample		Subsample	
		Size	Base Weight	Size	Base Weight[a]
Coal – Small Entity	55	55	1	-	
Coal – Pond Only –FGD	39	39	1	12	3.45
Coal – Pond Only –no FGD	101[b]	101	1	30	3.37
Coal – Landfill Only – FGD	18	18	1	10	1.89
Coal – Landfill Only – No FGD	55	55	1	17	3.71
Coal – Both Pond and Landfill	84	84	1	25	3.57
Coal – No Pond and Landfill	143	143	1	-	-
Coal Subtotal	**495**	**495**	**-**	**94**	
Gas-Regulated	129	39	3.31	-	-
Gas-Unregulated	54	16	3.38	-	-
Gas-CC-Regulated	96	29	3.31	-	-
Gas-CC-Unregulated	276	83	3.33	-	-
Nuclear-Regulated	31	10	3.1	-	-
Nuclear-Unregulated	32	10	3.2	-	-
Oil-Regulated	23	10	2.3	-	-
Oil-Unregulated	20	10	2	-	-
Petroleum Coke-Unregulated/Small Entity	6	6	1	-	-
Petroleum Coke-Unregulated/Non-small	3	3	1	3	1
Combination: Gas-CC, Nuclear, and Oil-Regulated	1	1	1	-	-
Combination: Gas-CC and Oil-Regulated	2	2	1	-	-
Combination: Gas and Gas-CC-Regulated	20	10	2	-	-
Combination: Gas and Gas-CC-Unregulated	6	6	1	-	-
Combination: Gas, Gas-CC and Oil-Regulated	1	1	1	-	-
Combination: Gas and Oil-Regulated	1	1	1	-	-
Combination: Gas and Oil-Unregulated	1	1	1	-	-
Non-Coal Subtotal	**702**	**238**	**-**	**3**	**-**
Grand Total	**1,197**	**733**	**-**	**97**	**-**

a - The subsample base weights are for non-certainty coal plants or for certainty petroleum coke plants.

b - This count includes two plants that were not subsampled due to burden consideration.

A.1.6 Expected Precision

An expected precision is usually calculated for a population proportion of 50 percent. Assuming a response rate of 90 percent, the final sample size for the regular sample was expected to be 660 (i.e., 90 percent of the 733 sampled plants). To calculate an expected precision, a design effect of one was assumed, and the finite population correction was ignored to be conservative. The stratification would decrease the design effect but weighting adjustment for nonresponse would increase the design effect. So we assumed that these two effects would cancel each other to make the design effect close to one. Under this scenario, the 95 percent confidence interval for a point estimate of a population proportion of 50 percent was expected to be within ± 3.8 percentage points of the point estimate. If we project the precision for a population proportion of 30 percent, the 95 percent confidence interval would be within ± 3.5 percentage points.

For the subsample of the coal plants for the Parts E, F, and G questionnaire, under the same assumption, it was estimated to have an expected sample size of 85 from the subsample of 94 coal plants. The 95 percent confidence interval for a point estimate of a population proportion of 30 percent was expected to be within +/- 9.2 percentage points of the point estimate.

For generating unit level estimates, under the same assumption made above and further ignoring the clustering effect, the final sample size was expected to be 1,550 (i.e., 90 percent of the expected number of generating units of 1,722 in the sample), and the 95 percent confidence interval for a point estimate of a population proportion of 50 percent was expected to be within +/- 2.5 percentage points of the point estimate.

EPA determined that these precisions were sufficient to meet the objectives of the survey, both for overall plant-level and generating unit level estimates. Moreover, the actual precision is expected to be better than the projected precision when the finite population correlation is incorporation. Furthermore, the plant level response rate was 100 percent, which further adds more precision than projected.

A.2 SURVEY RESPONSES

Of the 733 survey questionnaires sent out, all were returned, so the plant level response rate was 100 percent. However, the survey responses indicate that the frame information on plant eligibility, plant fuel classification, and pond-landfill status for coal and petroleum coke plants was imperfect. The following subsections provide updated information on the eligibility assessment, plant classifications, and pond-landfill classification.

A.2.1 Survey Result of the Eligibility Assessment

Out of 733 respondent plants, a total of 53 plants were found to be ineligible (i.e., out of scope). The reasons for the ineligibility include the following: plant did not have the capability to engage in steam electric power production; plant would be retired by December 31, 2011; or plant did not generate electricity in 2009 using any fossil or nuclear fuels. Of these 53 plants that were deemed ineligible, the distribution over the plants fuel types is as follows: 26 coal plants, 17 gas plants, 6 gas-combined cycle plants, 2 oil plants, 1 petroleum coke plant, and 1 combination plant. To see the distribution of these ineligible plants further classified by regulatory status, see Table A-6 in Section A.3.1, where the number of eligible plants is shown and the number of ineligible plants can be obtained by the balance between the original sample size and the number of eligible plants.

A.2.2 Update of Plant Fuel Type Classification

At the survey design stage, plant fuel type was classified based on the EIA data and other information available to the EPA. After receiving the survey responses, EPA reclassified the sampled plant fuel types using the information from the questionnaire. EPA found that 17 of 680 eligible plants had a fuel type that was different from the original plant fuel type determined at the design stage. The table below provides the final plant fuel classification for all 680 eligible sampled plants based on the survey data.

Table A-4. Final Eligible Sampled Plant Fuel Types

Final Plant Fuel Type (Classified Based on the Survey Data)	Number of Plants
Coal	463
Gas	44
Gas - Combined Cycle	109
Nuclear	20
Oil	13
Petroleum Coke	9
Combination: Gas-CC and Nuclear and Oil	1
Combination: Gas-CC and Oil	3
Combination: Gas and Gas-CC	14
Combination: Gas and Gas-CC and Oil	1
Combination: Gas and Oil	3
Total	**680**

A.2.3 Survey Results for the Coal and Petroleum Coke Plants and the Subsample for Parts E, F, and G

The 504 coal and petroleum coke plants identified at the survey design stage were selected with certainty, but only a subsample of 97 of these plants was selected to receive Parts E, F, and G of the questionnaire using the sample design described in Section A.1.4.

Of the 94 coal plants that were selected to receive Parts E, F, and G, 92 plants remained eligible after receiving the survey responses. Of the 3 petroleum coke plants selected to receive Parts E, F, and G, two plants remained eligible after receiving the survey responses.

Further, the updated pond-landfill status for each plant was obtained from Part A, which was completed by every regular sample plant, including those that were not subject to subsampling. Based on the survey information, EPA found that some of the pond-landfill for coal and petroleum coke plants were incorrectly classified in the frame. The table below provides the final summary of how these coal and petroleum coke plants were classified based on the updated survey data.

Table A-5. Frequency Summary by the Updated Pond-Landfill Status for Eligible Coal Plants and by Petroleum Coke Status in the Population and in the Parts EFG Subsample

Updated Pond/Landfill Stratum (Based on the Survey Data)	Eligible Plants in the Population	Eligible Plants in Subsample
Coal - Both Pond and Landfill	192[a]	56
Coal - Landfill Only – FGD	12	1
Coal - Landfill Only – No FGD	22	1
Coal - Pond Only – FGD	37	7
Coal - Pond Only – No FGD	112[a]	27
Coal - No Pond or Landfill	88	0
Petroleum Coke	9	2
Total	**472**	**94**

a - The count includes coal plants, which were excluded from subsampling due to concerns of burden.

A.3 WEIGHTING OF THE SURVEY DATA

This section describes the weighting procedure for the regular sample and the subsample at the plant level.

A.3.1 Plant-Level Weighting

Weighting the survey data starts with calculating the base weight, which is the inverse of the sampling probability, and then nonresponse adjustment is usually applied. Nonresponse adjustment entails adjusting the base weight for both non-response and unknown eligibility. However for the Steam Electric Survey, there was neither non-response nor sample plants with unknown eligibility. Thus, there was no need for EPA to apply this type of weighting adjustment. Consequently, the final weight for this survey is defined as the base weight for all sample plants in the regular sample (note that the Parts EFG subsample is also included in the regular sample). The ineligible plants in the sample represent the ineligible population and are given the same base weights as well.

Reclassification of stratification variables does not affect the weighting because the weight is the inverse of the selection probability, which is determined at the time of sample selection. However, a reclassified stratum now consists of plants from other design strata that may have different weights, and this would affect analyses that would be done using the updated classification. Table A-6 shows the original population and sample sizes, the number of sample plants that were eligible among the original regular sample, the final weight, the reclassified number of eligible plants that includes plants from other strata due to reclassification, and the estimated population size based on updated classification, which was calculated as the sum of final weights of the reclassified plants.

Table A-6. Estimated Eligible Population Size for Survey-Based Fuel Type Classification

Fuel Classification	Regulatory Status	Population Size in Frame	Original Sample Size	Number of Eligible Plants	Final Weight	Reclassified No. of Eligible Plants[a]	Estimated Population Size[b]
Coal	Regulated	344	344	328	1.0	323	**323**
	Unregulated	151	151	141	1.0	140	**140**
Gas	Regulated	129	39	29	3.308	31	**98**
	Unregulated	54	16	9	3.375	13	**39**
Gas-CC	Regulated	96	29	28	3.310	30	**92**
	Unregulated	276	83	78	3.325	79	**258**
Nuclear	Regulated	31	10	10	3.1	10	**31**
	Unregulated	32	10	10	3.2	10	**32**
Oil	Regulated	23	10	9	2.3	8	**18**
	Unregulated	20	10	9	2.0	5	**10**
Petroleum Coke [a]	Regulated	0	0	0	-	1	**1**
	Unregulated	9	9	8	1.0	8	**8**
Comb: Gas-CC, Nuclear & Oil	Regulated	1	1	1	1.0	1	**1**
	Unregulated	0	0	0	-	-	**-**
Comb: Gas-CC and Oil	Regulated	2	2	2	1.0	2	**2**
	Unregulated	0	0	0	-	1	**1**
Comb: Gas and Gas-CC	Regulated	20	10	10	2.0	12	**26**
	Unregulated	6	6	5	1.0	2	**2**
Comb: Gas and Gas-CC and Oil	Regulated	1	1	1	1.0	1	**1**
	Unregulated	0	0	0	-	0	**-**
Comb: Gas and Oil	Regulated	1	1	1	1.0	0	**-**
	Unregulated	1	1	1	1.0	3	**5**
Total		**1,197**	**733**	**680**	**-**	**680**	**1,088**

a - The count includes reclassified plants initially belonging to a different design stratum.

b - This column shows the sum of the final weights of reclassified plants that was rounded to the nearest integer.

While the column “Number of Eligible Plants” provides the number of eligible plants based on the original fuel type classification (regardless of their reclassified fuel type), the column named “Reclassified Number of Eligible Plants” gives the number of eligible plants based on the reclassification of their fuel type. For example, there were 29 eligible plants among those plants originally classified as gas – regulated but 31 plants fell in the class after reclassification based on the survey response. Therefore, it should be noted that the estimated population size in the last column is the (rounded) sum of the final weights of the reclassified eligible plants as each plant carries its own final weight wherever it is reclassified. It is not the same in general as the product of the reclassified number of eligible plants (which may have different final weights due to reclassification) and the final weight for the original stratum.[119]

In general, the estimated population size is smaller than the frame population size for due to reclassification and loss of ineligible plants. However, it could be larger if more plants were reclassified into that stratum. The overall estimated population size for this survey is 9.9 percent less than the frame population size due to loss of ineligible plants.

The same weighting principle applies to the subsample of 97 coal or petroleum coke plants that received Parts E, F, and G because this subsample was selected from the census of the coal/petroleum coke population. However, there is an important departure from the weighting method used for the full (regular) sample because the subsample was made also to cover plants, which were not subject to subsampling. Moreover, it was necessary to do more because almost half of the plants in the subsample changed their stratification. So, post-stratification weight adjustment was used to address these issues, which is further explained in Section A.3.2 below.

A.3.2 Plant-Level Weighting for the Parts EFG Subsample

The subsample of 97 plants was selected from the 504 coal or petroleum coke plants identified in the sample frame to receive Parts E, F, and G of the questionnaire. However, 206 plants were not subject to subsampling (including plants operated by small entities (61), plants with no CCR pond or landfill (143), and plants excluded to avoid overburdening (2)). Nevertheless, EPA wanted to use the subsample to represent the whole population. Therefore, non-coverage weighting adjustment was performed for the subsample.

One subsample was selected for Parts E, F, and G but Part E items do not have as much bearing with the Pond-Landfill status as do Parts F and G items. Part E of the questionnaire collected information about metal cleaning wastes, which is relevant to all plants, including plants with or without CCR ponds or landfills. On the other hand, since Parts F and G are applicable only to coal or petroleum coke plants with CCR ponds or landfills, the weighting had to account for the Pond-Landfill status. To address the difference in the characteristics of Part E items and Parts F and G items, two different sets of weights were developed as explained below: one set for Part E and another set for Parts F and G.

A.3.2.1 Development of the Final Weight for Part E

As explained in the previous section, the relevant Part E items do not have much bearing with the stratification by the Pond-Landfill status. Therefore, non-coverage weight adjustment was done so that the sum of the adjusted weights of the subsample of 94 eligible plants is equal to the eligible population size of 472 (504 frame size minus 32 plants that were ineligible or were reclassified as non-coal or non-petroleum coke plants) regardless of their Pond-Landfill status. This amounts to using a single weighting adjustment factor that is given by 472 divided by the total sum of the base weights of 94 eligible subsample plants, which is 290.4, so the factor is

[119] In the Gas – Regulated stratum, there are 31 reclassified eligible plants, which consist of 29 original plants and 2 reclassified from the Coal stratum (see Table A-6). Therefore, the estimated eligible population size for the Gas – Regulated stratum is obtained by 29*3.308+2*1 = 97.932, which is rounded to 98.

472/290.4 = 1.6253. This factor is multiplied by the subsampling base weights to obtain the Part E final weights.

A.3.2.2 Development of the Final Weight for Parts F and G

Since Parts F and G are only applicable to coal or petroleum coke plants with a CCR pond or landfill, the relevant population for Parts F and G consists of all eligible coal plants with either a CCR pond or a CCR landfill or petroleum coke plants. Therefore, the subsample of 94 coal or petroleum coke plants was weighted so that the final weights sum to the eligible population size of 384 coal plants with a pond or landfill and petroleum coke plants (i.e., 384 = 472 eligible coal and petroleum coke plants – 88 plants without pond/landfill).

As shown in Table A-5 above, after the reclassification process, it was found that the numbers of sampled plants in some updated substrata are very small (i.e., in the updated “Coal – Landfill Only – FGD” and “Coal – Landfill Only – No FGD” strata, there was only 1 plant in each received Parts E, F, and G of the questionnaire). Moreover, the ratios between the population sizes and sample sizes vary widely. This indicates that if updated substrata are used as post-strata for weight adjustment, the resulting weights will be very unstable, and it will cause instability of the variance estimate. Therefore, small substrata were collapsed to form the post-strata. With this goal in mind, the updated substrata “Coal – Landfill Only – FGD” and “Coal – Landfill Only – No FGD” were collapsed into the updated substratum “Coal – Both Pond and Landfill” resulting in four post-strata as follows:

- Post-stratum 1: Coal – Both Pond and Landfill, Coal – Landfill Only – FGD, and Coal – Landfill Only – No FGD;
- Post-stratum 2: Coal - Pond Only – FGD;
- Post-stratum 3: Coal - Pond Only – No FGD;
- Post-stratum 4: Petroleum Coke.

Note that all post-strata above were defined using the updated strata.

The weight adjustment factors presented below were used to obtain the final survey weights, which are the product of the adjustment factor and the initial base weight in each post-stratum. The weight adjustment factor is defined as the ratio of the population size to the sum of base weights of eligible subsample plants in the post-stratum.

Table A-7. Weight Adjustment Factors for the Four Post-Strata

Post Stratum Number	Updated Substratum	Population Size	Eligible Sample Size	Weight Adjustment Factor
1	Coal - Both Pond and Landfill Coal - Landfill Only – FGD Coal - Landfill Only - No FGD	226	58	1.27
2	Coal - Pond Only – FGD	37	7	1.86
3	Coal - Pond Only - No FGD	112	27	1.24
4	Pet-Coke - Selected for EFG	9	2	4.5
Total		**384**	**94**	

A.4 ESTIMATION METHOD

This section presents the general methodology and equations for calculating estimates from the survey.

A.4.1 National Estimates

The survey collected many sub-items below the plant level. For example, some characteristics of generating units were collected. However, sub-units (e.g., generating unit) below the plant were all selected, therefore the weight appropriate for weighted analysis is the same as the plant level weight. Some of the missing data were filled in using data from the 2009 EIA database, which is the same year basis as the data provided in response to the questionnaire. A small amount of missing data remains, primarily among the sub-plant level variables. Nevertheless, in the discussion below, no adjustments are made for missing data. For most variables, the consequence of this is negligible due to the small amount of missing data.

There are three levels of analytical unit (plant, generating unit, sub-generating-unit element) with item characteristics at each of these levels. Let w_{hi} be the sampling weight for plant i within variance stratum h.[120] The variance stratum is defined in the following section, where variance estimation is explained.

Different formulas are used for point estimation depending on the type of estimate. Since estimation of the population total is the most basic, and many estimates can be defined using the total estimates, we first discuss estimation of the population total.

Suppose that the parameter of interest is the population total (Y) of a variable denoted by y. Then the plant-level weighted total of the y-values for plant i in variance stratum h, $\hat{y}_{hi}$, is defined as:

[120] We could use the design stratum to give the estimation formula but to tie point estimation with variance estimation, it is more convenient to use the variance stratum.

$$\hat{y}_{hi} = \begin{cases} w_{hi} y_{hi} & \text{if the } y\text{-variable is at the plant level} \\ w_{hi} \sum_j y_{hij} & \text{if the } y\text{-variable is at the generating-unit level} \\ w_{hi} \sum_j \sum_k y_{hijk} & \text{if the } y\text{-variable is at the sub-generating-unit level} \end{cases} \quad (1)$$

Using this, the total Y is estimated by:

$$\hat{Y} = \sum_{h=1}^{H} \sum_{i=1}^{n_h} \hat{y}_{hi} \quad (2)$$

where H is the total number of variance strata, and n_h is the number of sample plants in variance stratum h for the analysis. Note that the strata involved in analysis depend on the analysis variables (items). If the variable is one of the Part E, F, or G items, then the strata are those for the Parts EFG subsample. The "hat" over the population parameter indicates an estimate of the parameter. When a weighted frequency (e.g., the total number of generating units with a fly wet handling system) is calculated, the same formula is used, but the analysis variable y has a value of one if the case has the attribute (e.g., having a fly wet handling system), and a value of zero otherwise.

To estimate the population mean, we need an estimate of the eligible population size (N), and it is estimated by the sum of the weights as follows:

$$\hat{N} = \sum_{h=1}^{H} \sum_{i=1}^{n_h} \hat{N}_{hi} = \sum_{h=1}^{H} \sum_{i=1}^{n_h} w_{hi} c_{hi} \,. \quad (3)$$

where c_{hi} is the count of the analysis units for plant i in variance stratum h – it is one if the analysis unit is the plant, otherwise the count of sub-plant level units.

An estimate of the population mean ($\bar{Y}$) for y-variable is given by:

$$\hat{\bar{Y}} = \frac{\hat{Y}}{\hat{N}} \,. \quad (4)$$

Population proportions are estimated by (4) if the y-variable is dichotomous. The estimate given by (4) is defined as the ratio of two total estimates, so it is called the ratio estimate. When the population parameter of interest is a ratio (R) of two analysis variables y and x, then it is defined as the ratio of two estimated totals:

$$\hat{R} = \frac{\hat{Y}}{\hat{X}} \quad (5)$$

A.4.2 Variance Estimation

The original regular sample was selected by a stratified equal probability sample of plants, and some strata are very small in size. For variance estimation, small design strata with one or two plants selected in Combination strata were collapsed into one stratum. This redefined stratum and other original design strata were used as strata for variance estimation, and for this reason, they are called variance strata.

For the Parts EFG subsample, a stratified equal probability sampling method was also used except for those coal plants with a leachate collection system, which were selected with certainty. These original substrata were also the variance strata for variance estimation for the variables from Parts E, F, and G.

Any elements below the plant level such as the generating unit were selected with certainty. Therefore, the sample design can be regarded as a single stage cluster sample for items at the sub-plant level, where the plants are the primary sampling unit (PSU) and sub-plant level elements are the secondary sample unit (SSU). Furthermore, the sub-generating-unit element under the generating unit can be considered as the tertiary sampling unit (TSU). The PSUs are usually used as variance units for variance estimation, where the variance of an estimate (e.g., total) is calculated as the variability of PSU estimates, as is the case for the Steam Electric Survey. The variance estimate for the total estimate given in (2) is given by:

$$\hat{V}(\hat{Y}) = \sum_{h=1}^{H} \left(1 - f_h\right) \sum_{i=1}^{n_h} \left(\hat{y}_{hi} - \bar{\hat{y}}_h\right)^2 \Big/ \left(n_h - 1\right) \qquad (6)$$

where $f_h = n_h / N_h$, which is the variance stratum sampling fraction, n_h is the plant sample size of the variance stratum for the analysis, N_h is the variance stratum population size, and $\bar{\hat{y}}_h = \sum_{i=1}^{n_h} \hat{y}_{hi} / n_h$. The factor $1 - f_h$ in (6) is called the finite population correction (FPC). The variance estimate for a non-linear statistic such as the ratio estimate given by equation (4) or (5) needs a different formula or technique.

There are two main approaches for estimating the variance of a non-linear point estimate: the Taylor linearization method and resampling methods. For the analyses in all parts (except for Parts F and G), the Taylor method was used. Since complex post-stratification weighting was used for Parts F and G items, a resampling method known as the jackknife was chosen for the analysis, for which the jackknife replicate weights were developed for the Parts F and G. For analysis of Parts F and G variables the Taylor method could have been used as well, but the jackknife variance estimates were used since they are less biased. The jackknife and FPC factors for analysis of variables from Parts F and G are provided in the following table.

Table A-8. The Jackknife and Finite Population Correction (FPC) Factors for Parts F and G

Variance Stratum	Description of Variance Stratum	Number of Replicates	Jackknife Factor	FPC Factor
1	Coal – Both Pond and Landfill	23	0.95652	0.77841
2	Coal – Landfill Only – FGD	9	0.88889	0.59805
3	Coal – Landfill Only – No FGD	14	0.92857	0.78810
4	Coal – Pond Only - FGD	11	0.90909	0.78898
5	Coal – Pond Only – No FGD	28	0.96429	0.76230
6	Coal – All other types	7	0.85714	0.24871
7	Petroleum coke – Selected for EFG	2	0.5	0.77778

APPENDIX B

MODIFIED DELTA-LOGNORMAL DISTRIBUTION

APPENDIX B
Contents

This appendix describes the modified delta-lognormal distribution and the estimation of the plant-specific long-term averages and plant-specific variability factors used to calculate the limitations and standards. This appendix provides the statistical methodology that was used to obtain the results presented in Section 13 of the Technical Development Document. For simplicity, in the remainder of this appendix, references to "limitations" include "standards".

The term "detected" in this document refers to analytical results measured and reported above the sample-specific quantitation limit. Thus, the term "non-detected" refers to values that are below the method detection limit (MDL) and those measured by the laboratory as being between the MDL and the quantitation limit (QL) in the original data (before adjusting for baseline).

B.1 Basic Overview of the Modified Delta-Lognormal Distribution

EPA selected the modified delta-lognormal distribution to model pollutant effluent concentrations from the steam electric industry in developing the long-term averages and variability factors. A typical effluent dataset from EPA sampling, CWA 308 sampling, or from a plant's self-monitoring consists of a mixture of measured (detected) and non-detected values. The modified delta-lognormal distribution is appropriate for such datasets because it models the data as a mixture of detected measurements that follow a lognormal distribution and non-detect measurements that occur with a certain probability. The model also allows for the possibility that non-detected measurements occur at multiple sample-specific detection limits. Because the data appeared to fit the modified delta-lognormal model reasonably well, EPA has determined that this model is appropriate for these data.

The modified delta-lognormal distribution is a modification of the 'delta distribution' originally developed by Aitchison and Brown.[121] While this distribution was originally developed to model economic data, other researchers have shown the application to environmental data.[122] The resulting mixed distributional model, that combines a continuous density portion with a discrete-valued spike at zero, is also known as the delta-lognormal distribution. The delta in the name refers to the proportion of the overall distribution contained in the discrete distributional spike at zero, that is, the proportion of zero amounts. The remaining non-zero amounts are grouped together and fit to a lognormal distribution.

EPA modified this delta-lognormal distribution to incorporate multiple detection limits. In the modification of the delta portion, the single spike located at zero is replaced by a discrete distribution made up of multiple spikes. Each spike in this modification is associated with a distinct sample-specific detection limit associated with non-detected (ND) measurements in the database. A lognormal density is used to represent the set of detected values. This modification of the delta-lognormal distribution is illustrated in the figure below.

[121] Aitchison, J. and J.A.C. Brown. 1963. The Lognormal Distribution. Cambridge University Press, pages 87-99.

[122] Owen, W.J. and T.A. DeRouen. 1980. "Estimation of the Mean for Lognormal Data Containing Zeroes and Left-Censored Values, with Applications to the Measurement of Worker Exposure to Air Contaminants." *Biometrics*, 36:707-719.

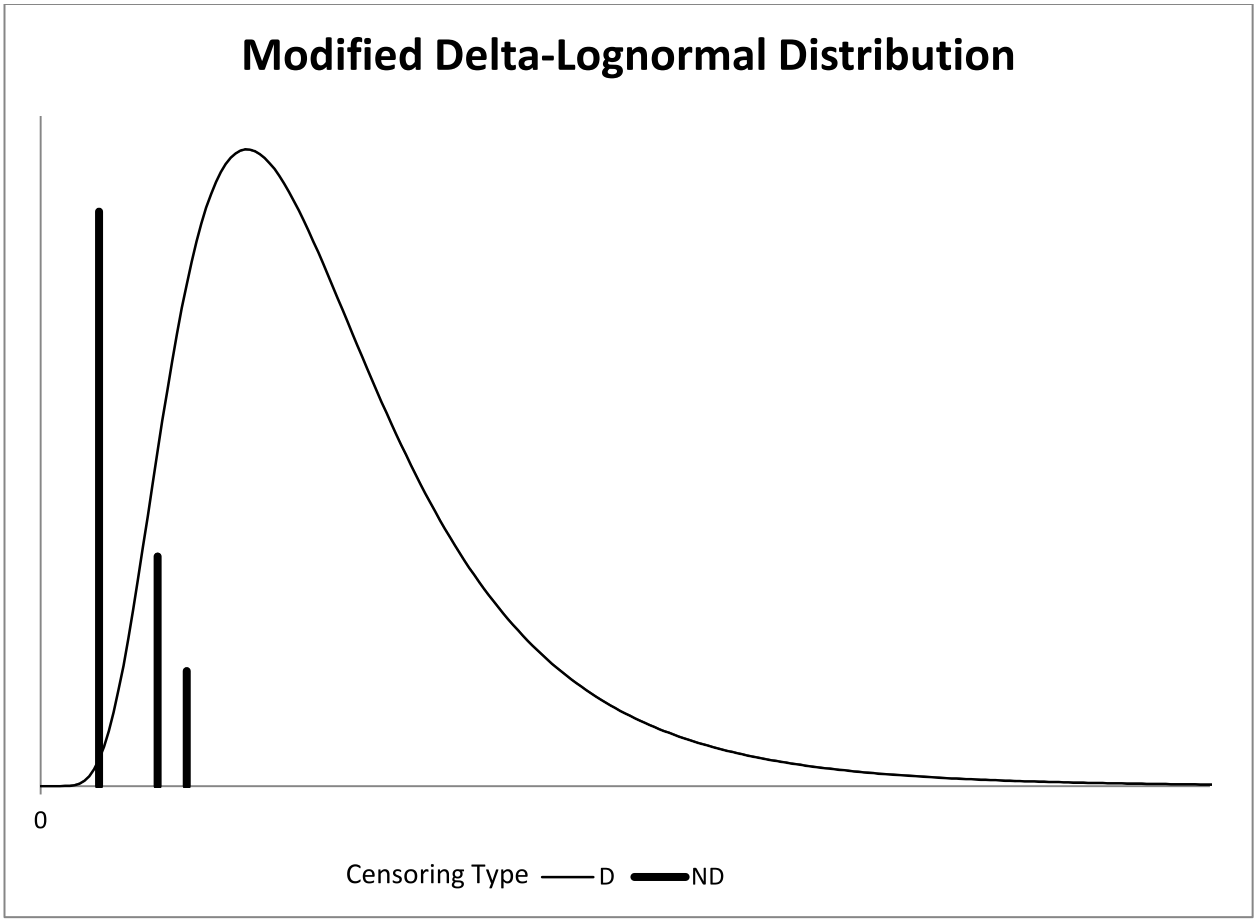


Figure B-1. Modification of the Delta-Lognormal Distribution

The following two sections describe the delta and lognormal portions of the modified delta-lognormal distribution in further detail.

B.2 Continuous and Discrete Portions of the Modified Delta-Lognormal Distribution

In the discrete portion of the modified delta-lognormal distribution, the non-detected values correspond to the k reported sample-specific detection limits. In the model, δ represents the proportion of non-detected values and is the sum of δ_i, $i=1,\ldots,k$, which represents the proportion of non-detected values associated with the i^{th} distinct detection limit. By letting D_i equal the value of the i^{th} smallest distinct detection limit in the dataset and letting the random variable X_D represent a randomly chosen non-detected measurement, the cumulative distribution function of the discrete portion of the modified delta-lognormal model can be mathematically expressed as:

$$Pr(X_D \leq c) = \frac{1}{\delta} \sum_{i:D_i \leq c} \delta_i \text{ , } c > 0 \qquad (1)$$

The mean and variance of this discrete distribution can be calculated using the following formulas:

$$E(X_D) = \frac{1}{\delta}\sum_{i=1}^{k} \delta_i \, D_i \tag{2}$$

$$Var(X_D) = \frac{1}{\delta}\sum_{i=1}^{k} \delta_i (D_i - E(X_D))^2 \tag{3}$$

The continuous, lognormal portion of the modified delta-lognormal distribution was used to model the detected measurements. The cumulative probability distribution of the continuous portion of the modified delta-lognormal distribution can be mathematically expressed as:

$$Pr(X_C \leq c) = \Phi\left(\frac{ln(c) - \mu}{\sigma}\right) \tag{4}$$

where the random variable X_C represents a randomly chosen detected measurement, $\Phi(\cdot)$ is the cumulative distribution function of the standard normal distribution, and μ and σ are parameters of the distribution.

The expected value, $E(X_C)$, and the variance, $Var(X_C)$, of the lognormal distribution can be calculated as:

$$E(X_c) = exp\left(\mu + \frac{\sigma^2}{2}\right) \tag{5}$$

$$Var(X_C) = \left(E(X_C)\right)^2 (exp(\sigma^2) - 1) \tag{6}$$

B.3 Combining the Continuous and Discrete Portions

The continuous portion of the modified delta-lognormal distribution is combined with the discrete portion to model data that contain a mixture of non-detected and detected measurements. It is possible to fit a wide variety of observed effluent data to the modified delta-lognormal distribution. Multiple detection limits for non-detect measurements are incorporated, as are measured ("detected") values. The same basic framework can be used even if there are no non-detected values in the dataset (in this case, it is the same as the lognormal distribution). Thus, the modified delta-lognormal distribution offers a large degree of flexibility in modeling effluent data.

The modified delta-lognormal random variable *U* can be expressed as a combination of three other independent variables as follows:

$$U = I_U X_D + (1 - I_U) X_c \qquad (7)$$

where X_D represents a random non-detect from the discrete portion of the distribution, X_C represents a random detected measurement from the continuous lognormal portion, and I_U is a variable indicating whether any particular random measurement, *U*, is non-detected or detected (that is, I_U=1 if *u* is non-detected, and I_U=0 if *u* is detected). Using a weighted sum, the cumulative distribution function from the discrete portion of the distribution (equation 1) can be combined with the function from the continuous portion (equation 4) to obtain the overall cumulative probability distribution of the modified delta-lognormal distribution:

$$Pr(U \leq c) = \sum_{i:D_i \leq c} \delta_i + (1 - \delta)\Phi\left(\frac{ln(c) - \mu}{\sigma}\right) \qquad (8)$$

The expected value of the random variable *U* can be derived as a weighted sum of the expected values of the discrete and continuous portions of the distribution (equations 2 and 5, respectively) as follows:

$$E(U) = \delta E(X_D) + (1 - \delta)E(X_C) \qquad (9)$$

In a similar manner, the expected value of U^2 can be written as a weighted sum of the expected values of the squares of the discrete and continuous portions of the distribution:

$$E(U^2) = \delta E(X_D^2) + (1 - \delta)E(X_C^2) \qquad (10)$$

Although written in terms of *U*, the following relationship holds for all random variables:

$$E(U^2) = Var(U) + \left(E(U)\right)^2 \qquad (11)$$

Now using equation 11 to solve for *Var(U)*, and applying the relationships in equations 9 and 10, the variance of *U* is given by

$$Var(U) = \delta\left(Var(X_D) + \left(E(X_D)\right)^2\right) + (1 - \delta)\left(Var(X_C) + \left(E(X_C)\right)^2\right) - \left(E(U)\right)^2 \qquad (12)$$

Thus the modified delta-lognormal distribution can be described by the following parameters: the *k* distinct detection limits, D_i, and their corresponding probabilities, $\delta_i, i = 1, \ldots, k,$ and the parameters μ and σ of the lognormal distribution for detected values.

B.4 Autocorrelation

Effluent data from wastewater treatment technologies may be autocorrelated. For example, positive autocorrelation is present in the data if the effluent concentration was relatively high one day and was likely to remain high on the next and possibly succeeding days.

For data with autocorrelation, statistical time series are appropriate for modeling the data. There are many time series models that might be considered for modeling wastewater measurements. One method of modeling autocorrelation is by using an autoregressive lag-1 model, designated as an AR(1) model. The AR(1) model is a reasonable model for many series of wastewater measurements. The AR(1) model has one parameter, ρ_1, the correlation between log-transformed measurements from successive sampling events equally spaced over time, otherwise referred to as the lag-1 correlation. Unless specified otherwise, ρ_1 is assumed to be zero, i.e., no autocorrelation.

The autocorrelation affects the mean and variance estimates. Specifically, when the data are deemed to be positively autocorrelated, the variance estimate from samples collected on successive days will be less than the variance of the long-term concentration series, and thus the variance estimates from the sampled days should be adjusted for the correlation in order to obtain an accurate estimate of the variance for the long-term series. Adjustments for autocorrelation have been made whenever appropriate. See Section 13 of the Technical Development Document for a discussion of the use of autocorrelation in calculating the limits.

The equations in Section B.5 were used when the autocorrelation was assumed to be zero; otherwise the equations in Section B.6 were used.

B.5 Plant-Specific Estimates Under the Modified Delta-Lognormal Distribution

In order to use the modified delta-lognormal model, the parameters of the distribution must be estimated from the data. These estimates are then used to calculate the limitations. The following assumes that the parameter estimates are calculated from *n* observed daily values.

The parameters δ_i and δ are estimated from the data using the following formulas:

$$\hat{\delta}_i = \frac{1}{n}\sum_{j=1}^{n_d} I\left(d_j = D_i\right)$$
$$\hat{\delta} = \frac{n_d}{n} \qquad (13)$$

where n is the number of measurements (both detected and non-detected), $I(\cdot)$ is an indicator function equal to one if the argument is true (and zero otherwise), d_j, $j = 1,\dots, n_d$, is the detection limit for the j^{th} non-detected measurement, and n_d is the total number of non-detected measurements. The "hat" over the parameters indicates that these values are estimated from the data.

The expected value and the variance of the discrete portion of the modified delta-lognormal distribution can be estimated from the data as:

$$\hat{E}(X_D) = \frac{1}{\hat{\delta}}\sum_{i=1}^{k} \hat{\delta}_i\, D_i \qquad (14)$$

$$\hat{V}ar(X_D) = \frac{1}{\hat{\delta}}\sum_{i=1}^{k} \hat{\delta}_i \left(D_i - \hat{E}(X_D)\right)^2 \qquad (15)$$

The parameters μ and σ of the continuous portion of the modified delta-lognormal distribution are estimated from

$$\hat{\mu} = \sum_{i=1}^{n_c} \frac{ln(x_i)}{n_c} \qquad (16)$$

$$\hat{\sigma}^2 = \sum_{i=1}^{n_c} \frac{(ln(x_i) - \hat{\mu})^2}{n_c - 1} \qquad (17)$$

where x_i is the i^{th} detected measurement and n_c is the number of detected measurements (note that $n = n_d + n_c$).

The expected value and the variance of the lognormal portion of the modified delta-lognormal distribution can be calculated from the data as:

$$\hat{E}(X_C) = exp\left(\hat{\mu} + \frac{\hat{\sigma}^2}{2}\right) \qquad (18)$$

$$\hat{V}ar(X_C) = \left(\hat{E}(X_C)\right)^2 (exp(\hat{\sigma}^2) - 1) \qquad (19)$$

Finally, the expected value and variance of the modified delta-lognormal distribution can be estimated using the following formulas:

$$\hat{E}(U) = \hat{\delta}\hat{E}(X_D) + \left(1 - \hat{\delta}\right)\hat{E}(X_C) \qquad (20)$$

$$\hat{V}ar(U) = \hat{\delta}\left(\hat{V}ar(X_D) + \left(\hat{E}(X_D)\right)^2\right) + \left(1 - \hat{\delta}\right)\left(\hat{V}ar(X_C) + \left(\hat{E}(X_C)\right)^2\right) - \left(\hat{E}(U)\right)^2 \qquad (21)$$

Equations 18 through 21 are particularly important in the estimation of the plant long-term averages and variability factors as described in the following sections.

B.5.1 Dataset Requirements

The parameter estimates for the lognormal portion of the modified delta-lognormal distribution can be calculated with as few as two distinct detected values in a dataset. (In order to estimate the variance of the modified delta-lognormal distribution, at least two distinct detected values are required.)

For this rulemaking, EPA used a plant dataset for a pollutant to calculate the plant-specific long-term average and variability factor if the dataset contained three or more observations with at least two distinct detected concentration values. If the plant dataset for a pollutant did not meet these requirements, EPA used an arithmetic average to calculate the plant-specific long-term average and excluded the dataset from the variability factor calculations (since the variability could not be calculated in this situation).

B.5.2 Estimation of Plant-Specific Long-Term Averages and Variability Factors

If a dataset for a pollutant at a plant meets the requirement described in Section B.5.1 above, then the plant-specific long-term averages and variability factors are estimated as described in the subsections below. Furthermore, another assumption made in the estimating procedures described below is that no autocorrelation exists in the data (i.e., daily measurements are independent).

B.5.2.1 Estimation of Plant-Specific Long-Term Averages (LTA)

The plant specific long-term average (LTA) is calculated as follows:

$$LTA = \hat{E}(U) = \hat{\delta}\hat{E}(X_D) + \left(1-\hat{\delta}\right)\hat{E}(X_C) = \sum_{i=1}^{k}\hat{\delta}_i D_i + \left(1-\hat{\delta}\right)exp(\hat{\mu}+0.5\hat{\sigma}^2) \qquad (22)$$

Section B.5 contains all the formulas used for each of the expressions above. In the case where there are less than two distinct detected values, the variance in the above formula cannot be calculated. In this case, the long-term average is calculated as the arithmetic mean of the available data (consisting of detected values and detection limits).

B.5.2.2 Estimation of Plant-Specific Daily Variability Factors (VF1)

The plant-specific daily variability factor is the ratio of the 99th percentile to the long-term average and is calculated as follows:

$$VF1 = \frac{\hat{P}_{99}}{\hat{E}(U)} = \frac{\hat{P}_{99}}{LTA} \qquad (23)$$

Below a description is given of how the 99th percentile of the modified delta-lognormal distribution is estimated, including how multiple detection limits are accounted for when estimating the 99th percentile.

Under the modified delta-lognormal distribution, if $D_1 < D_2 < \ldots < D_k$ are the k observed detection limits expressed in increasing order, then let

$$\hat{q}_m = \sum_{i=1}^{m}\hat{\delta}_i + \left(1-\hat{\delta}\right)\Phi\left(\frac{ln(D_m)-\hat{\mu}}{\hat{\sigma}}\right), m = 1, \ldots, k \qquad (24)$$

where $\Phi(\cdot)$ is the cumulative distribution function of the standard normal distribution. If all *k* of the $\hat{q}_m$ values are below 0.99, then

$$\hat{P}_{99} = exp\left(\hat{\mu} + \hat{\sigma} \cdot \Phi^{-1}\left(\frac{0.99 - \hat{\delta}}{1 - \hat{\delta}}\right)\right) \quad (25)$$

where $\Phi^{-1}(p)$ is the p^{th} percentile of the standard normal distribution. Otherwise, find j such that D_j is the smallest detection limit for which $\hat{q}_j \geq 0.99$, and let $\hat{q}^* = \hat{q}_j - \hat{\delta}_j$. Then the 99th percentile is found by the following:

$$\hat{P}_{99} = \begin{cases} D_j & if\ \hat{q}^* < 0.99 \\ exp\left(\hat{\mu} + \hat{\sigma} \cdot \Phi^{-1}\left(\frac{0.99 - \sum_{i=1}^{j-1} \hat{\delta}_i}{1 - \hat{\delta}}\right)\right) & if\ \hat{q}^* \geq 0.99 \end{cases} \quad (26)$$

B.5.2.3 Estimation of Plant-Specific Monthly Variability Factors (VF4)

Plant-specific monthly variability factors were based on 4-day monthly averages because EPA assumed the monitoring frequency to be weekly (approximately four times a month). The plant-specific monthly variability factor for each plant is the ratio of a 95th percentile to the long term average. In this case, the percentile we seek is the 95th percentile of the distribution of $\overline{U}_4$, which represents the average of four samples for a given plant. The monthly variability factor is calculated as follows:

$$VF4 = \frac{\hat{P}_{95}}{\hat{E}(U)} = \frac{\hat{P}_{95}}{LTA} \quad (27)$$

Below a description is given of how the 95th percentile is estimated under the assumption that $\overline{U}_4$ has a modified delta-lognormal distribution. The following steps also show how multiple detection limits (for non-detected values) were accounted for when estimating the 95th percentile of the monthly average.

In order to calculate the 4-day variability factor (VF4), the assumption was made that the approximating distribution of $\overline{U}_4$, the sample mean for a random sample of four independent concentrations, was also derived from the modified delta-lognormal distribution. To obtain the expected value of the mean of the four daily values, equation 20 is modified to indicate that it applies to the average:

$$\hat{E}(\overline{U}_4) = \hat{\delta}_4\left(\hat{E}(\overline{X}_4)_D\right) + \left(1 - \hat{\delta}_4\right)\hat{E}(\overline{X}_4)_C \quad (28)$$

where $\left(\overline{X}_4\right)_D$ denotes the mean of the discrete portion of the distribution of the average of four independent concentrations, (i.e., when all observations are non-detected) and $\left(\overline{X}_4\right)_C$ denotes the mean of the continuous lognormal portion (i.e., for averages involving detected observations).

First, it was assumed that the detection of each measurement is independent (the measurements were also assumed to be independent). Therefore, the probability of the detection of the measurements can be written as $\delta_4 = \delta^4$. Because the measurements are assumed to be independent, the following relationships hold:

$$\begin{gathered}\hat{E}(\bar{U}_4) = \hat{E}(U) \\ \hat{V}ar(\bar{U}_4) = \frac{\hat{V}ar(U)}{4} \\ \hat{E}((\bar{X}_4)_D) = \hat{E}(X_D) \\ \hat{V}ar((\bar{X}_4)_D) = \frac{\hat{V}ar(X_D)}{4}\end{gathered} \tag{29}$$

Substituting into equation 28 and solving for the expected value of the continuous portion of the distribution gives:

$$\hat{E}(\bar{X}_4)_C = \frac{\hat{E}(U) - \hat{\delta}^4\hat{E}(X_D)}{1-\hat{\delta}^4} \tag{30}$$

Using the relationship in equation 21 for the averages of 4 daily values, substituting terms from equation 29, and solving for the variance of the continuous portion of $\bar{U}_4$ gives:

$$\hat{V}ar(\bar{X}_4)_C = \frac{\frac{\hat{V}ar(U)}{4} + \left(\hat{E}(U)\right)^2 - \hat{\delta}^4\left(\frac{\hat{V}ar(X_D)}{4} + \left(\hat{E}(X_D)\right)^2\right)}{1-\hat{\delta}^4} - \left(\hat{E}(\bar{X}_4)_C\right)^2 \tag{31}$$

Using equations 18 and 19 and solving for the parameters of the lognormal distribution describing the distribution of $\left(\bar{X}_4\right)_C$ gives:

$$\begin{gathered}\hat{\sigma}_4^2 = ln\left(\frac{\hat{V}ar(\bar{X}_4)_C}{\left(\hat{E}(\bar{X}_4)_C\right)^2} + 1\right) \\ \hat{\mu}_4 = ln\left(\hat{E}(\bar{X}_4)_C\right) - \frac{\hat{\sigma}_4^2}{2}\end{gathered} \tag{32}$$

The non-detects can generate an average that is not necessarily equal to any of the D_1, D_2,...,D_k. Consequently, more than k discrete points exist in the distribution of the 4-day averages. For example, the average of four non-detects when there are k=2 distinct detection limits are at the following discrete k^* points with the associated probabilities denoted by δ_i^*, i=1,…, k^*:

i	**Value of $\overline{U}_4$ (D_i^*)**	**Probability of Occurrence (δ_i^*)**
1	D_1	δ_1^4
2	$(3D_1 + D_2)/4$	$4\delta_1^3\delta_2$
3	$(2D_1 + 2D_2)/4$	$6\delta_1^2\delta_2^2$
4	$(D_1 + 3D_2)/4$	$4\delta_1\delta_2^3$
5 (=k^*)	D_2	δ_2^4

When all four observations are non-detected values, and when *k* distinct non-detected values exist, the multinomial distribution can be used to determine associated probabilities. That is,

$$Pr\left(\overline{U}_4 = \frac{\sum_{i=1}^{k} u_i D_i}{4}\right) = \frac{4!}{u_1!\,u_2!\cdots u_k!}\prod_{i=1}^{k}\delta_i^{u_i} \tag{33}$$

where u_i is the number of non-detected measurements at the detection limit D_i. The number k^* of possible discrete averages for k=1,…,5, are as follows:

K	*k**
1	1
2	5
3	15
4	35
5	70

The remaining approach to estimating P_{95} is similar to the approach used to estimate P_{99} in the calculation of one-day variability factors, as described above. For m = 1, …, k^*, let

$$\hat{q}_m = \sum_{i=1}^{m}\hat{\delta}_i^* + \left(1-\hat{\delta}^4\right)\Phi\left(\frac{ln(D_m^*) - \hat{\mu}_4}{\hat{\sigma}_4}\right) \tag{34}$$

where $\Phi(\cdot)$ is the cumulative distribution function of the standard normal distribution.

Now, if all *k* values of $\hat{q}_m$ defined above are less than 0.95, then the 95th percentile is defined as:

$$\hat{P}_{95} = exp\left(\hat{\mu}_4 + \hat{\sigma}_4 \cdot \Phi^{-1}\left(\frac{0.95 - \hat{\delta}^4}{1 - \hat{\delta}^4}\right)\right) \tag{35}$$

where $\Phi^{-1}(p)$ is the p^{th} percentile of the standard normal distribution. Otherwise, let D_j^* denote the smallest of the k^* values of D_i^* for which $\hat{q}_j \geq 0.95$, and let $\hat{q}* = \hat{q}_j - \hat{\delta}_j^*$. Then, the 95th percentile is defined by the following:

$$\hat{P}_{95} = \begin{cases} D_j^* & if\ \hat{q}^* < 0.95 \\ exp\left(\hat{\mu}_4 + \hat{\sigma}_4 \cdot \Phi^{-1}\left(\frac{0.95 - \sum_{i=1}^{j-1} \hat{\delta}_i^*}{1 - \hat{\delta}^4}\right)\right) & if\ \hat{q}^* \geq 0.95 \end{cases} \tag{36}$$

B.6 Estimation of Plant-Specific Long-Term Averages and Variability Factors Assuming Autocorrelation

Section B.5 above described the procedure used to estimate the long-term averages and variability factors assuming no autocorrelation existed in the data. The subsections below describe how the plant specific long-term averages and variability factors are estimated assuming the autocorrelation exists in the data. Autocorrelation in the successive measurements affects the variance of the observed data. Therefore, if autocorrelation is deemed present in the data, then it should be accounted for when calculating the long term average and variability factors.

When the concentrations have autocorrelation, EPA substitutes the detection limit for the non-detects and assumes that all resulting values are detected and have a lognormal distribution. Since all measurements are treated as detects, δ=0 and the equations for the continuous portion of the delta-lognormal distribution can be adapted to describe all the data.

B.6.1 Estimation of Plant-Specific Long-Term Averages (LTA)

If a dataset for a pollutant at a plant meets the requirements described in Section B.5.1, then the plant specific long-term average (LTA) is calculated as follows:

$$LTA = exp(\hat{\mu}_{all} + 0.5\hat{\sigma}_A^2) \tag{37}$$

The parameter estimates $\hat{\mu}_{all}$ and $\hat{\sigma}_A^2$ are obtained using all n measurements as follows:

$$\hat{\mu}_{all} = \sum_{i=1}^{n} \frac{ln(x_i)}{n} \tag{38}$$

$$\hat{\sigma}_A^2 = \frac{1}{g(R)} \sum_{i=1}^{n} \frac{(ln(x_i) - \hat{\mu}_{all})^2}{n-1} \tag{39}$$

where x_i is the i^{th} measurement value, n is the total number of measurements (including both detected and non-detected values), and $g(R)$ is the adjustment for autocorrelation. For an AR(1) model with a 1-day lag correlation of ρ_1 and n daily values, the correlation (in the log scale) between x_i and x_j ($i \neq j$) is $Corr(ln(x_i), ln(x_j)) = \rho_1^{|i-j|}$. Then the adjustment for the autocorrelation is

$$g(R) = 1 - \frac{\sum_{i \in T} \sum_{j \in T, j \neq i} \rho_1^{|i-j|}}{n(n-1)} \tag{40}$$

where T = {1,...,n} is the set of days with observed daily values. For an AR(1) model with n sequential daily values, this reduces to

$$g(R) = 1 - \left(\frac{2}{n(n-1)}\right)\left(\frac{\rho_1}{1-\rho_1}\right)\left((n-1) - \frac{\rho_1(1-{\rho_1}^{n-1})}{1-\rho_1}\right) \tag{41}$$

since

$$\sum_{i \in T} \sum_{\substack{j \in T, \\ j \neq i}} \rho_1^{|i-j|} = 2\left(\frac{\rho_1}{1-\rho_1}\right)\left((n-1) - \frac{\rho_1(1-{\rho_1}^{n-1})}{1-\rho_1}\right)$$

where ρ_1 is the correlation of the log-transformed measurements from successive sampling events. Note that if the daily values are independent (i.e., autocorrelation is not present in the data), then $g(R)$ = 1.

B.6.2 Estimation of Plant-Specific Daily Variability Factors (VF1)

The plant-specific daily variability factor is the ratio of the 99th percentile to the long-term average and is calculated by

$$VF1 = \frac{\hat{P}_{99}}{\hat{E}(U)} = \frac{\hat{P}_{99}}{LTA} \tag{42}$$

The 99th percentile $\hat{P}_{99}$ in equation 42 is calculated as

$$\hat{P}_{99} = exp(\hat{\mu}_{all} + 2.326\, \hat{\sigma}_A) \tag{43}$$

where 2.326 is the 99th percentile of the standard normal distribution.

B.6.3 Estimation of Plant-Specific Monthly Variability Factors (VF4)

Plant-specific monthly variability factors were based on 4-day monthly averages because EPA assumed the monitoring frequency to be weekly (approximately four times a month). The plant-specific monthly variability factor for each plant is the ratio of a 95th percentile to the long-term average. In this case, the percentile we seek is the 95th percentile of the distribution of $\overline{U}_4$, which represents the average of four samples for a given plant.

Assuming the data follow a lognormal distribution, the monthly variability factor is calculated as:

$$VF4 = \frac{\widehat{P}_{95}}{\widehat{E}(U)} = \frac{exp\left(\hat{\mu}_4 + \hat{\sigma}_4 \Phi^{-1}(0.95)\right)}{LTA} \tag{44}$$

where

$$\hat{\sigma}_4^2 = ln\left(\frac{\hat{V}ar(\overline{U}_4)_C}{\left(\hat{E}(\overline{U}_4)_C\right)^2} + 1\right)$$
$$\hat{\mu}_4 = ln\left(\hat{E}(\overline{U}_4)_C\right) - \frac{\hat{\sigma}_4^2}{2} \tag{45}$$

The variance of the average represented by $\hat{V}ar\left(\overline{U}_4\right)$ is

$$\hat{V}ar(\overline{U}_4) = \frac{\hat{V}ar(U)}{4}\left(1 + f_4(R)\right) \tag{46}$$

where the factor $f_4(R)$ is used to adjust for the autocorrelation among the four values in the average. This adjustment factor is found by

$$f_4(R) = \frac{2}{4}\sum_{k=1}^{3}(4-k)\left(\frac{exp\left(\rho_1^{7k}\hat{\sigma}_A^2\right) - 1}{exp(\hat{\sigma}_A^2) - 1}\right) \tag{47}$$

B.7 Evaluation of Plant-Specific Variability Factors

The parameter estimates for the lognormal portion of the distribution can be calculated with as few as two distinct measured values in a dataset (in order to calculate the variance); however, these estimates can be imprecise (as can estimates from larger datasets). As stated in Section B.5.1 above, EPA developed plant-specific variability factors for datasets that had three or more observations with two or more distinct measured concentration values.

To identify situations producing unexpected results, EPA reviewed all of the variability factors and compared daily to monthly variability factors. EPA used several criteria to determine if the plant-specific daily and monthly variability factors should be included in calculating the option variability factors (the option variability factors refer to the technology option variability factor for a pollutant rather than regulatory option). One criterion that EPA used was that the daily and monthly variability factors should be greater than 1.0. A variability factor less than 1.0 would result in an unexpected result where the estimated 99th percentile would be less than the long-term average. This would be an indication that the estimate of σ (the standard deviation in log scale) was particularly large and most likely imprecise. A second criterion was that not all of the sample-specific detection limits could exceed the detected values. All plant-specific variability factors used for the limitations and standards met both the first and second criteria. A third criterion was that the daily variability factor had to be greater than the monthly variability factor. When this criterion was not met, the daily and monthly variability factors were excluded.

B.8 References

1. Aitchison, J. and J.A.C. Brown. 1963. *The Lognormal Distribution.* Cambridge University Press, New York.
2. Barakat, R. 1976. “Sums of Independent Lognormally Distributed Random Variables.” *Journal Optical Society of America*, 66**:** 211-216.
3. Cohen, A. C. 1976. “Progressively Censored Sampling in the Three Parameter Log-Normal Distribution.” *Technometrics*, 18:99-103.
4. Crow, E.L. and K. Shimizu. 1988. *Lognormal Distributions: Theory and Applications*. Marcel Dekker, Inc., New York.
5. Kahn, H.D., and M.B. Rubin. 1989. "Use of Statistical Methods in Industrial Water Pollution Control Regulations in the United States." *Environmental Monitoring and Assessment.* Vol. 12:129-148.
6. Owen, W.J. and T.A. DeRouen. 1980. “Estimation of the Mean for Lognormal Data Containing Zeroes and Left-Censored Values, with Applications to the Measurement of Worker Exposure to Air Contaminants.” *Biometrics*, 36:707-719.