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FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

PATRICIA Q. WEST

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 130007-EI

AUGUST 30, 2013

Q. Please state your name and business address.

A. My name is Patricia Q. West. My business address is 299 1st Avenue North, St. Petersburg, Florida, 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 130007-EI?

A: Yes, I provided direct testimony on April 1, 2013 and August 1, 2013.

Q: Has your job description, education, background or professional experience changed since that time?

A: No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide estimates of the costs that will be incurred in the year 2014 for Duke Energy Florida's (DEF or Company) Pipeline Integrity Management (PIM) Program (Project 3), Above Ground

Storage Tank Program (Project 4), Phase II Cooling Water Intake (Project 6), CAIR/CAMR Continuous Mercury Monitoring System (CMMS) (Projects 7.2 & 7.3), Best Available Retrofit Technology (BART) Program (Project 7.5), Arsenic Groundwater Standard (Project 8), Underground Storage Tanks (Project 10), Modular Cooling Towers (Project 11), Thermal Discharge Permanent Cooling Tower Project (Project 11.1), Greenhouse Gas Inventory and Reporting (Project 12), Mercury TMDL (Project 13), Hazardous Air Pollutants (HAPs) ICR Program (Project 14), Effluent Limitation Guidelines Information Collection Request (ICR) Program (Project 15), National Pollutant Discharge Elimination System (NPDES) Program (Project 16), and Mercury & Air Toxics Standards (MATS) Program – Crystal River Units 4 & 5 (CR4&5) (Project 17).

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. ___ (PQW-2), which is a copy of the U.S. Environmental Protection Agency's proposed revised effluent limitation guidelines and standards for the steam electric generating industry. I am also co-sponsoring the following portions of Exhibit No. __(TGF-5) to Thomas G Foster's direct testimony:

- 42-5P page 3 of 21 - Pipeline Integrity Management.
- 42-5P page 4 of 21 - Above Ground Storage Tank Containment.
- 42-5P page 6 of 21 - Phase II Cooling Water Intake.
- 42-5P page 7 of 21 – Clean Air Interstate Rule (CAIR).
- 42-5P page 8 of 21 – Best Available Retrofit Technology (BART).

- 42-5P page 9 of 21 - Arsenic Groundwater Standard.
- 42-5P page 11 of 21 - Underground Storage Tanks.
- 42-5P page 12 of 21 - Modular Cooling Towers.
- 42-5P page 13 of 21 - Crystal River Thermal Discharge Project.
- 42-5P page 14 of 21 - Greenhouse Gas Inventory and Reporting.
- 42-5P page 15 of 21 - Mercury TMDL.
- 42-5P page 16 of 21 - Hazardous Air Pollutants (HAPs) ICR Program.
- 42-5P page 17 of 21 - Effluent Limitation Guidelines ICR Program.
- 42-5P page 18 of 21 – National Pollutant Discharge Elimination System (NPDES).
- 42-5P page 19 of 21 – Mercury and Air Toxics Standards (MATS) Program – CR4&5.

Q. What costs does DEF expect to incur in 2014 in connection with the Pipeline Integrity Management Program (Project 3)?

A. DEF estimates O&M costs of approximately $370,000 for the PIM Program to comply with the PIM regulations (49 CFR Part 195). These costs include general program management and oversight of the performance of program activities.

Q. What costs does DEF expect to incur in 2014 in connection with the Above Ground Storage Tank Secondary Containment Program (Project 4)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Phase II Cooling Water Intake Program (Project 6)?

A. DEF estimates O&M costs of approximately $800,000 for the Phase II Cooling Water Intake Program to evaluate compliance with the 316(b) rule. As the Commission is aware, as a result of the July 17, 2012 second amendment to the settlement agreement among the U.S. Environmental Protection Agency (EPA) and plaintiffs, EPA was expected to issue a final rule establishing cooling water intake standards pursuant to Section 316(b) of the Clean Water Act rule in June 2013. As discussed in DEF's response to FPSC's Information Request dated May 19, 2011, the proposed rule would establish standards for impingement mortality that can be achieved in either one of two ways: 1) modify traveling intake screens with fish collection and return systems that demonstrate that 88% of the fish collected will survive the process or 2) reduce the intake flow velocity to 0.5 feet per second. The proposed 316(b) rules would establish that state permitting authorities (the Florida Department of Environmental Protection (FDEP) in Florida) determine requirements for entrainment mortality on a case-by-case, site specific basis. The permittee must collect data, conduct studies and submit information that would be used by the state permitting authorities to make its decision regarding compliance plans. DEF is assessing several options that may be required to comply with the rule. The options under consideration may change once the final rule is issued and its impacts better understood; therefore, the exact costs that DEF will incur under 316(b) cannot be predicted. On June 23, 2013, the EPA announced that it reached an agreement with

Riverkeeper to re-extend the deadline for issuing the 316(b) rule to November 4, 2013.

Q. What costs does DEF expect to incur in 2014 in connection with the CAIR / CAMR Program (Project 7.2)?

A. DEF estimates O&M costs of approximately $44,000 for the CAIR/CAMR Program for data acquisition system maintenance of combustion turbine units and 40 CFR 75, Appendix E, Section 2.2 air emissions compliance testing. This regulation requires the Company to perform air emissions testing to reset correlation curves every 20 quarters and must be performed on all of its Predictive Emissions Monitoring Systems (PEMS).

Q: What costs does DEF expect to incur in 2014 in connection with the Best Available Retrofit Technology (BART) Program (Project 7.5)?

A: DEF is currently evaluating potential software and hardware changes that may be necessary to enable data from the precipitators to be measured and recorded to fulfill requirements of the Compliance Assurance Monitoring Plan. If changes are determined to be necessary, DEF will likely to incur costs in late 2013 or early 2014.

Q. Please provide an update of the status of Florida Regional Haze State Implementation Plan (SIP).

A. As discussed in the update to DEF's Integrated Clean Air Compliance Plan submitted as Exhibit No. __ (PQW-1) to my April 1, 2013 testimony, FDEP submitted a revised Regional Haze SIP to EPA earlier this year. On August 14, 2013, EPA formally approved the revised SIP, with publication to follow in the *Federal Register*. As approved by EPA, the revised SIP reflects DEF's decision to cease coal-firing at CR1&2 by December 31, 2020. The revised SIP will become effective 30 days after publication of EPA's approval in the *Federal Register* and the deadline for seeking judicial review is 60 days after publication.

Q. What costs does DEF expect to incur in 2014 in connection with the Arsenic Groundwater Standard Program (Project 8)?

A. DEF estimates O&M costs of approximately $40,000 for the Arsenic Groundwater Standard Program to prepare and submit a parameter exemption petition to the FDEP, if required, once its groundwater plan of study (POS) is approved by the agency. The POS was submitted to the FDEP on April 26, 2013.

Q. What costs does DEF expect to incur in 2014 in connection with the Underground Storage Tanks Program (Project 10)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Modular Cooling Tower Program (Project 11)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Thermal Discharge Permanent Cooling Tower (Project 11.1)?

A. DEF does not expect any expenditures in 2014. As explained in Mr. Foster's direct testimony, DEF announced on February 5, 2013 that it will retire Crystal River Unit 3 (CR3). Due to the reduction in thermal loading resulting from the retirement of CR3, construction of the thermal discharge permanent cooling tower is no longer necessary.

Q. What costs does DEF expect to incur in 2014 in connection with the Greenhouse Gas (GHG) Inventory and Reporting Program (Project 12)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Mercury TMDL Program (Project 13)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Hazardous Air Pollutants (HAPs) Information Collection Request (ICR) Program (Project No. 14)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the Effluent Limitation Guidelines ICR Program (Project No. 15)?

A. DEF does not expect any expenditures in 2014.

Q. What costs does DEF expect to incur in 2014 in connection with the National Pollutant Discharge Elimination System (NPDES) Program (Project No. 16)?

A. DEF estimates O&M costs of approximately $477,000 of O&M costs for the NPDES Program to conduct studies including thermal evaluations and whole effluent toxicity testing (WET) at the Anclote, Bartow and Suwannee plants, and copper mixing zone study at the Suwannee plant. Capital expenditures in 2014 are expected to be approximately $1.2 million for completion of the Bartow freeboard project to comply with the FDEP NPDES permit.

Q. What costs does DEF expect to incur in 2014 in connection with the Mercury and Air Toxics Standards (MATS) Program – CR4&5 (Project No. 17)?

A. DEF estimates O&M costs of approximately $406,000 for CR4&5 MATS compliance: $36,000 for Appendix K mercury monitoring costs, $190,000 for mercury re-emission chemical costs, $100,000 for particulate matter (PM) continuous emissions monitors (CEMS) equipment installation costs and $80,000 for MATS Work Practice Standards costs. Capital expenditures are expected to be approximately $3.4 million: $3 million for mercury re-emission chemical and $400,000 for PM CEMS Installation.

Appendix K monitoring includes study equipment costs for mercury carbon traps used to capture baseline mercury emissions data on CR4&5. DEF will use the baseline data capture mercury speciation profiles to determine what, if any, mercury trim controls are necessary to meet MATS compliance. Potential options include brominated fuel additives and a flue gas desulfurization re-emission chemical.

The mercury re-emission chemical is an additive that suppresses mercury re-emission at CR4&5. On electric generating units equipped with wet scrubbers, re-emission may account for a portion of the total mercury emission. The extent of re-emission at CR4&5 will be assessed in the mercury speciation profile mentioned previously. The chemical would only be used on an as needed basis, primarily during unit start-up.

PM CEMS equipment installation costs are for continuous particulate matter measurement required for MATS compliance.

MATS Work Practice Standards costs include costs associated with combustion tuning activities that must be performed to comply with these standards.

Q. Is DEF requesting recovery of costs for any new environmental programs?

A. Yes. In April 2013, EPA proposed revised effluent limitation guidelines and standards (ELGs) for the Steam Electric Generating Industry pursuant to the federal Clean Water Act.   The new rule will establish new or additional requirements for wastewater streams from various processes and byproducts associated with steam electric power generation, including: flue gas desulfurization, fly ash, bottom ash, non-chemical metal cleaning wastes and flue gas mercury control. As explained in the *Federal Register* notice for the proposed rule, EPA is considering several options and has identified four preferred alternatives for regulation of discharges from existing sources. *See* 78 *Fed. Reg.* 34431-34543 (June 7, 2013) (Copy attached as Exhibit No. __(PQW-2)). These four proposed options differ in the number of waste streams covered, the size of the units controlled and the stringency of the controls that would be imposed.

Q. Has the Company projected the costs it will incur for the new program?

A. DEF is in the process of analyzing potential compliance options for affected units and expects to incur compliance costs in 2014. However, the full extent of compliance activities and associated expenditures cannot be determined at this time because the rule has not been finalized and because DEF has not had sufficient opportunity to analyze each of the four preferred alternatives. EPA is under a court-ordered mandate to adopt a final rule in May 2014.

Q. Do the costs for the new program qualify for recovery through the ECRC?

A. Yes. Costs for the new program meet the requirements for ECRC recovery previously established by the Commission. Specifically, the expenditures are being prudently incurred after April 13, 1993; the activities are legally required to comply with a governmentally imposed environmental requirement which was created, or whose effect was triggered, after the minimum filing requirements (MFRs) were submitted in PEF's last rate; and none of the costs of the new program are being recovered through base rates or any other cost recovery mechanism.

Q. Has the Commission previously approved recovery of costs for similar activities associated with development of environmental compliance measures?

A. In Order No. PSC-12-0613-FOF-EI issued on November 16, 2012, the Commission found that FPL's costs associated with the revised ELG rule are eligible for recovery through the ECRC.

Q. Does this conclude your testimony?

A. Yes.

FEDERAL REGISTER

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Part II

Environmental Protection Agency

40 CFR Part 423
Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule

34432 **Federal Register** / Vol. 78, No. 110 / Friday, June 7, 2013 / Proposed Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 423

[EPA–HQ–OW–2009–0819. FRL–9801–6; EPA–HQ–RCRA–2013–0209]

RIN 2040–AF14

Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing a regulation that would strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. Steam electric power plants alone contribute 50–60 percent of all toxic pollutants discharged to surface waters by all industrial categories currently regulated in the United States under the Clean Water Act. Furthermore, power plant discharges to surface waters are expected to increase as pollutants are increasingly captured by air pollution controls and transferred to wastewater discharges. This proposal, if implemented, would reduce the amount of toxic metals and other pollutants discharged to surface waters from power plants. EPA is considering several regulatory options in this rulemaking and has identified four preferred alternatives for regulation of discharges from existing sources. These four preferred alternatives differ with respect to the scope of requirements that would be applicable to existing discharges of pollutants found in two wastestreams generated at power plants. EPA estimates that the preferred options for this proposed rule would annually reduce pollutant discharges by 0.47 billion to 2.62 billion pounds, reduce water use by 50 billion to 103 billion gallons, cost $185 million to $954 million, and would be economically achievable.

DATES: Comments on this proposed rule must be received on or before August 6, 2013. EPA will conduct a public hearing on the proposed pretreatment standards on July 9, 2013 at 1:00 p.m. in the EPA East Building, Room 1153, 1201 Constitution Avenue NW., Washington, DC.

ADDRESSES: Submit your comments on the proposed rule, identified by Docket No. EPA–HQ–OW–2009–0819 by one of the following methods:

- *http:www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: OW-Docket@epa.gov*, Attention Docket ID No. EPA–HQ–OW–2009–0819.
- *Mail:* Water Docket, U.S. Environmental Protection Agency, Mail code: 4203M, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Attention Docket ID No. EPA–HQ–OW–2009–0819. Please include three copies.
- *Hand Delivery:* Water Docket, EPA Docket Center, EPA West Building Room 3334, 1301 Constitution Ave., NW., Washington, DC, Attention Docket ID No. EPA–HQ–OW–2009–0819. Such deliveries are only accepted during the Docket's normal hours of operation, and you should make special arrangements for deliveries of boxed information by calling 202–566–2426.

ADDRESSES: Submit any comments on the Coal Combustion Residuals Rule issues discussed in Section III.D of this **Federal Register** Notice, identified by Docket ID No. EPA–HQ–RCRA–2013–0209, by one of the following methods:

- *http:www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: RCRA-Docket@epa.gov*, Attention Docket ID No. EPA–HQ–RCRA–2013–0209. In contrast to EPA's electronic public docket, EPA's email system is not an ''anonymous access'' system. If you send an email comment directly to the Docket without going through EPA's electronic public docket, EPA's email system automatically captures your email address. Email addresses that are automatically captured by EPA's email system are included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.
- *Fax:* Comments on the CCR rule issue may be faxed to 202–566–0272; Attention Docket ID No. EPA–HQ–RCRA–2013–0209.
- *Mail:* Send your comments on the CCR rule issue to the Hazardous Waste Management System; Disposal Of Coal Combustion Residuals From Electric Utilities, Attention Docket ID No. EPA–HQ–RCRA–2013–0209, Environmental Protection Agency, Mailcode: 5305T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies.
- *Hand Delivery:* Deliver two copies of your comments on the CCR rule issue discussed in this **Federal Register** to the Hazardous Waste Management System; Disposal Of Coal Combustion Residuals From Electric Utilities: Notice, Attention Docket ID No. EPA–HQ–RCRA–2013–0209, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket No. EPA–HQ–OW–2009–0819. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or email. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA without going through *www.regulations.gov* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. A detailed record index, organized by subject, is available on EPA's Web site at *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm.* Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Water Docket in the EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is 202–566–1744, and the telephone number for the Water Docket is 202–566–2426.

Comments related to EPA's current thinking, as described in Section III.D, regarding how a final RCRA Coal Combustion Residuals rule might be aligned and structured to account for any final requirements adopted under the ELGs for the Steam Electric Power Generating point source category must be submitted to Docket ID Number Docket ID: EPA–HQ–RCRA–2013–0209.

Pretreatment Hearing Information: EPA will conduct a public hearing on the proposed pretreatment standards on July 9, 2013 at 1:00 p.m. in the EPA East Building, Room 1153, 1201 Constitution Avenue NW., Washington, DC. No registration is required for this public hearing. During the pretreatment hearing, the public will have an opportunity to provide oral comment to EPA on the proposed pretreatment standards. EPA will not address any issues raised during the hearing at that time but these comments will be included in the public record for the rule. For security reasons, we request that you bring photo identification with you to the meeting. Also, if you let us know in advance of your plans to attend, it will expedite the process of signing in. Seating will be provided on a first-come, first-served basis. Please note that parking is very limited in downtown Washington, and use of public transit is recommended. The EPA Headquarters complex is located near the Federal Triangle Metro station. Upon exiting the Metro station, walk east to 12th Street. On 12th Street, walk south to Constitution Avenue. At the corner, turn right onto Constitution Avenue and proceed to the EPA East Building entrance.

FOR FURTHER INFORMATION CONTACT: For technical information, contact Jezebele Alicea-Virella, Engineering and Analysis Division, Telephone: 202–566–1755; Email: *alicea.jezebele@epa.gov.* For economic information, contact James Covington, Engineering and Analysis Division, Telephone: 202–566–1034; Email: *covington.james@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities

Category	Example of regulated entity	North American industry classification system (NAICS) code
Industry	Electric Power Generation Facilities—Electric Power Generation	22111
	Electric Power Generation Facilities—Fossil Fuel Electric Power Generation	221112
	Electric Power Generation Facilities—Nuclear Electric Power Generation	221113

This section is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this proposed action. Other types of entities that do not meet the above criteria could also be regulated. To determine whether your facility would be regulated by this proposed action, you should carefully examine the applicability criteria listed in 40 CFR 423.10 and the definitions in 40 CFR 423.11 of the rule and detailed further in Section V—Scope/Applicability of the Proposed Rule, of this preamble. If you still have questions regarding the proposed applicability of this action to a particular entity, consult the person listed for technical information in the preceding **FOR FURTHER INFORMATION CONTACT** section.

How to Submit Comments

The public may submit comments in written or electronic form. (See the **ADDRESSES** section above.) Electronic comments must be identified by the Docket No. [EPA–HQ–OW–2009–0819] and must be submitted as a MS Word, WordPerfect, or ASCII text file, avoiding the use of special characters and any form of encryption. EPA requests that any graphics included in electronic comments also be provided in hard-copy form. EPA also will accept comments and data on disks in the aforementioned file formats. Electronic comments received on this notice may be filed online at many Federal Depository Libraries. No confidential business information (CBI) should be sent by email.

Supporting Documentation

The rule proposed today is supported by a number of documents including:

- Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD), Document No. EPA–821–R–13–002.
- Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Environmental Assessment), Document No. EPA–821–R–13–003.
- Benefits and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Document No. EPA–821–R–13–004.
- 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.

These documents are available in the public record for this rule and on EPA's Web site at *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm.*

Overview

This preamble describes the terms, acronyms, and abbreviations used in this notice; the background documents that support these proposed regulations; the legal authority for the proposed rule; a summary of the options considered for the proposal; background information; and the technical and economic methodologies used by the Agency to develop these proposed regulations. In addition, this preamble also solicits comment and data from the public. The following outline summarizes the organization of this document.

Table of Contents

I. Legal Authority

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

II. Executive Summary of the Proposed Rule

A. Purpose of the Regulatory Action

The steam electric power generating point source category (i.e., steam electric industry) consists of plants that generate electricity from a process utilizing fossil or nuclear fuel in conjunction with a thermal cycle employing the steam/water system as the thermodynamic medium. The proposed regulations would strengthen the controls on discharges from steam electric power plants by revising the technology-based effluent limitations guidelines and standards that apply to wastewater discharges to surface waters (i.e., direct discharges) and to publicly owned treatment works (i.e., indirect discharges to POTWs). The proposed requirements would reduce the amount of metals and other pollutants discharged to surface waters from power plants.

EPA is considering several options in this rulemaking and has identified four preferred alternatives for regulation of discharges from existing sources. These four preferred alternatives propose the same requirements for most wastestreams but, as described below in Section II.B., differ in the requirements that would be established for discharges associated with two wastestreams from existing sources. EPA also projects different levels of pollutant reduction and cost associated with these alternatives.

EPA estimates that the preferred regulatory options would reduce pollutant discharges by 0.47 billion to 2.62 billion pounds annually, and reduce water use by 50 billion to 103 billion gallons per year. EPA predicts substantial environmental and ecological improvements would result under the preferred regulatory options, along with reduced impacts to wildlife and human health.

The current regulations, which were last updated in 1982, do not adequately address the toxic pollutants discharged from the electric power industry, nor have they kept pace with process changes that have occurred 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), and flue gas mercury controls (FGMC)) have altered existing wastestreams or created new wastewater streams at many power plants.

As a result, each year the pollutant discharges from this industry are increasing in volume and total mass, and currently account for approximately 50–60 percent of all toxic pollutants discharged into surface waters by all industrial categories currently regulated under the CWA. See Section 3.2.2 of the Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Environmental Assessment)—EPA 821–R–13–003. The main pollutants of concern for these discharges include metals (e.g., mercury, arsenic, selenium), nitrogen, and total dissolved solids (TDS). As discussed in Section XIII and the Environmental Assessment report, there are numerous documented instances of environmental impact associated with these power plant discharges, such as harm to human health, harm to aquatic life, contamination of sediment, and detrimental impacts to wildlife. Water quality modeling, in addition to the documented damage cases, corroborates these impacts and indicates that the toxic discharges are a source of widespread aquatic-life impacts, and a source of increased cancer and non-cancer risks in humans, and toxic metal bioaccumulation in wildlife. These discharges also contribute large cumulative nutrient pollutant loads to sensitive watersheds, upsetting the natural balance of such waterbodies as the Great Lakes and the Chesapeake Bay.

This proposed rule would reduce current toxic and other pollutant discharges and their associated impacts. In general, depending on the option, the proposed rule would establish new or additional requirements for wastewaters associated with the following processes and byproducts: Flue gas desulfurization (FGD), fly ash, bottom ash, flue gas mercury control, combustion residual leachate from landfills and surface impoundments, nonchemical metal cleaning wastes, and gasification of fuels such as coal and petroleum coke. In addition to the proposed requirements, as part of this rulemaking EPA is considering establishing best management practices (BMP) requirements that would apply to surface impoundments containing coal combustion residuals (e.g., ash ponds, FGD ponds). EPA is also considering establishing 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).

The major provisions of the proposed rule are summarized below. In addition, the proposed requirements and the technologies that serve as the basis for these requirements are explained in more detail in Section VIII of this preamble.

B. Summary of Major Provisions of the Proposed Rule

Depending on the option, EPA is proposing to revise or establish Best Available Technology Economically Achievable (BAT), New Source Performance Standards (NSPS), Pretreatment Standards for Existing Sources (PSES) and Pretreatment Standards for New Sources (PSNS) that apply to discharges of pollutants found in the following wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate from landfills and surface impoundments, nonchemical metal cleaning wastes, and wastewater from flue gas mercury control (FGMC) systems and gasification systems.

EPA has identified four preferred alternatives for regulation of existing discharges in the proposed rule (and it has identified one preferred alternative for regulation of new sources). These four preferred alternatives are summarized below.

Discharges directly to surface water from existing facilities—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 in this proposal) 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 in this proposal), 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 3a requirements described above.

Under a third preferred alternative for BAT (referred to as Option 3 in this proposal), 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 in this proposal), 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 [3]) 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.

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:

- 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 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.

Additional details about the proposed effluent limitations and standards are described in Sections VIII and X of this preamble.

C. Summary of Costs and Benefits

Table II–1 summarizes the benefits [6] and social costs for the four preferred alternatives for this proposed rule, at 3 percent and 7 percent discount rates. Sections XI and XIV of this preamble provide additional information regarding the costs and the benefits for the proposed rule. Note that although Table II–1 includes the costs associated with BMPs being considered for the proposed rule, it does not similarly include the benefits associated with these BMPs. The BMPs under consideration for the ELGs would reduce the probability of impoundment failures and therefore would be expected to increase the benefits of the proposed ELGs. EPA intends to include such benefits in its analyses for the final rule, should EPA ultimately include the BMPs as part of the final ELGs.

It is important to note that although point estimates are provided in this table, the benefits estimates rely on complex models that include a variety of assumptions, each of which introduces considerable uncertainty into these estimates. This uncertainty is discussed in the Benefits and Cost Analysis for the Proposed Effluent

[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.

[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.

[6] EPA calculated benefits for some of the options considered for this proposal including Option 3 and Option 4. For others (3a, 3b, and 4a), EPA inferred the benefits based on the pollutant loading reductions (lbs.) relative to the pollutant loading reductions of Option 3 for which EPA analyzed and calculated benefits. See Section XIV for details.

Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—EPA 821–R–13–004 (BCA). EPA requests comment on the reasonableness of these assumptions, additional data that may be available to reduce uncertainties in these estimates, and approaches to characterize the remaining uncertainty.

TABLE II–1—TOTAL MONETIZED ANNUALIZED BENEFITS AND COSTS FOR THE PROPOSED RULE

[Millions; 2010$]

Preferred regulatory alternatives	Total monetized social benefits		Total social costs	
	3%	7%	3%	7%
Option 3a for Existing Sources; Option 4 for New Sources	[a] 139.4	[a] 104.8	$185.2	$164.5
Option 3b for Existing Sources; Option 4 for New Sources	[a] 205.5	[a] 153.0	281.4	257.2
Option 3 for Existing Sources; Option 4 for New Sources	$311.7	$230.4	572.0	545.3
Option 4a for Existing Sources; Option 4 for New Sources	[a] 482.5	[a] 424.8	954.1	914.7

[a] EPA did not estimate benefits for Options 3a, 3b and 4a. EPA inferred benefits for Options 3a, 3b, and 4a for illustrative purposes using elements of the more rigorous analysis done to estimate benefits for Options 3 and 4. See Section XIV for details.

III. Background

A. 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 different categories of point sources, such as industrial, commercial, and public 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 sections 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, oil and grease, 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) nonconventional pollutants, which are those pollutants that are not categorized as conventional or toxic (e.g., ammonia-N, phosphorus, and total dissolved solids).

B. Effluent Guidelines Program

EPA develops effluent guidelines that are technology-based regulations for a category of dischargers. EPA bases these regulations 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 plants 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 directly to surface waters), and two standards applicable to indirect dischargers (plants that discharge to POTWs), described in detail below.

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 nonconventional pollutants. In specifying BPT, EPA looks at a number of factors. EPA first considers the cost of achieving effluent reductions in relation to the effluent reduction benefits. The Agency also considers the age of equipment and facilities, the processes employed, engineering aspects of the control technologies, any required process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. 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.

2. Best Conventional Pollutant Control Technology (BCT)

The 1977 amendments to the CWA require 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, total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 FR 44501; 40 CFR 401.16).

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 on the basis of 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).

4. Best Available Demonstrated Control Technology (BADCT)/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, nonconventional, 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).

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).

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.

C. Steam Electric Effluent Guidelines Rulemaking History

EPA promulgated BPT, BAT, NSPS, and PSNS for the steam electric point source category on October 8, 1974 (39 FR 36186, as amended at 40 FR 7095, February 19, 1975; 40 FR 23987, June 4, 1975) (the ''1974 regulations''). The 1974 regulations controlled two basic kinds of discharges from power plants: (1) Thermal discharges (discharges of heat) and (2) pollutant discharges (e.g., discharges of chlorine, polychlorinated biphenyls (PCBs), and suspended solids). EPA promulgated non-thermal pollutant limitations applicable to discharges from the following wastestreams: Once-through cooling water, cooling tower blowdown, bottom ash transport water, fly ash transport water, boiler blowdown, metal cleaning wastes, low volume wastes, and material storage and construction site runoff (including coal pile runoff).

On July 16, 1976, the U.S. Court of Appeals for the Fourth Circuit remanded the following provisions of the 1974 regulations: (1) The thermal limitations, (2) the NSPS for fly ash transport water, (3) the rainfall runoff limitations for material storage and construction site runoff, and (4) the BPT variance clause. All other provisions of the regulations were upheld. *Appalachian Power* v. *Train,* 545 F.2d 1351, 1378 (4th Cir. 1976). EPA repromulgated the coal pile runoff regulations in 1980. 45 FR 37432 (June 3, 1980).

EPA promulgated PSES on March 23, 1977 (42 FR 15695) applicable only to indirect discharges of copper present in metal cleaning wastes and PCBs and oil and grease for all wastestreams.

On November 19, 1982, EPA revised and supplemented the effluent limitations guidelines and standards for BCT, BPT, BAT, BADCT/NSPS, PSES, and PSNS (47 FR 52290). Under the 1982 revisions, EPA reserved BCT limitations for all wastestreams and withdrew the BAT limitations for TSS and oil and grease from all wastestreams because those pollutants are properly regulated under BCT, instead of BAT. The rule also made revisions to the following effluent limitations guidelines and standards: BAT and NSPS for once-through cooling water; BAT, NSPS, PSES, and PSNS for cooling tower blowdown; NSPS and PSNS for fly ash transport water; NSPS for bottom ash transport water; and PSES and PSNS for chemical metal cleaning wastes. Finally, the rule revised the definition of low volume wastes to include boiler blowdown and withdrew the separate regulation for boiler blowdown.

D. Steam Electric Detailed Study

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 reviewing and revising 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. (See ''Steam Electric Power Generating Point Source Category: Final Detailed Study Report'' (EPA 821–R–09–008) at *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm)*

During the detailed study, EPA collected data about the industry in several ways. EPA conducted site visits and sampled wastewater at steam electric power plants, and EPA distributed a questionnaire to collect data from nine companies. EPA also reviewed numerous publicly available sources of data and coordinated with and solicited data from EPA program offices and other government organizations (e.g., state groups and permitting authorities), as well as industry, environmental groups, and other stakeholders.

As part of the detailed study, EPA evaluated a range of wastestreams and processes associated with the industry, but it ultimately focused largely on discharges associated with coal ash handling operations and wastewater from 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 identified several wastestreams that are relatively new to the industry (e.g., carbon capture wastewater), and wastestreams for which there was little characterization data at the time of the detailed study (e.g., gasification wastewater).

During the study, EPA found that the use of wet FGD systems (the kind of systems that generate discharges) to control sulfur dioxide (SO_2) air emissions has increased significantly since the last revision of the effluent guidelines in 1982. Moreover, based on industry announcements and modeling conducted for Clean Air Act rulemakings, the use of wet FGD systems is projected to continue to increase 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 treatment technologies are available to treat these pollutants in FGD wastewater; however, most plants use only surface impoundments (e.g., settling ponds) designed primarily to remove suspended solids from FGD wastewater.

EPA found that technologies that do not use water to transport ash are available for handling the fly ash (a combustion residual of fine ash particles entrained in the flue gases) generated at plants, and that such technologies do not generate nor discharge wastewater associated with handling fly ash (i.e., fly ash transport water). Most of these systems are operated at newer electric generating units because the current NSPS regulations, which were promulgated in 1982, prohibit the discharge of pollutants in fly ash transport water. Many older generating units have also converted to dry fly ash handling systems that use air (i.e., pneumatic systems that use air pressure and/or vacuum) to transport the fly ash to storage silos instead of using water to sluice the ash (i.e., pump as a mixture of water and ash) to surface impoundments. As a result, over 80 percent of existing plants use dry fly ash handling. For further information, see Section 4.3.1 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13–002.

Additionally, there are technologies available for handling the bottom ash (i.e., a combustion residual of heavier ash particles collected at the bottom of a boiler) that either do not use water to transport the bottom ash away from the boiler or that manage the transport water in a manner (i.e., closed-loop) that eliminates the need to discharge bottom ash transport water to surface water. Neither of these approaches discharge wastewater associated with transporting bottom ash. In fact, some of these technologies do not even generate bottom ash transport water. EPA estimates that by the time the final rule is promulgated, approximately 45 percent of plants will use dry bottom ash handling systems or will not discharge bottom ash transport water.

From information obtained during the detailed study, 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, selenium 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 to meet the current BPT limits for TSS and oil and grease. Based on the record, EPA found that there are technologies readily available to reduce or eliminate the discharge of pollutants contained in fly ash and bottom ash transport water.

Finally, the information obtained during the study indicates 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 combustion residues. EPA found 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), TDS, and nutrients. The primary routes by which combustion wastewater harms the environment are discharges or spills to surface waters, leaching to ground water, and by surface impoundments and constructed wetlands acting as attractive nuisances that increase wildlife exposure to the pollutants contained in the systems. The interaction of 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 data. Such wastestreams include FGD wastewater, 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. For further information, see Section 6 of the Steam Electric Power Generating Point Source Category: Detailed Study is available online at *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm.*

Based on the findings from the detailed study, which EPA issued in 2009, EPA began taking steps to revise the steam electric power generating effluent limitations guidelines and standards.

E. Clean Air Act (CAA) Rules

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 sulfur dioxide, 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 sulfur dioxide, NO_X and ozone-season NO_X addressed by the CSAPR react in the atmosphere to form $PM_{2.5}$ 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 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 carbon dioxide 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 carbon dioxide 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.

F. Cooling Water Intake Structures

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 that 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.

G. 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 CCRs and contaminated the Emory and Clinch rivers, emphasized the need for national standards to address risks associated with the disposal of CCRs.

1. Summary of Proposed CCR Rule

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, CCRs that are beneficially used would remain exempt under the Bevill exclusion.

EPA has not yet taken final action on the proposed CCR regulations. Certain aspects of the CCR rulemaking are discussed in this notice for purposes of better understanding the analyses underlying this proposed revisions to the steam electric generating ELGs. This notice is not proposing anything new or different with respect to the CCR rulemaking (on which the Agency has already solicited public comments) and, therefore, is not opening up that rulemaking to further public comments.

2. Intersection Between the Proposed ELG and Coal Combustion Residuals Rules

This section describes EPA's current thinking on how a final RCRA Coal Combustion Residuals (CCR) rule might be aligned and structured to account for any final requirements adopted under the ELGs for the Steam Electric Power Generating point source category. Consistent with RCRA section 1006(b), EPA seeks to effectively coordinate any final RCRA requirements with the ELG requirements, to minimize the overall complexity of these two regulatory structures, and facilitate implementation of engineering, financial and permitting activities. EPA's approach would also be consistent with Executive Order 13563, ''Improving Regulation and Regulatory Review,'' issued on January 18, 2011, which emphasizes that some ''sectors and industries face a significant number of regulatory requirements, some of which may be redundant, inconsistent, or overlapping,'' and it directs agencies to promote ''coordination, simplification, and harmonization.'' EPA's goal is to ensure that the two rules work together to effectively address the discharge of pollutants from steam electric generating facilities and the human health and environmental risks associated with the disposal of CCRs, without creating avoidable or unnecessary burdens.

In considering how to coordinate the potential requirements between the two rules, EPA is guided by the following policy considerations: first and foremost, EPA intends to ensure that its statutory responsibilities to restore and maintain water quality under the CWA and to protect human health and the environment under RCRA are fulfilled. At the same time, EPA would seek to minimize the potential for overlapping requirements to avoid imposing any unnecessary burdens on regulated entities and to facilitate implementation and minimize the overall complexity of the regulatory structure under which facilities must operate. Based on these considerations, EPA is exploring two primary means of integrating the two rules: (1) through coordinating the design of any final substantive CCR requirements regulatory requirements, and (2) through coordination of the timing and implementation of final rule requirements to provide facilities with a reasonable timeline for implementation that allows for coordinated planning and protects electricity reliability for consumers.

Coordination of CCR Substantive Requirements with ELG Requirements. EPA's current thinking is to focus primarily on the areas in which the proposed CCR and ELG rules may regulate or affect the same unit or activity. The scope of the two rules differs; although both of these rules would affect the disposal (*i.e.,* discharge) of coal combustion wastes to and from surface impoundments (*i.e.,* ''ponds'') at power plants, only the CCR rule would regulate the disposal of CCRs in landfills. Accordingly, in looking at how to coordinate the requirements of the two rules, EPA is primarily focusing on any requirements applicable to surface impoundments, rather than modifications to any requirements applicable to CCR landfills which would be addressed solely under any CCR rule.

One approach is to examine the ways in which EPA anticipates that facilities are likely to modify their operations to comply with the ELG rule, and factor the results of those assessments into EPA's evaluation of whether separate RCRA requirements under the CCR rule are needed to ensure protection of human health and the environment. For example, as described in greater detail in this preamble, the ELG rule could eliminate or reduce certain discharges to surface water, including by controlling or eliminating wastewater that is sent to and discharged from surface impoundments. While the ELG would not compel use of a particular technology, EPA predicts that one possible consequence of the proposed ELG requirements is that some number of facilities will choose to convert their sluicing operations to dry ash-handling systems, and will no longer send such wastes to surface impoundments. EPA is considering how these predictions might affect any specific technical requirements under RCRA that could be applicable to CCR surface impoundments. Thus, for instance, to the extent that facilities would no longer need to operate surface impoundments, it is possible that this might affect the time frames (or other requirements) necessary for closure of such impoundments.

However, it is also possible that the requirements established under a final ELG rule could affect the development of any final CCR rule more broadly. Since the close of the comment period on the CCR rule, EPA has received significant new data obtained from a 2010 Information Collection Request (ICR) conducted by EPA's Office of Water for the development of the ELG, which have the potential to affect the risk assessment for the CCR rule. This ICR gathered information from, among others, all 495 electric utility plants that operate coal-fired generating units. In the June 21, 2010 proposal, EPA did not have definitive data about the location, size, or age of the waste management units, nor on the type or composition of the wastes contained in surface impoundments. Consequently, the Agency relied on a 1995 industry report and a number of significant assumptions in the 2010 risk assessment supporting the proposed CCR rule.

These facility-specific data could be used in EPA's risk assessment for any CCR rule in several ways that could significantly affect the results of that assessment. For example, these data could be used to determine the extent to which plumes of contamination leaching from coal ash disposal units into groundwater are intercepted (and reduced) by surface water bodies that exist between a disposal unit and a down-gradient drinking water well. This information has the potential to significantly affect the nature and extent of the risks, and would allow EPA to better estimate the contaminant levels that people would be expected to receive in drinking water, and to better model the likely environmental risks (*e.g.,* to fish and other aquatic life) from such contaminants in surface waters. Because so many of the disposal units (both surface impoundments and landfills) are located next to rivers, the results of the interception analysis could reasonably be expected to have a significant impact on the risk assessment results.

In addition, these data provide information on the location, size, and the type of waste present in hundreds of surface impoundments that were omitted from the data sources on which EPA relied to develop the proposed CCR rule. These impoundments are generally, smaller than the impoundments included in the data used to support the proposed CCR rule, and can differ significantly from the impoundments located at larger facilities. Exclusion of these smaller impoundments could potentially bias the results of the risk assessment, because smaller surface impoundments contain less waste that would be subject to leaching, and any plumes of contamination would likely be smaller. Similarly, these data would allow EPA to refine its analysis of the potential risks from fugitive dust at landfills. Preliminary comparisons of the Office of Water data indicate that currently active portions of landfills are significantly smaller than the landfills identified in the 1995 survey that EPA used in its assessment of the risks from fugitive dust prepared for the proposed rule.

Although a final risk assessment for the CCR rule has not yet been completed, reliance on the data and analyses discussed above may have the potential to lower the CCR rule risk assessment results by as much as an order of magnitude. If this proves to be the case, EPA's current thinking is that, the revised risks, coupled with the ELG requirements that the Agency may promulgate, and the increased Federal oversight such requirements could achieve, could provide strong support for a conclusion that regulation of CCR disposal under RCRA Subtitle D would be adequate.

Coordination of Timelines for Implementation. The second component of EPA's approach to integrating any CCR rule with any ELG rule relates to the coordination of compliance and implementation deadlines. EPA's goal is that, consistent with its statutory requirements, the implementation dates for each rule would not require facilities to make decisions without understanding the implications that such decisions would have for meeting any requirements of each rule. Thus, EPA's current approach is to enable a facility to determine whether any changes to its operations are needed to comply with the Steam Electric ELG—and if so, what those might be—before the facility would be required, for example, to decide whether to close or retrofit any surface impoundments pursuant to any CCR rule. For example, assuming that an electric utility relied on a series of surface impoundments or ponds to dispose of wastewater generated at the plant, EPA's current approach would enable the facility—prior to the deadline by which the facility would need to decide whether to retrofit or close those surface impoundments to comply with any CCR rule—to effectively evaluate whether it makes business sense to continue to operate those ponds (with or without any modifications) in light of the requirements of both rules, or whether other changes to facility operations would be more cost-effective.

As it has in this proposed ELG rule, EPA also intends to consider, to the extent permitted by statute, any practical constraints facilities may face in implementing any requirements under both rules (See, for example, Section XVI, addressing implementation issues for the Steam Electric ELGs).

Comments on EPA's current thinking described above on how any final CCR rule might be aligned and structured to account for any final requirements adopted under the ELGs for the Steam Electric Power Generating point source category should be directed to Docket ID Number: EPA–HQ–RCRA–2013–0209. Any comments submitted on this limited set of issues will be considered as part of the CCR rulemaking. By contrast, comments submitted on any other issue related to the CCR rule will be considered ''late comments'' and EPA will not respond to such comments, nor will they be considered part of the CCR rulemaking record.

IV. Summary of Data Collection Activities

A. Questionnaire for the Steam Electric Power Generating Effluent Guidelines

A principal source of information used in developing this proposal is the industry responses to a survey, the Questionnaire for the Steam Electric Power Generating Effluent Guidelines, distributed by EPA under the authority of section 308 of the 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 Agency consulted with the major industry trade associations to ensure that the industry survey would be useful and to ensure an accurate list of potential recipients. In June 2010, EPA mailed the survey to 733 plants. In general, plants were required to provide responses for the 2009 calendar year. The following describes the questionnaire, the recipient selection process, and the review of the questionnaire responses.

1. Description of the Industry Survey Components

To obtain information relevant to the rulemaking, EPA's survey consisted of 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; and
- 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, an inventory of ponds/impoundments and landfills used for combustion residues (including coal, petroleum coke, and oil residues), coal storage and processing, and outfall information. 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. The process operation sections (Parts B, C, and E) included detailed questions about the types of processes employed, dates that certain types of equipment were installed or plans for future equipment installations, chemical usage, operating characteristics, wastewater generation, pollution prevention activities, and wastewater discharge information.

In Part D of the industry survey, EPA requested detailed information (including diagrams) on the wastewater treatment systems (including chemical usage), discharge flow rates, and operating and maintenance cost data (including chemical usage) (Part D). The ponds/impoundments and landfill questions (Parts F and G) requested information on the size, characteristics, and operation of the ponds/impoundments and landfills located at the facilities. These sections also obtained information on the leachate collection and treatment, and required facilities to collect and analyze samples of untreated and treated leachate from the ponds/impoundments and landfills that receive combustion residues. The survey respondents were required to provide the laboratory analytical results and additional descriptive information about the leachate samples.

For nuclear-fueled generating units, Part H of the industry survey requested general information on the operation of the nuclear units, the wastewaters generated, and the treatment of those wastewaters.

The financial and economic questions (Part I) requested information on the facilities' ownership structure and financial conditions.

The Agency used these data to evaluate process operations and wastewater generation, identify treatment technologies in place, and determine the feasibility of regulatory options for each plant. EPA identified and evaluated the treatment technologies available for treating FGD wastewater and leachate from surface impoundments and landfills, and approaches for ash handling that reduced or eliminated the use of water. EPA also used these data to estimate which plants may incur compliance costs and pollutant removals associated with the various technology control options.

EPA used survey data, along with additional data collected from public sources, to estimate economic impacts on facilities and owning entities under the eight main regulatory options EPA considered for this proposal.

2. Identification of Potential Questionnaire Recipients

The Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE), collects information on existing electric generating plants and associated equipment to evaluate the current status and potential trends in the industry. EPA used the information available from the 2007 Electric Generator Report (Form EIA–860), and supplemented it with information found in Form EIA–923 and a survey conducted by EPA's Office of Solid Waste and Emergency Response (OSWER), to create a listing of plants that have steam electric power generating activities believed to be subject to the existing Steam Electric Power Generating Effluent Guidelines.

EPA used the EIA data, which contains information on the location of each of the plants (e.g., address, city, state), to create an initial draft of potential questionnaire recipients that EPA shared with industry stakeholders (e.g., the Utility Water Act Group (UWAG)) and interested environmental organizations. UWAG distributed the list to its members and provided feedback to the Agency to correct inaccurate addresses as well as identify plants that were not included or plants that are no longer in operation. Based on the original EIA data and industry feedback, EPA identified 1,197 steam electric generating plants for the survey sample frame (i.e., a list of all steam electric power plants from which the surveyed plants would be selected).

3. Questionnaire Recipient Selection

As a first step in selecting questionnaire recipients, EPA grouped all identified steam electric power plants based on the types of fuels burned at the facility. EPA first classified the generating units into fuel groups based on the primary and secondary energy sources reported in the 2007 Form EIA–860. EPA used the following hierarchy to classify the generating units: Coal, petroleum coke, gas, oil, and nuclear. Generating units that identified either coal or petroleum coke as the primary or secondary energy source were classified as a coal or petroleum coke generating unit. For generating units that did not identify coal or petroleum coke as a primary or secondary energy source, EPA used the primary energy source to classify the generating unit as gas, oil or nuclear. Based on the generating unit classifications, EPA then grouped plants into the fuel categories based on the following hierarchy: Coal, petroleum coke, combination, gas, oil, nuclear. For example, if a plant has one coal unit and five gas units, EPA identified the plant as a coal plant. 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.

Because much of the focus of this proposed rule is on the FGD and ash wastewaters, which are primarily generated at coal- and petroleum coke-fired plants, EPA sent questionnaires to all plants that operate coal- or petroleum coke-fired generating units. For plants without any coal- or petroleum coke-fired generating units (i.e., gas, oil, or nuclear-fueled), EPA sent questionnaires to a statistically selected subset of the identified plants. EPA created four different versions of the questionnaire to send out to plants based on the different parts of the questionnaire:

- Version 1: Parts A through I;
- Version 2: Parts A, B, C, D, H, and I;
- Version 3: Parts A, B, C, D, E, H, and I; and
- Version 4: Parts A, E, H, and I.

In June 2010, EPA mailed the surveys to 733 power plants. EPA mailed Version 1 of the questionnaire to 97 coal- and petroleum coke-fired power plants, which is a subset of the total number of coal- and petroleum coke-fired power plants. EPA mailed Version 2 of the questionnaire to the remaining 407 coal- and petroleum coke-fired power plants. EPA mailed Version 3 of the questionnaire to 20 oil-fired plants and 22 plants that burn at least two different types of fuel (e.g., combination plants). EPA mailed Version 4 of the questionnaire to 187 gas-fired and nuclear power plants.

4. Questionnaire Responses

EPA received completed surveys from all 733 questionnaire recipients. A total of 53 plants 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.

5. Questionnaire Review

EPA reviewed the surveys for completeness and consistency, using checklists for the review process to help identify potential issues with responses (e.g., data reported in incorrect units, missing responses). After completing the review for each plant, EPA contacted the plant to review the potential issues identified during the review process, if needed. EPA then created a database that contains all survey responses. The questionnaire database in the public record includes all information submitted for which facilities have not asserted that the information is confidential business information (CBI). In some instances, EPA has redacted non-CBI data to prevent the disclosure of other data claimed as CBI.

B. Engineering Site Visits

EPA conducted 68 site visits to power plants in 22 states and Italy between December 2006 and February 2013 to collect information about plant operations, process wastewater generation and management practices, and wastewater treatment systems. The primary purpose of these site visits was to evaluate candidate best available technologies and best available demonstrated control technologies, the changes necessary to implement new processes or technologies, and evaluate plants for potential inclusion in EPA's field sampling program. EPA used information provided by UWAG, responses from the detailed study data request, industry survey data, and information learned from contacts with industry representatives to identify site visit candidates. EPA based site visit selection on the type of operations at the plant (e.g., wet FGD systems, wet fly ash or bottom ash handling, gasification), and the plant's approach for minimizing pollutant discharges associated with these operations (e.g., sites employing candidate best available technologies, best available demonstrated control technologies, or processes that reduce or eliminate pollutant discharges.)

EPA collected detailed information from the plants visited, such as the operations associated with wastewater generation, in-process treatment and recycling systems, end-of-pipe treatment technologies, and, if the plant was a candidate for sampling, the logistics of collecting samples. EPA also obtained information regarding zero discharge options associated with the various operations and how the plants could potentially achieve zero discharge for some or all of these operations. EPA prepared site visit reports summarizing the collected information. EPA has included in the public record site visit reports that contain all information collected during site visits for which the plants have not asserted a claim of CBI.

C. 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 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 conducted on-site sampling (i.e., the Agency collected the samples) at 13 of the 17 power plants. Using its authority under CWA section 308, EPA directed seven of these EPA-sampled plants and four additional plants not sampled by EPA to collect additional samples, which were sent to EPA-contracted laboratories for analysis (i.e., CWA 308 monitoring program). In general, EPA used the following criteria to identify the plants included in the sampling program:

• The plant performs steam electric power generation activities representative of steam electric power plants (i.e., the plant's operations are typical of operations observed at other power plants, and therefore, are representative of more than just itself);

• The plant uses coal and/or petroleum coke (the wastestreams of interest and pollutants of concern identified in this rulemaking are primarily associated with plants using these types of fuels); and

• The plant has the wastestreams or treatment technologies of interest.

EPA also obtained sampling data for surface impoundment and landfill leachate collection and treatment systems at 39 plants, as directed by Part G of the Questionnaire for the Steam Electric Power Generating Effluent Guidelines. This leachate sampling is not included in the following description of the field sampling program. See Section 10.2.3 of the TDD for more information on leachate data collected under the industry survey.

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.

Upon completing the detailed study, EPA subsequently selected 13 plants to collect additional wastewater characterization data and to evaluate wastewater treatment performance. Through this effort, EPA evaluated 10 FGD wastewater treatment systems; two gasification systems at integrated gasification combined cycle (IGCC) plants; and one pilot-scale carbon capture system. EPA selected these FGD systems because at the time it believed all were among the better performing FGD wastewater treatment systems in the industry, based on information obtained during the site visits and discussions with industry representatives about the design/operation of the treatment system and optimization efforts performed at the plant. In addition, these plants represent geographic variability, different coal types (i.e., bituminous, subbituminous, coal blends), and different operating practices (e.g., baseload vs cycling). The selected IGCC systems and the pilot-scale carbon capture system were the only known systems operating in the U.S. power industry at the time of EPA's field sampling program.

For the 13 plants sampled following completion of the detailed study, samples were collected as follows:

• For seven plants, EPA collected performance data for four consecutive days and the plants also subsequently collected four sets of samples over a four to five month period;

• For four plants, the facility collected performance data for four consecutive days;

• For one plant, EPA collected performance data for three consecutive days; and

• For one plant, the facility collected performance data for one day.

EPA (or the plant) collected representative samples at the influent and effluent of the treatment system being evaluated using a combination of 24-hour composite and grab samples, depending on the sample location and the parameter to be analyzed. EPA analyzed the samples for up to 64 parameters, including conventional pollutants (e.g., TSS, BOD_5), nonconventional pollutants (e.g., TDS, nutrients), and metals. For samples collected by EPA, EPA quantified both the total amount of metal and the dissolved portion only. For samples collected by the plants, EPA quantified the total amount of metal. Prior to initiating sampling activities, regardless of who collected the samples, EPA developed sampling plans that detailed the procedures for sample collection, including the pollutants to be sampled, location of the sampling points, and sample collection, preservation, and shipment techniques.

Subsequent to the EPA and industry sampling efforts, EPA prepared a report summarizing the wastewater treatment processes, sampling procedures, and analytical results. EPA has included in the public record these reports containing all information collected for which a facility has not asserted a confidentiality claim or which would indirectly reveal information claimed to be CBI.

D. EPA and State Sources

EPA collected information from the Agency's databases and publications, states, and permitting authorities, including the following:

• Information on current and proposed permitting practices for the steam electric industry from a review of selected NPDES permits and accompanying fact sheets;

• Input from EPA and state permitting authorities regarding implementation of the existing Steam Electric Power Generating effluent guidelines;

• Background information on the steam electric industry from documents prepared during the development of the existing Steam Electric Power Generating effluent guidelines (i.e., the 1974 and 1982 rulemakings);

• Information from a survey of the industry conducted for the Cooling Water Intake Structures rulemaking;

• Information from EPA's Office of Air and Radiation (OAR), including Integrated Planning Model (IPM) projections based on recent air rules (i.e., CAIR/CSAPR rule and MATS);

• Information from EPA's Office of Research and Development (ORD) characterizing CCR 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 CCR under RCRA.

E. Industry Data

EPA obtained information on steam electric wastewaters and pollutants directly from the industry through self-monitoring data, as well as NPDES Form 2C data. Specifically, EPA requested self-monitoring data from two power plants to support its calculation of pollutant loading reductions from FGD wastewater treatment technologies and to supplement the data from the EPA sampling program in the development of ELGs for the FGD wastewater. EPA also coordinated with UWAG to create a database of selected NPDES Form 2C data from UWAG's member companies. The NPDES 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 and reviewed the data for use in developing the industry profile, in particular for ash wastewater treatment operations.

F. Technology Vendor Data

EPA gathered data from technology vendors through presentations, conferences, meetings, and email and phone contacts to gain information on the technologies used in the industry. EPA also used these contacts with vendors to obtain costs to install and operate the technologies considered as part of the proposed rule. These data informed the development of the industry survey, the technology costs, and the pollutant loadings estimates.

G. Other Sources

EPA obtained additional information on steam electric processes, technologies, wastewaters, pollutants, and regulations from sources including trade associations (e.g., UWAG), the Electric Power Research Institute (EPRI), DOE, the U.S. Geological Survey (USGS), and literature and Internet searches. EPA used information provided by the Environmental Integrity Project (EIP), Earthjustice, and the Sierra Club to document known environmental impacts caused by steam electric power plant discharges. In addition, EPA considered information provided in public comments during the effluent guidelines planning process, as well as other contacts with interested stakeholders.

H. Economic Data

To conduct cost and economic impact analysis of the proposed regulation, EPA used financial and operational data for steam electric power plants and their parent companies collected through the Steam Electric Questionnaire described in Section IV.A of this preamble.

EPA also used publicly available data describing current operating and business conditions at the steam electric power plants, operators, and parent companies, data describing economic/financial conditions in, and the regulatory environment of, the electric power industry, as well as data on electricity prices and electricity consumption. EPA obtained publicly available data from the following sources: the Department of Energy's EIA (in particular, the EIA 860, 861, and 906/920/923 databases),[7] the U.S. Small Business Administration (SBA), the Bureau of Labor Statistics (BLS), and the Bureau of Economic Analysis (BEA), Securities and Exchange Commission (SEC) Forms 10–K, companies' annual financial reports and press releases, newspapers articles, and Standard & Poor's. Finally, EPA relied on analysis and outputs from the Integrated Planning Model (IPM), a comprehensive electricity market optimization model that can evaluate impacts within the context of regional and national electricity markets (See Section XI).

V. Scope/Applicability of the Proposed Rule

A. Facilities Subject to 40 CFR Part 423

This proposal would establish new requirements for certain plants within the scope of the existing regulations for the steam electric power generating point source category. The proposed requirements would apply to discharges of wastewater associated with the following processes and byproducts: flue gas desulfurization, fly ash, bottom ash, combustion residual leachate, flue gas mercury control, nonchemical metal

[7] EIA–860: Annual Electric Generator Report; EIA–861: Annual Electric Power Industry Database; EIA–923: Utility, Non-Utility, and Combined Heat & Power Plant Database (monthly).

cleaning wastes, and gasification of fuels such as coal and petroleum coke. EPA is also considering establishing best management practices for surface impoundments receiving coal combustion residuals.

EPA is proposing to correct a typographical error in 40 CFR 423.17(d)(1) by adding a footnote that is missing from the table specifying PSNS for cooling tower blowdown. As is clear from the development document for the 1982 rulemaking, the footnote was intended to appear, as it does in the corresponding table for NSPS, and its omission was an inadvertent mistake, which EPA is now correcting. The footnote proposed to be added reads ''No detectable amount'' and refers to the effluent standard for 124 of the 126 priority pollutants contained in chemicals added for cooling tower maintenance. (See ''Development Document for Final Effluent Guidelines, New Source Performance Standards and Pretreatment Standards for the Steam Electric Power Generating Point Source Category,'' Document No. EPA 440/1–82/029. November 1982.)

In addition, EPA is proposing three modifications to the applicability provision for the ELGs. These are not substantive modifications and would not alter which generating units are regulated by the ELGs nor impose compliance costs on the industry. Instead, the proposed modifications would remove potential ambiguity present in the current regulatory text by revising the text to more clearly reflect EPA's long-standing interpretation.

First, the applicability provision in the current ELGs states, in part, that the ELGs apply to ''an establishment primarily engaged in the generation of electricity for distribution and sale. . . .'' 40 CFR 423.10. EPA is proposing to revise that phrase in the applicability provision to read ''an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation . . .'' This proposed modification would clarify that certain facilities, such as generating units owned and operated by industrial facilities in other sectors (e.g., petroleum refineries, pulp and paper mills) are not included within the scope of the steam electric ELGs. In addition, the proposed modification would clarify that 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 that are not commonly thought of as a ''sale'' are nevertheless subject to the ELGs. Such facilities have traditionally been regulated by the steam electric ELGs, and EPA believes the proposed modification will improve regulatory clarity.

Second, EPA is proposing a modification to the applicability provision to clarify that fuels derived from fossil fuel are within the scope of the current ELGs. The ELGs currently state, in part, that the ELGs apply to discharges related to the generation of electricity ''which results primarily from a process utilizing fossil-type fuels (coal, oil, or gas) or nuclear fuel . . .'' 40 CFR 423.10. Because there are a number of fuel types that are derived from fossil fuel, and which thus are fossil fuels themselves, EPA is proposing to revise that phrase in the applicability provision to read ''which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (e.g., petroleum coke, synthesis gas), or nuclear fuel . . .''

Third, EPA is proposing to amend the applicability provision to clarify that combined cycle systems are subject to the requirements of the ELGs. The ELGs apply to electric generation processes that utilize ''a thermal cycle employing the steam water system as the thermodynamic medium.'' 40 CFR 423.10. EPA's longstanding interpretation of this provision is that the ELGs apply to all electric generation processes with at least one prime mover that utilizes steam (if they also meet the other factors specified in Section 423.10, including the use of fossil or nuclear fuel). 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. The combustion turbines for a combined cycle system operate in tandem with the steam turbines; therefore, the ELGs apply to wastewater discharges associated with both the combustion turbine and steam turbine portions of the combined cycle system.

B. Subcategorization

The CWA requires EPA to consider a number of different factors when developing ELGs for a particular industry category (see BAT factors listed at 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 equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors the Administrator deems appropriate. One way EPA may take these factors into account 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. 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 questionnaires, site visits, sampling, and other data collection activities (see Section IV 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, as discussed further below.

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. It determined that the age of the plant by itself does not in general affect the wastewater characteristics, the processes in place, or the ability to install the treatment technologies evaluated as part of this rulemaking. Therefore, EPA did not establish subcategories based on the age of the plant or generating unit for this proposal.

2. Geographic Location

EPA analyzed the geographic location of power plants included in the scope of the rule. It 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 found 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 of the TDD. 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 would 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.

3. Size

EPA analyzed the size (i.e., nameplate generating capacity in MW) of the steam electric generating unit and determined that it can be 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. 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 VIII of this preamble discusses in greater detail EPA's proposal for applying different standards to certain existing units.

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 industry 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.

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.[8] 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 industry 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 VIII of this preamble discusses in greater detail EPA's proposal for applying different standards to certain existing oil-fired units.

VI. Industry Description

A. General Description of Industry

The steam electric power generating point source category (i.e., steam electric industry) consists of plants that generate electricity from a process utilizing fossil or nuclear fuel in conjunction with a thermal cycle employing the steam/water system as the thermodynamic medium. Based on responses to the industry survey, the Agency estimates that, excluding plants reporting that they would be retired by December 2011, and those plants reporting that they did not operate fossil- or nuclear-fueled units in 2009, there were 1,079 steam electric power plants operating in 2009. These facilities operate an estimated 2,195–2,230 generating units (including combined cycle systems), which have a total nameplate generating capacity of 741,000 MW. (Note: EPA has withheld the precise number of generating units to prevent disclosing CBI.) Table VI–1 shows the estimated number of steam electric generating units broken out by the five primary types of fuels used: coal, petroleum coke, oil, gas, and nuclear.

TABLE VI–1—ESTIMATED NUMBER OF STEAM ELECTRIC GENERATING UNITS AND CAPACITY BY PRIMARY FUEL SOURCE

Primary fuel source	Number of Generating units	Nameplate capacity (MW)
Coal	1,080–1,090	328,000–330,000
Petroleum Coke	12	1,000
Oil	75–100	23,900–25,400
Gas	929	282,000
Nuclear	99	104,000

[8] 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.

TABLE VI–1—ESTIMATED NUMBER OF STEAM ELECTRIC GENERATING UNITS AND CAPACITY BY PRIMARY FUEL SOURCE—Continued

Primary fuel source	Number of Generating units	Nameplate capacity (MW)
Total Industry	2,195–2,230	741,000

Source: Steam Electric Technical Questionnaire Database (DCN SE01958).

As seen from these data, most of the steam electric generating capacity (82 percent) is associated with either coal or gas. Based on survey responses, EPA also found that most plants in the industry have a generating capacity greater than 500 MW and may operate only one generating unit or multiple generating units. Plants of that size account for over 60 percent of all steam electric plants, 70 percent of all electric generating units, and 90 percent of the electric generating capacity.

For coal- and petroleum coke-fired plants, EPA determined that most plants (89 percent) are discharging at least some of their wastewater to surface waters or POTWs. Some plants operate without discharging certain wastewaters (e.g., fly ash transport water, FGD wastewater); however, most plants discharge at least their cooling water. Few of the discharging plants send wastestreams addressed by this rulemaking to POTWs. EPA identified approximately 10 coal- or petroleum coke-fired plants that discharge their FGD wastewater and/or fly ash or bottom ash transport water to POTWs. EPA also found that approximately 11 percent of coal- and petroleum coke-fired power plants do not discharge any wastewater. Most of these zero discharge plants are located in the southwestern United States (e.g., Arizona) and use evaporation ponds to control the wastewater.

B. Steam Electric Process Descriptions and Wastewater Generation

In the steam electric process, fuel is fed to a boiler where the fuel is combusted. The hot gases from combustion leave the boiler and pass through air pollution control systems prior to their emission through a stack. The resulting heat from combustion converts water to steam. 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 lower-pressure steam leaving the turbine enters the condenser, where steam vapor is cooled and condensed back into liquid by cooling water. The water collected in the condenser is sent back to the boiler where it is again converted to steam.

Combined cycle systems consist of combustion turbine electric generating units operating in conjunction with steam turbine electric generating units. Combustion turbines, which typically are similar to jet engines, commonly use natural gas as the fuel. Combined cycle systems feed the fuel into a chamber where it is combusted to generate heat. The combustion exhaust gases are sent directly through a combustion turbine to generate electricity. These exhaust gases still contain useful waste heat as they exit the combustion turbine, so they are directed to heat recovery steam generators to generate steam that is then used to drive a steam turbine, which operates as described above for the steam electric process. The operation of the steam turbine electric generating unit within a combined cycle system is virtually identical to a stand-alone steam electric generating unit, with the exception of the boiler.

IGCC is an electric power generation process that combines gasification technology with combined cycle systems. In an IGCC system, a gasifier converts carbon-based feedstocks (e.g., coal or petroleum coke) into a synthetic gas (syngas) using high temperature and pressure. The syngas is cleaned through multiple process operations and then combusted in a combustion turbine. As with a combined cycle system, a heat recovery steam generator extracts the heat from the exhaust gases to generate steam and drive a steam turbine.

Certain wastewaters generated at steam electric power plants differ based on the fuel used; however, almost all steam electric power plants generate some wastewaters. For example, because all steam electric power plants use a steam water system as the thermodynamic medium, all power plants use cooling water to condense the steam in the system. Additionally, most steam electric power plants have a boiler blowdown stream to purge salts from the water used in the steam water system. Other wastewaters are generated from the use of air pollution control systems and are more directly tied to the type of fuel burned. Coal- and petroleum coke-fired steam electric generating units, and to a lesser degree oil-fired units, generate a flue gas stream that contains large quantities of particulate matter, sulfur dioxide, and nitrogen oxides, which would be emitted to the atmosphere if they were not cleaned from the flue gas prior to emission. Therefore, many of these units are outfitted with air pollution control systems (e.g., particulate removal systems, flue gas desulfurization systems, and NO_X removal systems). Gas-fired units generate fewer emissions of particulate matter, sulfur dioxide, and nitrogen oxides than coal- or oil-fired units, and therefore do not typically operate air pollution control systems to control emissions from their flue gas. EPA determined that the wastewaters associated with these air pollution control systems contain large quantities of metals (e.g., arsenic, mercury, and selenium). Due to increased use of these air pollution control systems in the last decade, and an expected increase in the installation and use of air pollution controls over the next decade, EPA is focusing this rulemaking, in part, on controlling the discharges of these wastewaters.

The information in the remainder of Section VI below describing industry practices generally presents data collected by the industry survey and represents operational conditions for the year 2009. The industry survey represents the most complete source of data available to EPA regarding the operational conditions and wastewater management practices at steam electric power plants. In some cases, where appropriate and as specified below, EPA presents additional information characterizing significant changes to operational practices that have taken place since 2009.

1. Fly Ash and Bottom Ash Systems

Plants use particulate removal systems, which typically consist of either electrostatic precipitators (ESPs) or fabric filters, to collect fly ash and other particulates from the flue gas. The fly ash and other particulates are captured by the ESP or fabric filters and collected in hoppers located underneath the equipment. From the collection hoppers, the fly ash is either pneumatically transferred as dry ash to silos for temporary storage or transported (sluiced) with water to a surface impoundment (i.e., ash pond). The water used to transport the fly ash to the surface impoundment is usually discharged to surface water as overflow from the impoundment after the fly ash has settled. Of the coal- and petroleum coke-fired steam electric generating units that generate fly ash, 66 percent operate dry fly ash transport systems, while 15 percent operate both wet and dry fly ash transport systems. The remaining 19 percent operate only wet fly ash transport systems, although not all of these plants discharge their fly ash transport water. 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.

Fly ash transport water is one of the largest volume flows for coal-fired power plants. Many wet transport plants (i.e., 45 percent of plants with wet fly ash systems) sluice their fly ash continuously, and 68 percent of wet transport plants sluice their fly ash at least 12 hours per day. Based on responses to the industry survey, the average fly ash transport water flow rate is 2.4 million gallons per day (MGD). EPA estimates that the steam electric industry discharged a total of 81.1 billion gallons of fly ash transport water to surface water in 2009.

In addition to the particulate removal system for removing fly ash from the flue gas, there are also systems for handling the bottom ash that accumulates at the bottom of the furnace. The bottom ash consists of the heavier ash particles that could not be entrained in the flue gas and fall to the bottom of the furnace. In most furnaces, the hot bottom ash is quenched in a water-filled hopper. Ash from the hopper is then fed into a conveying line where it is diluted into slurry and pumped to an impoundment or dewatering bins. The ash sent to a dewatering bin is separated from the transport water and then disposed. For both of these systems, the water used to transport the bottom ash to the impoundment or dewatering bins is usually discharged to surface water as overflow from the systems, after the bottom ash has settled. Alternatively, some furnaces are fitted with mechanical drag systems where the bottom ash drops into a water-filled trough, but the ash is removed using a submerged mechanical drag conveyor that drags the bottom ash out of the furnace. At the end of the trough, the drag chain reaches an incline, which dewaters the bottom ash by gravity, draining the water back to the trough as the ash moves up the conveyor. The bottom ash is often dumped into a nearby bunker for temporary storage. As the bottom ash continues dewatering in the nearby bunker, water that drains from the system may be discharged; however, EPA does not consider this water from the bunker to be bottom ash transport water because the mechanical conveyor, and not the water, is the transport mechanism that moves the ash away from the boiler. Instead, the wastewater draining from the bunker would be low volume wastes. Over 65 percent of the units generating bottom ash operate wet bottom ash transport systems, approximately 30 percent operate systems that eliminate the use of transport water, and approximately 5 percent operate both. Plants that have both wet and dry handling operations typically use the wet handling system as a backup to the dry system. Some plants that have wet bottom ash systems operate them in a manner that does not discharge to surface 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 flows for steam electric plants. Based on responses to the industry survey, the average bottom ash transport water flow rate is 1.8 MGD. EPA estimates that the steam electric industry discharged a total of 157 billion gallons of bottom ash transport water in 2009.

Power plants that generate fly ash and bottom ash can either dispose of it in landfills or surface impoundments, or can use it in applications such as cement or concrete manufacturing. Power plants have used the ash in many applications that preclude the need to dispose of the ash in landfills/impoundments.

2. FGD Systems

FGD systems remove sulfur dioxide from the flue gas so that it is not emitted into the air. There are both wet and dry FGD systems. Dry FGD systems generally inject an aqueous sorbent (e.g., lime) into a spray dryer such that the water present evaporates as it contacts the hot flue gas. The sulfur dioxide in the flue gas reacts with the lime as it dries and results in a dry particulate product that is captured in a downstream fabric filter; no wastewater is generated from the dry FGD process. In wet FGD systems, the flue gas stream comes in contact with a liquid stream containing a sorbent, typically lime or limestone, which is used to effect the mass transfer of pollutants from the flue gas to the liquid stream. This process not only transfers the sulfur dioxide from the flue gas to the liquid stream, but other pollutants (e.g., metals) as well. During this process, the lime/limestone and sulfur dioxide react to form calcium sulfite or calcium sulfate (i.e., gypsum), depending on the oxidation level of the FGD system. Gypsum is a marketable product, and as such, plants that generate gypsum generally sell (or give away) the material for use in building materials (e.g., wallboard). Plants that do not generate gypsum, or only partially oxidize the calcium sulfite, generally dispose of their FGD solids in landfills or surface impoundments. Those plants that produce a saleable product, such as gypsum, may rinse the product cake to reduce the level of chlorides in the final product. This wash water may be reused or discharged to a receiving water or POTW. Additionally, both calcium sulfite and gypsum typically require dewatering prior to sale/disposal and this dewatering process also generates a wastewater stream that may be reused or discharged. The FGD system generally requires a blowdown stream to purge chlorides to prevent scaling and corrosion of the FGD equipment.

FGD wastewater is typically an intermittent stream generated by coal-fired power plants operating wet FGD systems. Based on responses to the industry survey, the average FGD wastewater flow rate is 559,000 gallons per day (gpd). EPA estimates that the steam electric industry discharged a total of 23.7 billion gallons of FGD wastewater in 2009.

Based on the responses to the industry survey, there are approximately 401 FGD systems either currently operating or that will be installed by January 1, 2014.[9] Approximately 90 of the currently operating FGD systems are dry systems that do not generate any wastewater streams, while 311 systems are wet FGD systems.[10]

3. Flue Gas Mercury Control (FGMC) Systems

FGMC systems remove mercury from the flue gas, so that it is not emitted into the air. According to the responses to the industry survey, two main types of

[9] Because EPA expects to take final action on this rule in 2014, EPA used 2014 as the baseline year for its analysis. EPA is considering using alternative dates, such as 2022 which may better reflect the implementation timeframe for the ELG, for the baseline year for its analyses for the final rule.

[10] This is not the number of steam electric power plants with wet FGD systems. An individual steam electric power plant may operate one or more FGD systems.

systems are currently in use in the industry: (1) Addition of oxidizers to the coal prior to combustion, whereby the oxidized mercury is removed in the wet FGD system; and (2) injection of activated carbon into the flue gas which adsorbs the mercury and is captured in a downstream particulate removal system.

The use of the oxidizers 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. The activated carbon injection system does have the potential to 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) is 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 and likely sent to the same surface impoundment. In this case, adding the FGMC wastes to the fly ash can increase the amount of mercury in the fly ash transport water. 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 the carbon in FGMC wastes can make 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 industry survey, in 2009 there were approximately 120 operating FGMC systems, with an additional 40 planned for installation by 2020. 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. For the remaining 4 percent of the systems, the type of handling system (e.g., wet or dry handling) is unknown.

4. Combustion Residual Leachate From Surface Impoundments and Landfills

Combustion residuals comprise a variety of wastes from the combustion process, including fly ash, bottom ash (which includes boiler slag), and FGD solids (e.g., gypsum and calcium sulfite), which are generally collected by or generated from the air pollution control technologies. These combustion residuals may be stored at the plant in on-site landfills or surface impoundments (i.e., ponds). Based on industry survey results, there are approximately 228 plants that operate combustion residual landfills and 264 plants that operate combustion residual surface impoundments. Some plants operate both landfills and impoundments, while other plants may operate only one or the other, or neither type of disposal unit.

Leachate is the liquid that drains or leaches from a landfill or surface impoundment. Most landfills have a system to collect the leachate and some impoundments have leachate collection systems. The two sources of leachate are precipitation that percolates through the waste deposited in the landfill/impoundment and the liquids produced from the combustion residuals placed in the landfill/impoundment. In addition to leachate, stormwater that enters the impoundment or contacts and flows over the landfill would be contaminated with combustion residual pollutants. Leachate and contaminated stormwater contain heavy metals and other contaminants through the contact with the combustion residuals.

Some landfills and surface impoundments are lined. In a lined landfill/impoundment, the leachate collected in the liner typically flows through a collection system consisting of ditches and/or underground pipes. From the collection system, the leachate is transported to an impoundment (e.g., collection pond). The stormwater collection systems typically consist of one or more small impoundments or collection ponds. The leachate and stormwater may be treated in separate impoundments or combined together. Some plants discharge the effluent from these leachate impoundments, while other plants send the leachate impoundment effluent to another impoundment handling the ash transport water or other treatment system (e.g., constructed wetlands). Unlined impoundments and landfills usually do not collect leachate thereby leaving the leachate to potentially migrate to nearby ground waters, drinking water wells, or surface waters.

Based on responses to the industry survey, approximately 100 plants collect landfill leachate from approximately 110 existing (i.e., active or inactive) landfills containing CCR, while approximately 50 plants collect leachate from existing CCR surface impoundments. Another 40 plants collect leachate from both types of systems.

Leachate is an intermittent stream whose flow rate, frequency, and duration are generally determined by weather conditions. For this reason, leachate flow rates can vary greatly for a plant, as well as varying from one plant to another. Additionally, there are differences in flow rates depending on whether the landfill or surface impoundment is active/inactive or retired. Retired landfills or surface impoundments tend to have lower flow rates because they have been capped or closed and, therefore, are not open to the atmospheric rainfall. Based on the industry survey, the average active/inactive landfill leachate flow rate was approximately 60,000 gpd. EPA estimates that the steam electric industry discharged approximately 6.2 billion gallons of leachate in 2009.

5. Gasification Processes

As described above, IGCC plants uses a carbon-based feedstock (e.g., coal or petroleum coke) and subject it to high temperature and pressure to produce a synthetic gas (''syngas'') which is used as the fuel for a combined cycle generating unit. In these IGCC plants, after the syngas is produced, it undergoes cleaning prior to combustion. The cleaning processes can involve any number of the following processes:

- Water scrubbing;
- Carbonyl-sulfide hydrolysis;
- Acid gas removal (stripping); and
- Sulfur recovery.

The wastewater generated by these processes, along with any condensate generated in flash tanks, slag handling water, or wastewater generated from the production of sulfuric acid, are referred to as ''grey water'' or ''sour water,'' and require treatment prior to reuse or discharge.

EPA identified two plants currently operating IGCC units, and a third IGCC unit is scheduled to begin operation this year. A fourth IGCC power plant is under construction and is scheduled to begin commercial operation in 2014.

The gasification processes generally operate continuously and, therefore, generate most of the individual gasification wastestreams continuously. Based on the information collected during EPA's sampling program, EPA determined the gasification wastewater transferred to the treatment system ranged from 6,000 to 109,000 gpd, with an average flow of 66,000 gpd.

6. Metal Cleaning Wastes

The 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.'' 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 industry 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 raw or potable water to clean the air heater.

The following types of metal cleaning wastes were reported in responses to the industry 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.

7. Carbon Capture and Storage Systems

The industry is investigating carbon capture and storage systems to remove carbon dioxide (CO_2) from the flue gas. Many steam electric power plants are considering alternatives available for reducing CO_2 emissions; however, according to the industry survey responses, there are no full-scale carbon capture systems currently operating. EPA obtained information about two pilot-scale systems that operated in recent years; however, neither of these systems is currently operating. Additionally, several plants reported in their survey responses that they are planning to install a pilot-scale carbon capture system and some plants reported plans to install full-scale systems by 2020.[11]

There are three main approaches for capturing the CO_2 associated with generating electricity: Post-combustion, pre-combustion, and oxyfuel combustion.

- In post-combustion capture, the CO_2 is removed after combustion of the fossil fuel.
- In pre-combustion capture, the fossil fuel is partially oxidized, such as in a gasifier. The resulting syngas (CO and H_2) is processed to create 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 oxy-fuel combustion, also known as oxy-combustion, the fuel is burned in oxygen instead of air. The flue gas consists of mainly CO_2 and water vapor; the latter condenses through cooling. The result is an almost pure CO_2 stream that can be transported to the sequestration site and stored.

Based on preliminary information regarding these technologies, EPA believes they may result in new wastewaters at steam electric power plants. 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 its sampling program, EPA obtained analytical data associated with two wastestreams generated from a post-combustion carbon capture system. Because of the small size of the pilot-scale system, the plant transferred the wastewater off site for treatment.

C. Control and Treatment Technologies

EPA evaluated the technologies available to control and treat wastewater generated by the steam electric industry. Individual plants may use one or more processes that generate wastewater streams. They may treat these wastestreams separately or in various combinations. For this reason, EPA evaluated available technologies for each major wastestream separately.

1. FGD Wastewater

EPA identified 145 steam electric power plants that generate FGD wastewater. Of these, 117 plants (81 percent) discharge FGD wastewater after treatment using one or more of the following technologies:

- *Surface Impoundments:* Surface impoundments (e.g., settling ponds), designed to remove particulates from wastewater by means of gravity, may be configured as one impoundment or a series of impoundments. Impoundments are typically sized to allow for a certain residence time to enable the suspended solids to settle to the bottom. The impoundments are also designed to have sufficient capacity to allow for temporary storage or permanent disposal of the settled solids. Surface impoundments are not designed to remove dissolved metals. Plants may add treatment chemicals to the impoundment, typically to adjust pH before final discharge.

There are 63 plants (54 percent of the discharging plants) that use surface impoundments as the only type of treatment for FGD wastewaters. Most (49) of these plants also combine their FGD wastewater with other plant wastewater while the remainder (14) use impoundments to treat FGD wastewater alone. Additional plants (above and beyond the 63 plants described in the preceding sentences) also use surface impoundments to remove suspended solids prior to a more advanced treatment process, such as chemical precipitation or biological treatment.

- *Chemical Precipitation:* Some plants use chemical precipitation systems instead of or in addition to surface impoundments. Chemical precipitation treatment is a tank-based system in which chemicals are added to enhance the removal of suspended solids and dissolved solids, particularly certain dissolved metals. The dissolved metals amenable to chemical precipitation treatment are removed from aqueous solutions by converting soluble metal ions to insoluble metal hydroxides or sulfides. The precipitated solids are then removed from solution by coagulation/flocculation followed by clarification and/or filtration. Chemical reagents such as lime (calcium hydroxide), sodium hydroxide, and ferric chloride are used to adjust the pH

[11] In order to protect CBI claims, EPA cannot provide specific numbers.

of the water to reduce the solubility of the metal(s) targeted for removal.

Some plants also use sulfide chemicals (e.g., organosulfides or sodium sulfide) to precipitate and remove heavy metals, including mercury. Sulfide precipitation is more effective than hydroxide precipitation in removing mercury because mercury sulfides have lower solubilities than mercury hydroxides. Other metal sulfide compounds also typically have lower solubilities than metal hydroxide compounds. 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 sulfide treatment chemicals.

EPA identified 40 plants (34 percent of the discharging plants) that treat their FGD wastewater using chemical precipitation (in some cases, also employing additional treatment steps such as biological treatment). Lime is the most commonly used treatment chemical to perform the pH adjustment needed for these systems. Sulfide precipitation, alone or in combination with hydroxide precipitation, is used by 33 plants (28 percent of the discharging plants). Most plants operating chemical precipitation treatment systems for FGD wastewater employ ferric chloride addition (i.e., iron coprecipitation) as part of the treatment process.

• *Biological Treatment:* Some steam electric power plants also treat FGD wastewater using biological treatment systems. An anoxic/anaerobic biological system being used in the industry is effective at removing both metals (total and dissolved) and nutrients. This system is designed to significantly reduce nitrogen compounds and selenium. These fixed-film bioreactors are designed for plug flow operation and have zones of differing oxidation potential that allow for nitrification and denitrification of the wastewater and reduction of metals, such as selenium. The system 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.

EPA identified five plants that operate the fixed-film anoxic/anaerobic biological treatment systems to treat FGD wastewater, and another plant recently installed a suspended growth biological treatment system that targets removal of selenium and other metals.[12] Four of these six plants also operate chemical precipitation systems prior to the biological treatment system. There are also at least four other plants that operate aerobic/anaerobic sequencing batch reactors to treat FGD wastewater that has already undergone chemical precipitation. These systems are capable of removing organics and nutrients, but are not operated in a manner to remove selenium or 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. With pretreatment, such as chemical precipitation and softening, brine concentrators can reduce wastewater volumes by 80 to 90 percent. Plants can further process the concentrated wastewater stream in a crystallizer or spray dryer, which evaporates the remaining water to generate a solid waste product and potentially a condensate stream. The distillate and condensate streams may be reused within the plant or discharged to surface waters. EPA identified two U.S. plants and four Italian plants that treat FGD wastewater using vapor-compression evaporation. A third U.S. plant is currently installing a vapor-compression evaporation treatment system; it is scheduled to be operational by the end of 2013.

• *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. High temperature, chemical oxygen demand (COD), nitrates, sulfates, boron, and chlorides in wastewater can adversely affect constructed wetlands performance. To overcome this, plants typically dilute FGD wastewater with service water (i.e., supply water used widely throughout the plant for a variety of uses) before it enters a constructed wetland.

EPA identified three plants that treat their FGD wastewater using constructed wetlands. The constructed wetlands used to treat FGD wastewater typically are designed to treat only the FGD wastewater (and the service water used for dilution); however, because these systems are open to the environment, they also receive stormwater from the surrounding areas.

• *Other Technologies:* EPA identified several other technologies that have been evaluated for treatment of FGD wastewater, including iron cementation, reverse osmosis, absorption or adsorption media, ion exchange, and electro-coagulation. Other technologies under laboratory-scale study include polymeric chelates, taconite tailings, and nano-scale iron reagents. Most of these technologies have been evaluated only as pilot-scale studies; however, two of these technologies are currently operating at full-scale to treat FGD wastewater. One 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. Another plant treats the FGD wastewater with chemical precipitation, 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.

• *Design/Operating Practices Achieving Zero Discharge:* EPA identified four design/operating practices available enabling plants to eliminate the discharge of wastewater from wet FGD systems: 1) Several variations of complete recycle, 2) evaporation ponds, 3) conditioning dry fly ash, and 4) underground injection. Of the 145 plants that generate wastewater from FGD processes, 28 plants (19 percent) operate in such a manner that they do not discharge wastewater to surface waters or POTWs. Many of the plants in the southwestern United States that generate FGD wastewater use evaporation ponds that do not discharge.

2. Fly Ash Transport Water

Fly ash separated from boiler exhaust by electrostatic precipitators (ESPs) or fabric filters is collected in hoppers located underneath the equipment. From the collection hoppers, the fly ash is either transferred as dry ash to silos for temporary storage or transported (sluiced) with water to a surface impoundment (i.e., ash settling pond). Plants that generate fly ash transport

[12] A seventh plant is scheduled to begin operating a biological treatment system for selenium removal in 2014. This plant is not included in this summary of biological treatment systems.

water use surface impoundments to manage the wastewater. EPA has not identified any facilities using more advanced treatment, such as chemical precipitation or biological treatment, to treat fly ash transport water. EPA identified 393 generating units (at 144 plants) that wet sluice at least a portion of fly ash. Wet sluicing systems use water-powered hydraulic vacuums to withdraw fly ash from the hoppers. The ash is pulled to a separator/transfer tank, combined with sluicing water, and pumped to the surface impoundment to remove particulates from the wastewater by means of gravity, before discharge to a receiving stream.

Many coal and oil-fired power plants design their fly ash handling systems to minimize or eliminate the discharge of fly ash handling transport water. Such approaches include:

• *Wet Vacuum Pneumatic System:* These systems use water-powered hydraulic vacuums for the initial withdrawal of fly ash from the hoppers, similar to wet sluicing systems. Instead of sluicing the ash to a surface impoundment, these systems capture the ash in a filter-receiver (bag filter with a receiving tank) and then deposit the dry ash in a silo.

• *Dry Vacuum Pneumatic 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. The fly ash empties from the hoppers in to the conveying system via a material handling valve.

• *Pressure System:* These systems use air produced by a positive displacement blower to convey ash directly from the hopper to a silo. Each ash collection hopper is equipped with airlock valves that transfer the fly ash from low pressure to high pressure in the conveying line. The airlock valves are installed at the bottom of the hoppers and require a significant amount of space. Retrofit installations of pressure ash handling systems may require raising the bottom of the hopper.

• *Combined Vacuum/Pressure System:* These systems use a dry vacuum system to pull ash from the hoppers to a transfer station, where the ash is transferred from the vacuum (low pressure) to ambient pressure. From the transfer station, the fly ash is transferred via airlock valves to a high pressure conveying line. A positive displacement blower conveys the ash to a silo. Because the airlocks are not located under the hopper, combination vacuum/pressure systems have the space advantages of dry vacuum systems.

• *Mechanical System:* Oil-fired units or other units that generate a low volume of fly ash may use manual or systematic approaches to remove fly ash (e.g., scraping the sides of the boilers with sprayers or shovels, then collecting and removing the fly ash to an intermediate storage destination or disposal).

The following identifies the number of units (and plants) in the steam electric industry operating each of the different technologies available to eliminate the discharge of fly ash transport water:

• Wet vacuum pneumatic system—51 units (22 plants);
• Dry vacuum pneumatic system—485 units (220 plants);
• Pressure system—188 units (91 plants);
• Combined vacuum/pressure system—223 units (102 plants);
• Mechanical system—16 units (13 plants); and
• Other dry systems—5 units (3 plants).

3. Bottom Ash Transport Water

Bottom ash (at times also referred to as boiler slag) is produced as fuel is burned in a boiler and collected in hoppers or other types of collection equipment directly below the boiler. Generally, boilers are sloped inward, with an opening at the bottom to allow the bottom ash to feed by gravity into collection hoppers. The hoppers contain water to quench the hot ash. Once the hoppers are full, gates at the bottom of the hoppers open, releasing the bottom ash and quench water to a conveying line, where the ash is diluted with water to approximately 20 percent solids (by weight) and pumped to a surface impoundment or a dewatering bin for solids removal. Conveying bottom ash in a water slurry is called wet sluicing. EPA identified 870 units (345 plants) that wet sluice at least a portion of their bottom ash. For further information, see Section 4.3.2 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13–002.

Many coal and oil-fired power plants design their bottom ash handling systems to reduce or eliminate the discharge of bottom ash handling transport water. Available technologies include:

• *Mechanical Drag System:* In these systems, the ash collection hopper is replaced with a transition chute that routes the bottom ash to a water-filled trough. In the trough, a drag chain continuously moves the ash to an incline where it is dewatered and then conveyed to a nearby ash collection area. Excess quench water collected in the dewatering system is recycled to the quench water bath.

Although mechanical drag systems require little space under the boiler they may not be suitable for all boiler configurations.

In the steam electric industry, 99 coal-fired units use mechanical drag systems for bottom ash handling. Operators have announced plans to retrofit mechanical drag systems on additional units by 2020. EPA estimates that these announced retrofits include approximately 10–30 generating units. (Note: the precise value has been withheld to prevent disclosing CBI.)

• *Remote Mechanical Drag System:* These systems collect bottom ash in water-filled hoppers and wet sluice the ash to a mechanical drag system located away from the boilers. Sluice water collected from the dewatered bottom ash is collected and reused in the bottom ash handling system. Plants can use remote mechanical drag systems to convert existing bottom ash handling systems with limited space or other configuration limitations. One U.S. plant has installed and is currently operating a remote mechanical drag system to handle bottom ash. At least one additional plant is currently installing a remote mechanical drag systems to handle bottom ash. Additionally, a large U.S. power company has been evaluating installing remote mechanical drag systems for several of its plants.

• *Dry Vacuum or Pressure System:* These systems transport bottom ash from the boiler to a dry hopper without using any water. The system percolates air 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.

• *Complete Recycle System:* Complete recycle systems transport bottom ash using the same processes as wet sluicing systems. Plants can install complete recycle on existing wet sluicing units. Instead of transporting it to an impoundment, the ash is sluiced to dewatering bins, where it is dewatered and moved to storage. The transport (sluice) water is treated to remove solids in a settling tank and is recycled to the bottom ash collection system. Prior to reusing the treated transport water, plants may add treatment chemicals to the water to adjust pH and prevent equipment corrosion.

• *Vibratory Belt System:* Bottom ash deposits on a vibratory conveyor trough, where the plant cools the ash by air and ultimately moves it through the conveyor deck to an intermediate storage destination.

• *Mechanical System:* Oil-fired units or other units that generate a low volume of bottom ash, may use manual or systematic approaches to removing ash that accumulates in the boiler (e.g., scraping the sides of the boilers with sprayers or shovels, then collecting and removing the bottom ash to an intermediate storage destination or disposal).

The following identifies the number of units (and plants) in the steam electric industry operating each of the different technology options available to eliminate or minimize the amount of bottom ash transport water:

• Mechanical drag system—99 units (74 plants);
• Remote mechanical drag system—at least 2 units (2 plants) installing systems since 2009;
• Dry vacuum system—111 units (68 plants);
• Dry pressure system—13 units (11 plants);
• Complete recycle systems—at least 20 plants; and
• Mechanical systems—38 units (19 plants).

4. Combustion Residuals Leachate From Landfills and Surface Impoundments

Plants often treat combustion residual landfill leachate with some of the same technologies used to treat FGD wastewater as described in Section VI.C.1. EPA identified 102 coal-fired power plants that generate and discharge leachate. Based on the responses to the industry survey, 29 of these plants treat the leachate prior to discharge using surface impoundments, constructed wetlands, or biological treatment. In some cases, plants co-treat the leachate with FGD wastewaters and, in some cases, treat the leachate independently.

Based on information from the industry survey and site visits, surface impoundments are the most common type of system used to treat combustion residual leachate from landfills and impoundments. Constructed wetlands are the next most commonly used treatment system. The anoxic/anaerobic biological treatment system used as the basis for FGD wastewater effluent limits in this proposed rule is also being used by one plant to treat leachate, with the leachate mixing with FGD wastewater immediately prior to the bioreactor stage.

Some plants mix the leachate with fly ash prior to disposing the ash in a landfill to control fugitive dust emissions and to improve the handling characteristics of the dry fly ash. Leachate is also used at some plants for dust control around ash loading areas and landfills. Many plants will collect the leachate from a surface impoundment and pump it directly back to the impoundment from which it originated.

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 have also been identified as 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).

5. Gasification Wastewater

The treatment technologies in use at steam electric power plants for gasification wastewater include:

• *Vapor-Compression Evaporation System:* This type of system is identical to the vapor-compression evaporation system described for FGD wastewater. It 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 or spray dryer, which evaporates the remaining water to generate a solid waste product and potentially a condensate stream. Facilities may reuse the distillate and condensate streams within the plant or discharge them to surface waters.

• *Cyanide Destruction System:* This system adds sodium hypochlorite (i.e., bleach) to the wastewater in mixing tanks to destroy the cyanide. The cyanide system treats the condensate and distillate streams from both the brine concentrator and crystallizer just prior to discharge.

EPA is aware of two plants that currently operate integrated gasification combined cycle (IGCC) units in the United States, and a third plant is scheduled to begin operating an IGCC unit this year. All three of these plants currently treat or plan to treat the IGCC wastewaters with vapor-compression evaporation systems. The IGCC plant scheduled to begin operating this year is installing both a vapor-compression evaporation system and a cyanide destruction system to treat the gasification wastewater.

6. Flue Gas Mercury Control (FGMC) Wastewater

FGMC wastewater originates from activated carbon injection systems. The system can be configured either upstream or downstream of the primary particulate collection system. EPA identified 73 plants with current or planned activated carbon injection systems. Of these, 58 plants operate upstream injection systems while the remaining 15 plants inject the carbon downstream.

In cases where the injection occurs upstream of the primary particulate collection system, plants collect and handle the mercury-containing carbon with the fly ash. In cases where the injection occurs downstream of the primary particulate collection system, plants collect the mercury-containing carbon in a secondary particulate control system (e.g., a fabric filter). As with fly ash systems, plants collect the mercury-containing carbon in hoppers located underneath the equipment. From the collection hoppers, plants either transfer the mercury-containing carbon as dry ash to silos for temporary storage (67 plants; 92 percent) or transport (sluice) it with water to an ash impoundment (6 plants; 8 percent). Water transport can result in a wastewater discharge, typically an overflow from the impoundment. However, five of the six plants that use water to transport the FGMC waste to a surface impoundment do not discharge any FGMC wastewater and the remaining plant has the capability to handle the FGMC waste using a dry system but sometimes uses a wet system instead.

Coal-fired power plants can minimize or eliminate the discharge of FGMC particulate handling transport water by using the same solids handling technologies that are available for fly ash. These technologies include:

• *Wet Vacuum Pneumatic System:* These systems use water-powered hydraulic vacuums to withdraw dry FGMC waste from the hoppers, similar to wet sluicing systems. Instead of sluicing the FGMC waste to a surface impoundment, these systems capture the FGMC waste in a filter—receiver (bag filter with a receiving tank) and then deposit it in a silo.

- *Dry Vacuum Pneumatic System:* These systems use a mechanical exhauster to move air, below atmospheric pressure, to pull the FGMC waste from the hoppers and convey it directly to a silo. The collected FGMC waste empties from the hoppers into the conveying system via a material handling valve.
- *Pressure System:* These systems use air produced by a positive displacement blower to convey FGMC waste directly from the hopper to a silo.
- *Combined Vacuum/Pressure System:* These systems first utilize a dry vacuum system to pull FGMC waste from the hoppers to a transfer station, and then use a positive displacement blower to convey it to a silo.

7. Metal Cleaning Wastes

As described in Section VI.B.6, metal cleaning wastes are generated from cleaning any metal process equipment. Because there are many different processes at plants that use metal equipment, there are a variety of metal cleaning wastes that are generated. The treatment methods used for each of the different types of metal cleaning wastes vary to some degree depending on the specific cleaning operations.

Based on information from the industry survey, surface impoundments and chemical precipitation systems are two of the most common types of systems used to treat metal cleaning wastes. Other types of treatment systems include constructed wetlands, filtration, reverse osmosis, clarification, oil/water separation, and brine concentrators.

In addition to the treatment systems used to control the discharges of metal cleaning wastes, some plants also employ other handling approaches to control or eliminate the discharge of metal cleaning wastes. For example, some plants immediately recycle the metal cleaning wastes back to other plant operations, while other plants evaporate the metal cleaning wastes in the boiler to evaporate the wastewater and eliminate the discharge. Other handling operations reported in the industry survey include offsite treatment, hazardous waste disposal, third-party disposal, mixing with fly ash and landfilling, and deep well injection.

Physical/chemical treatment systems are capable of reducing the concentration of pollutants, including metals, in the wastewater.

VII. Selection of Regulated Pollutants

A. Identifying the Pollutants of Concern

The following paragraphs discuss the pollutants of concern identified for each of the wastestreams considered for regulation in this proposal. For the purpose of this rulemaking, pollutants of concern are those pollutants that have been quantified in a wastestream at sufficient frequency at treatable levels (i.e., concentrations). EPA used the following sources of wastewater characterization data to identify pollutants of concern in wastewater from steam electric power plants: EPA's field sampling program, industry-supplied data including data provided in responses to the industry survey, and various literature sources. EPA relied primarily on its field sampling program data because the data were collected using consistent methods and analytical techniques for a broad range of pollutants. Therefore, where EPA had data from its field sampling program, it preferentially used that data. Where EPA did not collect field sampling data for a wastestream and industry-supplied data was available, EPA used that data. In the absence of either EPA field sampling data or industry-supplied data, EPA used literature data.

After reviewing the available sources of data for each of the wastestreams addressed by this rulemaking, EPA first combined the pollutant data to create consolidated datasets representing the concentrations of pollutants present in each wastestream prior to treatment. EPA then eliminated all pollutants that were not detected in any wastewater samples—any pollutants falling into this category are not considered pollutants of concern. Finally, for the remaining pollutants for each wastestream, EPA then identified each pollutant that was detected at a concentration greater than or equal to ten times the baseline value (see Section 6 of the TDD) in at least 10 percent of all untreated process wastewater samples.[13]

EPA identified the following 34 pollutants of concern for FGD wastewater using EPA field sampling data: one conventional pollutant (TSS);[14] 13 toxic pollutants, including arsenic, cyanide, mercury, and selenium; 12 nonconventional metals; and 8 other nonconventional pollutants (e.g., ammonia, nitrate/nitrite, and total phosphorus).

EPA identified the following 24 pollutants of concern for fly ash transport water using EPA field sampling data: one conventional pollutant (TSS);[15] 9 toxic pollutants (metals including arsenic, lead, mercury, and selenium); 11 nonconventional pollutant metals; and 3 other nonconventional pollutants (i.e., TDS, chloride, and nitrate/nitrite).

EPA was unable to obtain readily available data for untreated bottom ash transport water for use in identifying the pollutants of concern using the methodology described above. However, because the pollutants found in bottom ash are constituents that are present in the coal (or petroleum coke or oil), as is the case for fly ash, EPA concluded that the pollutants of concern for bottom ash transport water are identical to the pollutants of concern identified for fly ash transport water.

EPA was also unable to obtain readily available data for identifying the pollutants of concern in FGMC wastewater. Nevertheless, based on process knowledge and engineering judgment, EPA concluded that the pollutants of concern for FGMC wastewater are likely to be identical to the pollutants of concern identified for fly ash transport water. This is due to the fact that, when activated carbon is injected into the flue gases, the carbon intermixes with the fly ash particles, and then the commingled mixture of activated carbon (which adsorbs mercury and other pollutants from the flue gases) and fly ash particles is captured together and transferred to the FGMC wastewater.

EPA evaluated the pollutants of concern for combustion residual leachate using industry sampling data for untreated leachate submitted under Part G of the industry survey. EPA evaluated the landfill leachate separately from the surface impoundment leachate. The pollutants of concern for landfill leachate include the following: one conventional pollutant (TSS);[16] 3 toxic pollutants

[13] This 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 in treatable levels.

[14] EPA did not analyze its field sampling data for oil and grease. Rather, since the existing steam electric ELG currently contains 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.

[15] EPA did not analyze its field sampling data for oil and grease. Rather, since the existing steam electric ELG currently contains BPT limitations applicable to fly ash transport wastewater 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 wastewater.

[16] The landfill leachate samples were not analyzed for oil and grease. Rather, since the existing steam electric ELG currently contains BPT limitations applicable to combustion residual leachate for oil and grease, EPA already has data from the existing rulemaking demonstrating oil and

Continued

(arsenic, mercury, and selenium); 9 nonconventional pollutant metals; and 3 other nonconventional pollutants (i.e., chloride, sulfate and TDS). The pollutants of concern for impoundment leachate include:[17] 2 toxic pollutants (i.e., arsenic and mercury), 7 nonconventional pollutant metals, and 3 other nonconventional pollutants (i.e., chloride, sulfate, and TDS).

EPA identified 19 pollutants of concern for gasification wastewater using EPA field sampling data, including: 1 conventional pollutant (BOD); 7 toxic pollutants (including arsenic, cyanide, mercury, and selenium); 5 nonconventional pollutant metals; and 6 other nonconventional pollutants.

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, copper, and iron were pollutants of concern for this wastestream warranting regulation and established BPT limitations for these four pollutants in discharges of metal cleaning wastes, including both nonchemical and chemical metal cleaning wastes. (EPA has also established BAT, NSPS, PSES, and PSNS for chemical metal cleaning wastes.) 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.* Based on the information developed for the previous rulemakings for the steam electric power generating ELGs and the data from the industry survey, EPA identified 4 pollutants of concern for nonchemical metal cleaning wastes, including: 2 conventional pollutants (TSS and oil and grease); 1 toxic pollutant (copper); and 1 nonconventional pollutant (iron).

See Section 6 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13–002 for more detailed information regarding pollutants of concern.

B. Selection of Pollutants for Regulation Under BAT/NSPS

The pollutants of concern identified for each wastestream represents those pollutants that are present at treatable concentrations in a significant percentage of untreated wastewater samples from that wastestream. Effluent limits and monitoring for all pollutants of concern is not necessary to ensure that the pollutants are adequately controlled because many of the pollutants originate from similar sources, have similar treatabilities, and are removed by similar mechanisms. Because of this, it may be sufficient to establish effluent limits for one pollutant as a surrogate or indicator pollutant that ensures the removal of other pollutants of concern. In addition, establishing effluent limits may not be appropriate for certain pollutants of concern when the technology used as the basis for the effluent limits is not reliably effective at removing the pollutant(s).

From the list of pollutants of concern identified for each wastestream, EPA selected a subset of pollutants for establishing numeric effluent limitations. EPA considered the following factors in selecting regulated pollutants from the list of pollutants of concern:

- The pollutant was detected in the untreated wastewater at treatable levels in a significant number of samples.
- The pollutant is not used as a treatment chemical in the treatment technology that serves as a basis for the proposed regulatory option. EPA eliminated pollutants associated with treatment system additives 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 all pollutants for which the treatment technology was ineffective (e.g., pollutant concentrations remained approximately unchanged or increased across the treatment system).
- The pollutant is not adequately controlled through the regulation of another pollutant.

Because the criteria for identifying regulated pollutants from the list of pollutants of concern depends on the treatment technology that serves as the basis for a proposed regulatory option, EPA may regulate a different subset of pollutants for a single wastestream under different regulatory options.

For the proposed options for this rulemaking (described below in Section VIII), EPA identified six pollutants for potential regulation for FGD wastewater: oil and grease, TSS, arsenic, mercury, nitrate/nitrite, and selenium. For leachate, EPA identified four potential pollutants for regulation: oil and grease, TSS, arsenic and mercury.

For fly ash discharges, bottom ash, and FGMC wastewater, under some proposed options, EPA is proposing to establish zero discharge limitations, which in effect directly control all pollutants of concern. For other proposed options that would not require zero pollutant discharge, EPA identified two potential pollutants for regulation: oil and grease and TSS for nonchemical metal cleaning wastes, EPA identified four pollutants for potential regulation (TSS, oil and grease, copper, and iron). EPA identified four pollutants for regulation for gasification wastewater: arsenic, mercury, selenium, and TDS.

See Section 6.7 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13–002 for more information about the pollutants of concern and EPA's rationale for selecting the pollutants proposed for regulation.

C. Methodology for the POTW Pass Through Analysis (PSES/PSNS)

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 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.

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 through POTWs, EPA generally compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment

grease is also a pollutant of concern in combustion residual leachate.

[17] The surface impoundment leachate samples were not analyzed for oil and grease. Rather, since the existing steam electric ELG currently contains BPT limitations applicable to combustion residual leachate for oil and grease, EPA already has data from the existing rulemaking demonstrating oil and grease is also a pollutant of concern in combustion residual leachate.

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.

For this proposed rule, EPA conducted a pass through analysis for the technology basis for each wastestream for each regulatory option presented below in Section VII.C. For those wastestreams and regulatory options for which EPA is proposing zero discharge of pollutants, EPA set the percentage removed by the technology basis at 100 percent. EPA did not conduct its traditional pass-through analysis for these wastestreams (e.g., fly ash transport water, bottom ash transport water, and flue gas mercury control wastewater) because limitations for these wastestreams for direct dischargers would consist of no discharge of process wastewater pollutants to waters of the U.S., and therefore, all 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. For this rulemaking, 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.

For FGD wastewater, leachate, and gasification wastewater, EPA determined the percentage removed for the pollutants by the technology basis using the same data sources used to determine the long-term averages for each set of limitations (see Section 13 of the TDD).[18] As it has done for other rulemakings, EPA determined the percentage removed by well-operated POTWs performing secondary treatment from one of two 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).

The 50 POTW study presents data on the performance of 50 POTWs achieving secondary treatment in removing toxic pollutants. When data for a pollutant were available from the 50 POTW Study, EPA used that data. When data for pollutants were not available from the 50 POTW Study, EPA used NRMRL data. The NRMRL treatability database provides information on removals obtained by various treatment technologies for a variety of wastewater sources. Therefore, where EPA used data from the NRMRL treatability database, it used only data from the treatment of domestic and industrial wastewater using technologies representative of secondary treatment. For a more detailed discussion of how EPA performed its removal analysis, see Section 11 of the TDD.

With a few exceptions, EPA performs a POTW pass-through analysis for pollutants selected for regulation for BAT/NSPS for each wastestream of concern and for each regulatory option. The exception is for conventional pollutants such as BOD_5, TSS, and oil and grease. POTWs are designed to treat these conventional pollutants; therefore, they are not considered to pass through.

Section VIII below summarizes the results of the pass through analysis. All of the pollutants proposed for regulation under BAT/NSPS (except for conventional pollutants and iron found in nonchemical metal cleaning wastes) were found to pass through and, therefore, were selected for regulation under PSES/PSNS.

[18] For FGD wastewater and leachate, this discussion applies to those regulatory options that would provide additional control for discharges of toxics like arsenic, mercury and selenium.

VIII. Proposed Regulation

A. Regulatory Options

1. BPT/BCT

EPA is not proposing to revise the BPT effluent guidelines or establish BCT effluent guidelines in this notice 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 part 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.

2. Description of the 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. In Section VI of this preamble and in the TDD, EPA describes the treatment technologies and operational practices that it 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. In this proposal, 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 VIII–1 summarizes the eight main regulatory options, which are described in the paragraphs below.

As discussed further below, 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 below in the paragraph titled, ''BMPs for CCR Surface Impoundments.''

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. As described further below, EPA proposes that certain limitations and standards being proposed today 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 this proposed rule. As described further below, 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 VIII–1—STEAM ELECTRIC MAIN REGULATORY OPTIONS

Wastestreams	Technology basis for the main 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
Combustion Residual 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[19].	Chemical Precipitation.	Chemical Precipitation.	Chemical Precipitation.	Chemical Precipitation.	Chemical Precipitation.	Chemical Precipitation.	Chemical Precipitation.	Chemical Precipitation

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

[19] 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.

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.

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 denser, 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 loads 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 VII.A.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 VIII.A.3, EPA also 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)[20], 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. 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.[21] 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 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, as described above and in the TDD. 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.[22]

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 of the TDD 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 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 CFR 403.5(c)(2).

As described below in this section of the preamble, EPA is proposing that certain limitations and standards being proposed today 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 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,

[20] This value is calculated by summing the nameplate capacity for all of the units that are serviced by wet FGD systems.

[21] 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.

[22] A third U.S. plant is currently installing a vapor-compression evaporation system to treat the FGD wastewater.

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 today, 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 XVI for additional information.

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 above in Section VI of this preamble and in the TDD for the proposed rule. 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 VI, 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. Since 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 in this proposed rule. See DCN SE03869.

As described below in this section of the preamble, 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 above 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 today, 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 XVI for additional information.

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 VI of this preamble and in the TDD for the proposed rule. 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. Since 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. See DCN SE03869.

As described below in this section of the preamble, 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, as described above), 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 today, 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 XVI for additional information.

Combustion Residual Leachate. 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 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 and the TDD presents information about the compliance costs and pollutant removals associated with this technology. 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 would (although it is not proposing such limits as a preferred option today), 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 today, 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 XVI for additional information.

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 above in Section VI of this preamble, 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 above in section VI of this preamble and in the TDD for the proposed rule. 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 today, 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 explained above, 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 above 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 XVI for additional information.

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. EPA solicits data on the concentrations of cyanide present in gasification wastewater and solicits comment on whether EPA should establish BAT or BADCT (NSPS) control on the discharge of cyanide.

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 VIII.A.3 and Section 7.7 of the TDD 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 existing ELGs for metal cleaning waste, including chemical and nonchemical metal cleaning waste, is provided below in Table VIII–2.

TABLE VIII–2—PARAMETERS LIMITED BY EXISTING ELGS FOR METAL CLEANING WASTE

Wastestream	BPT	BAT	NSPS	PSES	PSNS
Chemical Metal Cleaning Waste.	TSS, Oil & Grease, Copper, Iron.	Copper, Iron	TSS, Oil & Grease, Copper, Iron.	Copper	Copper.
Nonchemical Metal Cleaning Waste.		*Reserved*	*Reserved*	*Reserved*	*Reserved.*

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 solicits comment on the specific generating units that should be included in the exemption. See Section VIII.A.3 for additional details regarding the information that EPA is requesting as part of the comment solicitation.

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. Therefore, as described later in this preamble, EPA is also soliciting comments associated with each generating unit with discharges of nonchemical metal cleaning wastes that are not currently subject to the BPT copper and iron limits, in order to understand the nonchemical metal cleaning wastes that are generated, the characteristics of the wastewater, what actions would be needed to comply with the proposed copper and iron limits, and estimated costs associated with those actions. See Section VIII.A.3 for details regarding the information that EPA is requesting as part of the comment solicitation.

Anti-Circumvention Provisions. 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. EPA requests comment on the extent, if any, to which this provision may discourage water re-use.

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. EPA requests comment on the extent to which this provision may discourage water re-use.

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 [23] for the wastewater being analyzed is at or below the level of the effluent limitation. 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.

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. This action provides notification that EPA is considering establishing BMP requirements to address impoundment construction, operation, and maintenance in the final ELG rule using CWA authority. 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 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

[23] 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.''

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.[24] 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 today 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. EPA requests comment on possible BMPs for inclusion in a final ELG rule including those described above and any other appropriate variations on them.

Voluntary Incentive Program for Power Plants That Close CCR Impoundments or Eliminate All Process Wastewater Discharges (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 today 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 VIII.B) if they also dewater, close and cap all CCR surface impoundments (except for those impoundments containing only combustion residual 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 VI. 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

[24] 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.

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 VIII.B) 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. EPA requests comment on the voluntary incentives program described in this section and any appropriate variations.

3. Rationale for the Proposed Best Available Technology (BAT)

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 VII.B.2, 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 [25];
- Establish BAT effluent limits for bottom ash transport water and

[25] 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.

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 [26 27];

• 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 [28]; 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 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,[29] 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). 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 Sections VI and VIII.A.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 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. See Section 9.7.3 of the TDD.

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 3, 3b (for units located at plants with a total wet-scrubbed capacity of 2,000 MW or more), 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

[26] 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.

[27] For units below the 2,000 MW threshold, BAT would continue to be determined on a site-specific basis.

[28] 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.

[29] 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.

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.[30] Other power plants are considering installing the biological treatment technology to remove selenium and at least one plant is moving forward with construction. See DCN SE03874. 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.

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 (See Section 8.1.3 of the TDD).[31]

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. EPA solicits comment on the proposed 2,000 MW threshold applicable to discharges of FGD wastewater under Option 3b, including whether this or another threshold may be more appropriate.

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 facilities (for example, approximately half of Option 4 costs and approximately a third of Option 5 costs), and, therefore, looked carefully at this wastestream with a particular focus on generating unit size. Our 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

[30] Four of the six operate the biological treatment systems in combination with chemical precipitation.

[31] 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.

generate bottom ash transport water, over 90 percent are 400 MW or less. See DCN SE03834.

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. EPA solicits comment on the proposed 400 MW threshold applicable to discharges of bottom ash transport water under Option 4a, including whether this or another threshold may be more appropriate.

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 being proposed today. 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 these proposed BAT limitations. Also see Section 7.7 of the TDD.

In order to implement the exemption proposed today 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. Any public comments submitted with the intention of identifying generating units that might appropriately fall within the exemption must provide the necessary documentation (e.g., permits, fact sheets) to support a finding that the generating unit meets all three criteria. EPA also requests comment on this general method of implementing the exemption. Another approach 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 requests comment on this, or any other, way of implementing the proposed exemption.

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 discharge of metal cleaning wastes. Therefore, EPA is also soliciting comments that provide information on those generating units that are not currently subject to the BPT metal cleaning waste limitations for copper and iron, in order to understand what actions would be required to comply with the proposed BAT nonchemical metal cleaning waste limitations for iron and copper. EPA is particularly interested in the following information:

- Type of nonchemical metal cleaning waste generated, frequency of generation, and volume generated;
- Wastewater characterization data (i.e., monitoring data) for the nonchemical metal cleaning waste; [32]
- Information regarding the actions that would need to be taken to comply with the iron and copper limits for the nonchemical metal cleaning wastes discharged; and
- Estimated capital and operating and maintenance costs, broken out by specific cost components (e.g., equipment costs, installation costs, labor costs), to comply with the proposed copper and iron limits, along with the basis for the cost estimate.

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.[33] 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.[34] [35] 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 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 XVI, EPA is proposing that, where the limitations and standards being proposed today 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 XV of the preamble and in the TDD. 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 XV.B., 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

[32] Commenters should provide available monitoring data (i.e., EPA is not requiring the commenters to collect additional samples). Additionally, commenters should specify what data are represented by the characterization data (which wastestreams were sampled, the percent contribution of each wastestream, whether the samples are untreated or treated, and if treated, the type of treatment system represented).

[33] IPM is a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. See Section XI for additional discussion.

[34] 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.

[35] 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.

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. Consequently, EPA is interested in receiving information through the public-comment process related to cost, pollutant reduction, and effectiveness data on chemical precipitation and alternative approaches to treatment of 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. Section XIII of the preamble includes additional discussion about discharges of bromides. Also, see the EA.

For the reasons described below in Section VIII.B., EPA is proposing that, where the limitations and standards being proposed today 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.[36] 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

[36] 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.

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 [37], but would not establish BAT effluent limits for TSS and oil and grease (which are also currently regulated by BPT for metal cleaning wastes). EPA's proposal and reasoning is detailed below.

In addition, EPA has identified some differences among the options in terms of cost effectiveness. Section XII of this preamble 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.[38] 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.

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.

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.

Effluent Limits for Small Generating Units. EPA is proposing to establish

[37] 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.

[38] 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.

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.[39] 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[40] rather than 25 MW because the proposed 50 MW threshold would do more to alleviate potential impacts.[41] 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. EPA requests comment on the proposed 50 MW threshold applicable to discharges of the wastestreams described under each of the preferred options, and as well as other possible thresholds for small units.

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 above in Section VII.B.2, EPA is proposing to establish NSPS based on the suite of technologies identified for Option 4 in Table VIII–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.[42] 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 result, do not discharge bottom ash transport water. The Option 4 technologies being proposed today 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

[39] Preferred Option 4a would increase this threshold for purposes of discharges of pollutants in bottom ash transport water only, to 400 MW or less.

[40] 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.

[41] As discussed in Section XVII.C, the proposed 50 MW threshold also alleviates potential impacts which may be borne by small entities or municipalities.

[42] 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.

manages the FGMC wastewater so that it is not discharged to surface waters (or has the capability to do so). For leachate, as discussed above in Section VI, 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 today 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 above in Section XI, 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 and 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 today for existing sources, the proposed NSPS would establish the same limits for oil-fired generating units and small generating units [43] that are being proposed for all other new sources. 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 requests comment on its proposal to establish the same NSPS for small generating units as for larger units.

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 units at 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.[44] 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 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 the TDD and RIA for more information about the estimated

[43] As a point of clarification, this similarly holds true for bottom ash limitations.

[44] This rationale similarly applies to Option 3a.

compliance costs for the NSPS options. Also, see Section XI below. 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. EPA requests comment on its selection of Option 4 instead of Option 5 as the basis for NSPS.

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 VIII–3 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 VIII–3—SUMMARY OF PASS THROUGH ANALYSIS RESULTS

Treatment option	Pollutant	Pass through? (Yes/No)
Chemical Precipitation for FGD Wastewater and/or Leachate	Arsenic	Yes.
	Mercury	Yes.
Biological (chemical precipitation followed by anoxic/anaerobic biological) for FGD Wastewater and/or 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.

For this proposal, EPA evaluated the same model technologies and regulatory options for PSES that it evaluated for BAT (described in Section VIII.A.2). These standards would apply to existing generating units that discharge wastewater to POTWs.

As explained above in Section III.B.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. This proposal is no exception. After considering all of the technology options described in Section VIII.A.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;[45] 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;[46]
- Establish a ''zero discharge'' standard for all pollutants in fly ash transport water and FGMC wastewater;

[45] 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.

[46] 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 CFR 403.5(c)(2).

• Establish standards for copper in discharges of nonchemical metal cleaning wastes;[47] 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 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 VIII.A.3 above 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 XV. Furthermore, for the same reasons that apply to EPA's preferred BAT options and described in Section VIII.A.3, with the exception of numeric standards for copper in discharges of nonchemical metal cleaning wastes,[48] EPA is proposing not to subject discharges from oil-fired generating units and small generating units (i.e., 50 MW or smaller[49]) to POTWs to requirements based on Options 3a, 3b, 3, or Option 4a.

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 XVI.

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 this proposal, EPA evaluated the same model technologies and regulatory options for PSNS that it evaluated for NSPS (described above in Section VIII.A.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 VIII.A.2, as is the case for NSPS, 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 VIII.A.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.[50] 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 XV.

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[51] and the associated costs of

[47] 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.

[48] 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.

[49] Preferred Option 4a would increase this threshold for purposes of discharges of pollutants in bottom ash transport water only, to 400 MW or less.

[50] For the same reasons discussed above in Section VIII for NSPS, EPA similarly determined the other regulatory options do not reflect PSNS.

[51] 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

complying with these proposed regulatory requirements for the wastewater that may result from the forecasted air control installations. The sensitivity analysis and results are described in more detail in DCN SE01989.

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;[52] 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 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 this proposal 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 this proposed rule by no more than 10 to 15 percent. See discussion in Section VII.A.7. 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. 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 VIII.A.2, EPA proposes that certain BAT limitations for existing sources being proposed today (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

to comply with existing federal and state requirements.

[52] EPA IPM v.4.10 projections for units based on compliance with CSAPR, MATS, state rules, and enforcement actions including consent decrees.

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 system, 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 this 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 this proposal 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.

IX. Technology Costs and Pollutant Reductions

This section provides an overview of EPA's approach for estimating the compliance costs and pollutant reductions associated with the regulatory options discussed in this proposal. Sections 9 and 10 of the TDD provide a much more in depth discussion of these analyses.

EPA often estimates costs and pollutant loads on a per plant basis and then sums or otherwise escalates the plant-specific values to represent industry-wide compliance costs and pollutant reductions. Calculating costs and loads 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., BMPs and end-of-pipe treatment). EPA took this approach in estimating the compliance costs and pollutant reductions associated with this 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 this proposal on all plants currently subject to the existing ELGs. Some aspects of this proposal (e.g., applicability changes) would likely not lead to increased costs to complying facilities. Other aspects of this proposal would likely lead to increased costs to a subset of complying facilities. These facilities are generally those that generate and discharge the wastestreams for which EPA is proposing new limitations or standards. EPA reviewed the steam electric industry for all facilities that generate the specific types of wastewater streams for which EPA evaluated additional limitations or standards. The following describes the detailed costing and loadings evaluation EPA performed for these plants.

As discussed earlier in this preamble, 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, EPA is proposing to establish BAT limitations that would be set equal to BPT limitations. Since this proposed rule would not establish additional control on discharges associated with these operations, there would be no incremental costs for these units to comply with the requirements of this proposed rule.[53]

For the aspects of these proposed regulatory options that include limitations and standards for additional pollutants, EPA estimated compliance costs and pollutant reductions 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 and pollutant loadings models for each of the technologies that form the basis of the regulatory options. EPA used these models to calculate facility-specific compliance costs and pollutant reductions for all power plants that the information suggests may incur costs to comply with one or more proposed limitations or standards associated with the regulatory options.[54] [55] Therefore,

[53] EPA did estimate costs for these existing oil-fired generating units and small generating units to comply with the options considered in this rulemaking and has included those estimates in the docket for the proposed rule (see DCN SE01957, *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category*).

[54] Because EPA anticipates taking final action on this rulemaking in 2014, EPA did not include plants that are expected to retire by 2014 and plants that do not discharge any of the applicable wastestreams. Since this timeframe is approximately one year following the date of the proposed rule, EPA considers there to be sufficient certainty regarding plant/unit retirements or relevant major system modifications for it to be reasonable for EPA to take into account in the regulatory analyses for this rulemaking, Retirements and modifications occurring farther into the future than 2014 become more uncertain and subject to change; thus, EPA has considered such future changes, as appropriate, in sensitivity analyses for proposed rule. However, this approach can result in estimating compliance costs for generating units that companies have announced will retire, repower, or convert from wet to dry ash handling. Because of this, EPA is considering using alternative dates, such as 2022 which may better reflect the implementation timeframe for the ELG, for the baseline year for its analyses for the final rule.

EPA's plant-specific cost and pollutant reduction estimates represent the incremental costs/pollutant reductions for a plant when its existing practices would not lead to compliance with the option being evaluated for the proposed rule. While plants would not be required to implement the specific technologies that form the basis for the proposed limitations and standards for each of the regulatory options, EPA calculated the cost and associated pollutant reductions for plants to implement these technologies to estimate the compliance costs and pollutant loading reductions associated with EPA's proposed rule.

EPA's cost estimates include two key cost components: Capital costs (one-time costs) and operating and maintenance (O&M) costs (which are incurred every year). 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, land, site preparation, engineering costs, construction expenses, contractor's fees, and contingency. Annual O&M costs comprise all costs related to operating and maintaining the pollution control technologies or performing BMPs for a period of one year. O&M costs are also specific to the industry and commonly include costs associated with operating labor, maintenance labor, maintenance materials (routine replacement of equipment due to wear and tear), chemical purchase, energy requirements, residual disposal, and compliance monitoring. In some cases, the technology options may also result in recurring costs that are incurred less frequently than annually (e.g., 3-year recurring costs) or one-time costs other than capital investment (e.g., one-time engineering costs).

A. Methodology for Estimating Plant-Specific Costs

The limitations and standards associated with the regulatory options for this proposed rule address various wastestreams and, as such, consist of multiple technology bases (see Table IX–1). As a first step in estimating costs to control discharges associated with a particular generating unit at an existing steam electric power plant subject to this rulemaking (i.e., existing sources), EPA used the plant's survey response to determine if the wastestreams it discharges may be affected by the limitations and standards for the regulatory options considered in this rulemaking. Then, for each of the wastestreams that may be affected by an option, EPA reviewed the industry survey response, available sampling data, and industry long-term self-monitoring data to determine if the plant currently meets the performance level of the technology basis for the requirement of an option for that wastestream. A portion of the steam electric industry has already implemented processes or treatment technologies that serve as the basis for the regulatory options considered for the proposed rule; as a result, these facilities would not incur costs to comply with the proposed rule, or would incur costs lower than they would be if the processes/technologies had not already been implemented. In such cases, EPA assigned 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. Table IX–2 presents a list of the major cost components included in the evaluation. 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.

TABLE IX–1—TECHNOLOGY COST MODULES USED TO ESTIMATE COMPLIANCE COSTS

Wastestream	Technology cost modules	Regulatory option							
		1	3a	2	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 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
Other Plant-Level Costs									
	Solids Transportation	X	X	X	X	X	X	X	X
	Solids Disposal	X	X	X	X	X	X	X	X
	Impoundments	X	X	X	X	X	X	X	X
	Compliance Monitoring	X	X	X	X	X	X	X	X

[55] EPA is considering establishing BMPs that would apply to surface impoundments 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. Costs for the industry to implement the BMPs under consideration are included in EPA's cost and economic analyses for the proposed rule.

TABLE IX–2—MAJOR CAPITAL COST COMPONENTS INCLUDED IN COMPLIANCE COSTS

Technology module	Major capital cost components
Chemical Precipitation	• Equalization tank; • Reaction tanks; • Chemical feed systems; • Solids contact clarifier; • Sand filters; • Treated wastewater tank; • Sludge filter press; and • Sludge holding tank.
Biological Treatment	• Bioreactor tanks; • Nutrient feed system and storage; • Backwash system and backwash wastewater tank; and • Heat exchangers (if needed).
Vapor-Compression Evaporation	• Water softener; • Brine concentrator; and • Forced-circulation crystallizer.
Conversion of Wet Fly Ash Handling to Dry Vacuum Fly Ash Handling	• Conveyance Vacuum Line Components (i.e., valves, piping, couplings); • Filter-Receiver; • Vacuum Pumps; • Lot miscellaneous instrumentation and control; • Steel or concrete silo; • Silo Instrumentation and Aeration System; and • Pugmill unloaders.
Conversion of Wet Bottom Ash Handling to Mechanical Drag System (MDS) or Remote MDS.	• Water bath trough; • Chain conveyor; • Inclined conveyor; • Storage silo; • Remote MDS only: collection sump, chemical feed system, and recirculation pumps.
Transportation	• Only operating and maintenance cost components
Disposal	• On-Site Disposal: • Landfill expansion construction • Leachate treatment system • Groundwater wells • Closure cap • Off-Site Disposal: no capital cost components
Compliance Monitoring	• Only operating and maintenance cost components

For example, to comply with BAT regulatory Option 4 presented in this proposal, 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 assumed that certain components of its existing system would continue to be used following the conversion.[56] 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, EPA estimated compliance costs to comply with BAT regulatory Option 4 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 included 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 clarification, sand filtration, effluent and sludge holding tanks, sludge filter press, 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.

Following the evaluation of treatment in place, EPA estimated plant and wastestream specific incremental costs using computerized design and cost models. For the applicable wastestreams, the models provide capital, annual O&M, one-time, and 3-, 5-, 6-, and 10-year recurring costs for implementing and using the applicable technology basis. EPA developed cost equations from responses to the industry survey, published information, vendor contacts, and engineering judgment. EPA developed the following cost modules:

- One-Stage Chemical Precipitation—calculates capital and O&M costs associated with a one-stage chemical precipitation system;
- Biological Treatment—calculates capital and O&M costs associated with an anoxic/anaerobic biological treatment system;
- Vapor-Compression Evaporation—calculates capital and O&M costs associated with a vapor-compression evaporation system;
- Dry Fly Ash Handling—calculates capital, O&M, and recurring costs associated with a dry fly ash handling system;

[56] 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.

- Dry Bottom Ash Handling—calculates capital, O&M, and recurring costs associated with a dry bottom ash handling system;
- Transportation—calculates O&M costs associated with transporting FGD, ash, and/or landfill leachate solid waste to an on-site 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-site or off-site landfill; and
- Impoundment Costs—calculates capital, O&M, and recurring costs associated with the operation and maintenance of an on-site impoundment.

Ultimately, the cost model produces a plant-level summary of the incremental technology option costs associated with each regulatory option. Each plant incurring a cost for an evaluated wastestream is presented in the output. To determine the total compliance cost for a plant associated with a regulatory option, EPA calculated the various cost components described above for each applicable wastestream. EPA then summed the costs for each component of each wastestream to calculate the total capital, O&M, and other recurring costs for the plant. Section XI of this preamble and the RIA contains a more detailed discussion of EPA's annualization of the compliance costs.

EPA also 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 the plant would have installed in the absence of the proposed new source requirements. EPA estimated capital and O&M costs for several scenarios that represent the different types of operations that are present at existing units at existing power plants or are typically included at new power plants. These scenarios captured differences in the plant status (i.e., building a unit at a new location versus adding a new unit at an existing power plant), presence of on-site impoundments or landfills, type of ash handling, type of FGD systems in service, and type of leachate collection and handling.

Finally, EPA recognizes there are significant drivers including federal, state, and local requirements for future air control installations at existing units. As such, EPA also conducted a sensitivity analysis that forecasts future installations of air controls through 2020 [57] and the associated costs of the regulatory options discussed in this proposal. EPA estimated these installations using data reported by individual plants in the survey regarding planned installations, as well as analyses conducted by OAR using the IPM, which is widely used by EPA for analysis of rules and policies affecting electric power generating facilities. Section VIII.A.7 contains a discussion of EPA's approach for forecasting future installations. EPA then estimated plant-specific costs for these future installations, using the same approach as it used for current operations.

B. Methodology for Estimating Plant-Specific Pollutant Reductions

EPA took a similar approach to the one described above for costs in estimating pollutant reductions associated with the limitations and standards for the regulatory options in this proposal. That is, EPA estimated incremental pollutant reductions for discharges of a particular wastestream at a particular plant when its existing practices would not lead to compliance with the option being evaluated. In such cases, EPA estimated the annual pollutant (baseline) load associated with the current discharge of a wastestream and the post-compliance annual pollutant load expected after implementation of the applicable technology basis. EPA then calculated the pollutant loading reduction at a particular plant as the sum of the difference between the estimated baseline and post-compliance discharge load for each applicable wastestream.

The following provides a brief discussion of the methodology EPA used to estimate baseline loads discharged for the various wastestreams. For those plants that discharge indirectly to POTWs, EPA adjusted the baseline loads to account for pollutant removals expected from POTWs. These adjusted pollutant reductions for indirect dischargers reflect reductions in discharges to receiving waters.

1. FGD Wastewater

For FGD discharges, EPA estimated 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 wastestream to one of four classes of treatment: surface impoundment, chemical precipitation, anaerobic/anoxic biological treatment, and vapor-compression evaporation. EPA identified the plant's current treatment system using data reported in the industry survey. Of the 117 plants that discharge FGD wastewater, 40 operate chemical precipitation systems, six operate biological treatment systems, and two operate a vapor-compression evaporation system.[58] All other plants are categorized in the surface impoundment class of treatment.

EPA then estimated the average baseline pollutant effluent concentration of each analyte for each class of treatment. EPA used data collected in its sampling program to characterize effluent concentrations from chemical precipitation, anoxic/anaerobic biological treatment, and vapor-compression evaporation systems. Because EPA lacked data on pollutant effluent concentrations associated with FGD wastewater impoundments, EPA estimated that surface impoundments remove particulate matter (including the particulate phase metals) to an equivalent treatment level of 30 mg/L TSS (i.e., thus assuming that the discharge would be in compliance with the current BPT effluent limits for low-volume waste sources). EPA estimated that all dissolved metals will pass through the surface impoundment and be discharged. Section 10 of the TDD contains more information on baseline pollutant effluent concentrations.

EPA then used this average baseline pollutant effluent concentration with plant-specific discharge flow rates reported in the industry survey to estimate the mass pollutant discharged per plant.[59] Section 9 of the TDD contains more details on how EPA developed flow rates.

For post-compliance FGD pollutant loading concentrations, for each pollutant, EPA used the long-term average for the technology basis for the option being evaluated. With a few exceptions, EPA then used these pollutant concentrations in combination with the same plant-specific discharge flow rates it used for baseline. The exceptions are five plants currently discharging FGD wastewater that EPA predicts will incorporate recycle within the FGD system based on the maximum operating chlorides concentration compared to the design maximum chlorides concentration.

[57] EPA expects that plants will be in compliance with new federal and state air pollution control requirements by 2020.

[58] A third power plant is currently installing a vapor-compression evaporation system to treat the FGD wastewater.

[59] In some cases, plant-specific discharge flow rates were not available in the survey response. See Section 9 of the TDD for more information on how EPA estimated flow rates.

2. Fly Ash and Bottom Ash

For baseline ash loads, EPA used publicly available data to characterize discharges from ash impoundments, including data collected during EPA's Detailed Study, EPRI PISCES reports, permit application data, and the 1982 *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). EPA used the concentration data obtained from these sources to calculate the average pollutant concentration in fly ash, bottom ash, and combined ash impoundments. EPA then coupled these concentrations with plant-specific ash sluice rates reported in the industry survey to calculate baseline ash discharge loads. In cases where EPA had available information regarding recycle associated with the impoundment overflow, EPA adjusted the sluice rates to reflect the discharge flow rate from the impoundment. For post-compliance pollutant loadings, EPA assumed implementation of dry ash handling would result in a zero post-compliance load.

3. Combustion Residual Leachate

For baseline leachate loads, EPA used data reported in Part G of the industry survey to calculate an average baseline pollutant concentration for leachate. These data included responses from 22 active fuel combustion residual landfills and four inactive fuel combustion residual landfills. EPA then used the baseline pollutant concentrations in conjunction with leachate flow rates to calculate the baseline pollutant loadings. Section 9 of the TDD describes how EPA used industry survey data to estimate leachate flow rates. For post-compliance leachate loads, EPA lacked data on effluent concentrations from chemical precipitation or biological treatment of leachate from combustion residual landfills or surface impoundments. EPA is proposing the effluent limits for leachate discharges would be based on transferring the effluent limits calculated for FGD wastewater using the identical technology bases. Therefore, EPA estimates, based on engineering judgment, that post-compliance effluent concentrations for leachate would be equal to the average effluent FGD wastewater concentrations for a similar treatment technology.

4. FGMC and Gasification Wastewaters and Nonchemical Metal Cleaning Wastes

FGMC wastewater originates from activated carbon injection systems. EPA identified 73 plants with current or planned activated carbon injection systems. Most of these plants use, or plan to use, a dry handling system to transfer the mercury-containing carbon to silos for temporary storage until the waste is hauled away by trucks for disposal in a landfill. EPA identified only six plants that transport (sluice) FGMC waste with water to a surface impoundment. However, five of these six plants do not discharge any FGMC wastewater and the remaining plant has the capability to handle the FGMC waste using a dry system but sometimes uses a wet system instead. Since the current baseline discharge of pollutants for FGMC wastewater is essentially zero, the proposed rule would establish effluent limitations that are consistent with the current industry practices for FGMC wastewater (i.e., zero discharge) and therefore EPA estimates there will be no (or little) incremental removal of pollutants relative to current practices. At the same time, however, establishing the proposed zero discharge standard for FGMC wastewater will ensure that future FGMC installations implement dry waste handling practices or manage wastewater in a manner that achieves zero discharge of pollutants.

The two IGCC plants currently operating in the United States already use the technology that is the basis for all eight regulatory options for gasification wastewater. A third IGCC plant that will soon begin commercial operation will also use this same treatment technology. Since these plants are already operating the technology that serves as the basis for the proposed BAT, the proposed rule would establish effluent limitations that are consistent with the current industry practices for gasification wastewater and, therefore, EPA estimates there will be no incremental removal of pollutants relative to current practices.

The proposed ELGs for discharges of nonchemical metal cleaning waste are equal to the current BPT effluent limits for metal cleaning waste. The proposed requirements are based on the same technology that was used as the basis for the current ELGs requirements for chemical metal cleaning waste. Since, as described above in Section VIII, nonchemical metal cleaning waste is included within the definition of metal cleaning waste, EPA would be establishing ELGs that are equal to the BPT limits that already apply to discharges of these wastes to surface waters.[60] Additionally, as described in Section VIII.A.3, EPA is proposing to exempt from new copper and iron limitations and standards any existing nonchemical metal cleaning wastes generated and currently 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; therefore, no facilities would incur incremental costs to comply with the proposed ELGs for these wastes, nor would there be incremental pollutant removals associated with the proposed ELGs.

5. Request for Comment on Data

While EPA is soliciting comment on all aspects of this proposal, the Agency would like to highlight certain aspects related to the pollutant removal estimates. EPA solicits additional data or information on pollutant loadings in steam electric power plant wastewater discharges that would corroborate or correct the data used in EPA's analysis, including data or information relating to the pollutants of concern that EPA has identified in this rulemaking. It is important that EPA have data and information of sufficient quality in order to incorporate the data into its analysis. If you have data or information or you intend to collect data that you believe would be relevant to EPA and you would like to submit the data as part of your public comments, EPA encourages you to contact the Agency first to ensure that the data submitted contains sufficient and relevant information, and that it is provided in an appropriate format, such that it can inform EPA's analyses for the final action (see points of contact in the introduction to this preamble).

EPA is also seeking comment related to the data used in developing this proposed rule and how it should be analyzed: age of data, treatment of non-detects, treatment of pollutants in the source water and the calculation of toxic-weighted pollutant equivalents.

Age of data. How should EPA take into account changes that may have occurred in the industry over time and what information would be appropriate for demonstrating that certain data for certain pollutants or wastestreams should or should not be used? For

[60] The proposed BAT would establish limits for copper and iron equal to the existing BPT limits for these pollutants. The proposed NSPS would establish standards for copper, iron, TSS, and oil and grease that are equal to the BPT limits for these pollutants. The proposed PSES and PSNS would establish standards for copper equal to the BPT limits for copper. See Section VIII for details about the proposed limitations for nonchemical metal cleaning wastes.

example, should EPA use a date cutoff for the data used and what rationale should be used for any such cutoff? EPA encourages commenters to submit any more recent data (but you should contact EPA first to make sure the data you submit is usable for the analyses, see above).

Treatment of non-detect values. How should EPA treat non-detects in effluent data when determining baseline pollutant loadings? What other information should inform how EPA handles the issue of non-detects, given that in some cases, analytical methods cannot determine the actual amount of pollutants in wastewater? Should EPA use a cutoff for the number or percentage of non-detects in a dataset in order for EPA to use the dataset for a specific pollutant? For example, there were more non-detects than detected values for effluent data for sulfides. Does this dataset provide a sufficient basis, in the absence of any other information, for estimating pollutant loadings for sulfides?

Treatment of pollutants in the source water. When should EPA adjust pollutant loadings concentrations to account for contributions from a facility's source water? Should EPA estimate pollutant loadings for pollutants for which a certain percentage of the influent concentration comes from source water? If EPA were to do this, what steps should the Agency take to ensure the adjustments for source water contribution definitively link the source water data to the influent and effluent data?

Calculation of toxic-weighted pollutant equivalents. Is EPA's calculation of TWPEs appropriate? Do commenters have suggestions, either generally or relative to specific pollutants, for how this calculation can be improved?

C. Summary of National Engineering Costs and Pollutant Reductions for Existing Plants

As described above in Section VIII, EPA evaluated eight regulatory options comprised of various combinations of the technology options considered for each wastestream, summarized in Table VIII–1. The Agency estimated the costs and pollutant loading reductions associated with steam electric power plants to achieve compliance with each regulatory option under consideration. This section summarizes the total estimated compliance costs and pollutant reductions associated with each option for existing plants (see Tables IX–3 and IX–4). These tables present the capital cost, annual operating and maintenance costs, one-time costs, and recurring costs for each regulatory option. Section XI contains 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 shown in Section XI take into account the timeframe proposed to meet the limits in the rule.

Information, including plant-specific information, for EPA's compliance cost and pollutant loading estimates and methodologies is located in the rulemaking record. Some of the information EPA used to estimate compliance costs and pollutant loadings was claimed by survey respondents as CBI. Therefore, this information is not included in the public docket. However, the public docket contains a number of documents that set forth EPA's methodology, assumptions and rationale for developing its cost estimates and pollutant loadings estimates, and that also present as much data as possible by using aggregation, summaries, and other techniques to protect CBI. EPA encourages all interested parties to refer to the record and to provide comments where appropriate on any aspect of the methodology or the data used to estimate compliance costs and pollutant loadings associated with this proposal.

TABLE IX–3—COST OF IMPLEMENTATION (BAT AND PSES)

[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)
3b	80	998	244	0	0	0	1	(26)
3	155	2,897	434	0	0	0	10	(54)
4a [a]	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)

[a] EPA estimated the costs for Option 4a based on approximated plant-level bottom ash costs 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. For more details on how EPA estimated these plant-level bottom ash costs, see the memorandum entitled "Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a" (DCN SE03834).

TABLE IX–4—ESTIMATED POLLUTANT LOADING REDUCTION (BAT AND PSES)

[In million pounds/year]

Regulatory option	Pollutant removals		
	Conventional pollutants [a]	Priority pollutants	Nonconventional pollutants [b]
1	2.8	0.5	[c] (418)
3a	16	0.4	468
2	2.8	0.7	1,155
3b	17.1	0.6	914
3	19	1.1	1,623
4a [d]	28	1.4	2,612
4	35	1.7	3,328

TABLE IX–4—ESTIMATED POLLUTANT LOADING REDUCTION (BAT AND PSES)—Continued

[In million pounds/year]

Regulatory option	Pollutant removals		
	Conventional pollutants [a]	Priority pollutants	Nonconventional pollutants [b]
5	36	1.7	5,287

[a] The loadings reduction for conventional pollutants includes BOD and TSS. Note that the BOD and TSS removals are not included in the total pollutant removals stated in Section II (1.63 billion pounds per year for Option 3; 3.34 billion pounds per year for Option 4) to avoid double-counting removals for certain priority and nonconventional pollutants that would also be measured by these bulk parameters.

[b] The loadings reduction for nonconventional pollutants excludes TDS and COD to avoid double-counting removals for certain pollutants that would also be measured by these bulk parameters (e.g., sodium, magnesium).

[c] Option 1 shows a negative removal for nonconventional pollutants because the mass of several pollutants (ammonia, chromium, TKN, and BOD) are not quantified at baseline, and because some pollutant discharge concentrations are higher under Option 1.

EPA estimated the pollutant removals for Option 4a based on approximated plant-level bottom ash loadings 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. For more details on how EPA estimated these plant-level bottom ash loadings, see the memorandum entitled ''Methodologies for Estimating Costs and Pollutant Removals for Steam Electric ELG Regulatory Option 4a'' (DCN SE03834).

X. Approach To Determine Long-Term Averages, Variability Factors, and Effluent Limitations and Standards

This section describes the statistical methodology used to calculate the long-term averages, variability factors, and limitations for BAT, new source performance standards and pretreatment standards for existing and new sources. The effluent limitations and standards are based on long-term average effluent values and variability factors that account for variation in treatment performance of the model technology.

The proposed effluent limitations and/or standards, collectively referred to in the remainder of this section as ''limitations,'' for pollutants for each technology option, as presented in this notice, are provided as ''daily maximums'' and ''maximums for monthly averages.'' Definitions provided in 40 CFR 122.2 state that the daily maximum limitation is the ''highest allowable 'daily discharge,''' and the maximum for monthly average limitation is the ''highest allowable average of 'daily discharges' over a calendar month, calculated as the sum of all 'daily discharges' measured during a calendar month divided by the number of 'daily discharges' measured during that month.'' Daily discharges are defined to be the '''discharge of a pollutant' measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling.'' In this section, the term ''option long-term average'' and ''option variability factor'' are used to refer to the long-term averages and variability factors for technology options for an individual wastestream rather than the regulatory options described in Section VIII.

A. Criteria Used To Select Data as the Basis for the Limitations and Standards

In developing effluent limitations guidelines and standards for any industry, EPA qualitatively reviews all the data before selecting data that represents proper operation of the technology that forms the basis for the limitations. EPA typically uses four criteria to assess the data. The first criterion requires that the plants have the model treatment technology 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. As a result of this review, 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).

A second criterion generally requires that the influents and effluents from the treatment components represent typical wastewater from the industry, without incompatible wastewater from other sources. Application of this criterion results in EPA selecting those plants where the commingled wastewaters did not result in substantial dilution, unequalized slug loads resulting in frequent upsets and/or overloads, more concentrated wastewaters, or wastewaters with different types of pollutants than those generated by the wastestream for which EPA is proposing effluent limitations.

A third criterion typically ensures that the pollutants are present in the influent at sufficient concentrations to evaluate treatment effectiveness. To evaluate whether the data meet this criterion for inclusion as a basis of the limitations, EPA often uses the long-term average test (or LTA test) for plants where EPA possesses paired influent and effluent data (see Section 13 of the Technical Development Document for details of the LTA test). The test measures the influent concentrations to ensure a pollutant is present at a sufficient concentration to evaluate treatment effectiveness. If a dataset for a pollutant fails the test (i.e., pollutant not present at a treatable concentration), EPA excludes the data for that pollutant at that plant when calculating the limitations.

A fourth criterion typically requires that the data are valid and appropriate for their intended use (e.g., the data must be analyzed with a sufficiently-sensitive method). Also, EPA does not use data associated with periods of treatment upsets because these data would not reflect the performance from well-designed and well-operated treatment systems. In applying the fourth criterion, EPA may evaluate the pollutant concentrations, analytical methods and the associated quality control/quality assurance data, flow values, mass loading, plant logs, 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 initial commissioning period for treatment systems. Most industries incur commissioning periods during the adjustment period associated with installing new treatment systems. During this acclimation and optimization process, the effluent concentration values tend to be highly variable with occasional extreme values (high and low). This occurs because the treatment system typically requires some ''tuning'' 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.[61]

B. Data Used as Basis of the Limitations and Standards

The sections below discuss the data used as the basis for this proposal, including data selection, the combination of data from multiple sources within each plant, and the data exclusions made prior to calculate the limitations.

1. Data Selection for Each Technology Option

This section describes the data selected for use in developing the limitations for each technology option. This section includes an abbreviated description of the technology options. See Section VIII for a more complete discussion of the technology basis for each of the options considered. For fly ash transport water and 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. This is also true for the options that include zero discharge of pollutants for any set of dischargers for bottom ash.

Except as described in Section VIII, EPA is proposing to establish limitations for discharges of pollutants in nonchemical metal cleaning wastes 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. See Section VIII for a more complete discussion of the basis for the proposed limitations.

Under some regulatory options being proposed today, EPA would establish limitations for certain wastewater discharges that are equal to the current BPT limitations for those discharges. 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 VIII for a more complete discussion of the basis for the proposed regulatory options. For the limitations for combustion residual leachate (hereafter referred to in this section as leachate) based on the chemical precipitation technology option, EPA is proposing to transfer the limitations calculated based on the chemical precipitation technology option for the FGD wastewater because EPA does not have the available effluent data for leachate from plants that employ the chemical precipitation technology. For the limitations based on the biological treatment technology option for FGD wastewater, EPA is proposing to transfer the limitations for two pollutants (mercury and arsenic) calculated based on the chemical precipitation technology option for the FGD wastewater for the reasons described below. See Section 13 of the Technical Development Document for a detailed discussion on the transfer of limitations for leachate and FGD wastewater.

EPA used specific data sources to derive limitations for pollutants in FGD and gasification wastewater discharges based on particular treatment technology. The data sources used to calculate limitations for each technology option, by wastestream, are described below.

a. 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 systems. 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.[62] 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 VIII above for a more detailed description):

[61] 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.

[62] 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.

- Duke Energy's Miami Fort Station (''Miami Fort'');
- RRI Energy's Keystone Generating Station (''Keystone''); and
- Allegheny Energy's Hatfield's Ferry Power Station (''Hatfield's Ferry'').

For the treatment of FGD wastewater using a system that includes biological treatment as part of the process, EPA evaluated the treatment systems at three power plants as part of the EPA sampling program; however, one of the biological treatment systems was not designed for effective removal of selenium and does not represent the model technology. The biological treatment technology option is based on a 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, followed by anoxic/anaerobic biological treatment designed to remove selenium, hereafter referred to in this section as ''biological treatment''—see Section VIII above for a more detailed description. EPA used data from the following two plants to develop the limitations for the treatment of FGD wastewater using a one-stage chemical precipitation system followed by biological treatment:

- Duke Energy Carolina's Belews Creek Steam Station (''Belews Creek''); and
- Duke Energy Carolina's Allen Steam Station (''Allen'').

While these two plants operate the biological treatment system included as the basis for the technology option, neither of these plants include sulfide precipitation in the upstream chemical precipitation system and rely only on hydroxide precipitation. Therefore, the effluent mercury and arsenic concentrations achieved by these plants do not fully represent the effluent concentrations that would be achieved by the system used as the design basis for the technology option. For this reason, EPA is proposing to establish the mercury and arsenic limitations for the biological treatment technology option (which includes one-stage chemical precipitation as an initial treatment stage) based on transferring the limitations that were calculated for the chemical precipitation treatment technology option. This is a reasonable approach for establishing mercury and arsenic limitations for the biological treatment technology option because, in doing so, EPA would be setting the limitations equal to the performance that reflects the level of treatment that would be achieved by the initial treatment stage of the wastewater treatment system.

For the treatment of FGD wastewater using a chemical precipitation followed by vapor-compression evaporation system hereafter referred to in this section as ''vapor-compression evaporation'' (which is the technology serving as the basis for regulatory Option 5, which is not a preferred option in this proposal), 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. 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 thus was not used for the limitations development. This plant operates a solids removal process prior to the vapor-compression evaporation system but does not include 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.

b. 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 (''Polk''); and
- Wabash Valley Power Association's Wabash River Station (''Wabash River'').

Both systems are representative of the system used as the basis for the technology option and were used in calculating the limitations.

2. 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 previous effluent guidelines rulemakings, where appropriate, EPA has analyzed the data for each time period 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's sampling and plant self-monitoring data) from a plant during the same time period, EPA combines the data from these sources into a single dataset for the plant for the statistical analysis.

For this rulemaking, data at most selected plants came from multiple sources (EPA's sampling, plant sampling as directed by the EPA through 308 letters, or plant self-monitoring). For some plants, EPA has data collected from multiple sources during overlapping time periods. For these plants, EPA combined the multiple sources of data at each plant into a single dataset for the plant, which provided the basis for developing the limitations. Other plants had data collected from multiple sources 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 data set for the plant, which provided the basis for developing the limitations. Finally, a couple of plants 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 DCN SE02002, ''Sampling Data Used as the Basis for Effluent Limitations for the Steam Electric Rulemaking.''

3. Data Exclusions

Following EPA's selection of the model plant(s), EPA applied the criteria described above in Section A by thoroughly evaluating all available data for each model plant. EPA identified certain data that warranted exclusions from the calculations of the limitations because: (i) The 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 the initial commissioning period for the treatment system; (iii) or analytical results were identified as questionable due to quality control issues, abnormal conditions or treatment upsets, or were analytical anomalies. See DCN SE01999 for a detailed discussion of the data excluded.

C. Overview of the Limitations and Standards

The sections below describe EPA's objectives for proposing the daily maximum and monthly average limitations and the selection of percentiles for those limitations.

1. Objective

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 occasionally 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 limitation, 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.

2. Selection of Percentiles

EPA calculates 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 99th percentile of the distribution of the *daily* measurements. The monthly average limitation is an estimate of the 95th percentile of the distribution of the *monthly* averages of the daily measurements. The percentiles for both types of limitations are estimated using the products of long-term averages and variability factors. EPA has consistently used the 99th percentile as the basis of the daily maximum limitation and 95th percentile as the basis of the monthly average limitation in establishing limitations for numerous industries and for many years and numerous courts have upheld EPA's approach.

EPA uses the 99th and 95th 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 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 proposed effluent limitations. See Section F below for details of these comparisons for each pollutant at each plant, as well as a discussion of the findings of the engineering review.

D. Calculation of the Limitations and Standards

Effluent limitations and standards are based on a combination of the long-term average and 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 factors 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 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 adjustments for autocorrelation in calculating the limitations for each pollutant proposed for regulation.

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[63] values by fitting a statistical model to the daily effluent 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 plant-specific long-term average. In these cases, the plant-specific long-term average for each pollutant was the arithmetic mean of the available daily effluent concentration values. Appendix B of the Technical Development Document 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

[63] For the purpose of discussing 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. Thus, values described in this section as ''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).

(where m=(n+1)/2 and n=number of values). If there is 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.

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 effluent concentration values. Each plant-specific daily variability factor for each pollutant is the estimated 99th percentile of the distribution of the daily pollutant concentration values divided by the plant-specific long-term average. Each plant-specific monthly variability factor for each pollutant is the estimated 95th percentile of the distribution of the 4-day average pollutant concentration values divided by the plant-specific long-term average. The calculation of the monthly variability factor assumes that the monthly averages are based on the pollutant being monitored weekly (approximately four times each month). In cases when there were not enough distinct detected values for a specific pollutant at a plant, then the statistical model was not used to obtain the plant-specific 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 of the Technical Development Document 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 variability factors. The option daily variability factor for a pollutant was found 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 limitation for each pollutant was the product of the option long-term average and option daily variability factor. The monthly average limitation for each pollutant was the product of the option long-term average and option monthly variability factor.

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 may 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 a reliable 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 DCN SE02001 for details of the statistical methods and procedures 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. Also, see Section 13 of the TDD.

E. Long-Term Average, Variability Factors, and Limitations for Each Treatment Option

Due to routine variability in treated effluent, a power plant that discharges consistently at a level near the values of the daily maximum limitation or the monthly average limitation may experience frequent values exceeding the limitations. For this reason, EPA recommends that power plants design and operate the treatment system to achieve the option long-term average for the model technology. Thus, a system that is designed to represent the BAT level of control will be capable of complying with the limitations. The table below provides the proposed long-term average, variability factors, and limitations for each of the FGD, gasification, and leachate treatment technology options. See DCN SE01999 for details of the calculation of the results presented in the table below.

TABLE X–1—PROPOSED LONG-TERM AVERAGES, VARIABILITY FACTORS, AND EFFLUENT LIMITATIONS FOR EACH OF THE FGD, GASIFICATION, AND LEACHATE TREATMENT TECHNOLOGY OPTIONS

Treatment technology	Pollutant	Option LTA	Daily variability factor	Monthly variability factor	Daily limitation [d]	Monthly limitation [d]
Chemical Precipitation for FGD.	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.	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 (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.	Arsenic (ug/L)	[b] 4.0	([c])	([c])	[e] 4	([f])
	Mercury (ng/L)	17.788	2.192	1.338	39	24
	Selenium (ug/L)	[b] 5.0	([c])	([c])	5 [e]	([f])
	TDS (mg/L)	14.884	3.341	1.572	50	24
Vapor-Compression Evaporation for Gasification.	Arsenic (ug/L)	[b] 4.0	([c])	([c])	[e] 4	([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.	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 long-term average, option variability factors, and limitations were transferred from chemical precipitation treatment technology option.
[b] Long-term average is the arithmetic mean since all observations were non-detected.

[c] All observations were non-detected, so the 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 limitation is not established when the daily maximum limitation is based on the detection limit.

F. Engineering Review of Limitations and Standards

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. EPA performed two types of comparisons. First, EPA compared the limitations to the effluent data used to develop the limitations. Second, EPA compared the limitations to the influent data. Sections below summarize the results of these comparisons. For a detailed discussion of the results, see Section 13 of the Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD)—EPA 821–R–13.

1. Comparison of Limitations to Effluent Data Used As the Basis for the Limitations

As part of its data evaluations, EPA compared 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. As part of this evaluation, for each pollutant proposed to be regulated under a technology option, EPA first compared the daily limitations to the daily effluent values. EPA then compared the monthly limitations to all the effluent daily values in a month, and identified those months where at least one value exceeded the monthly 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 proposed 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 limits themselves), it will be able to comply with the limitations.

However, EPA notes that some of the daily effluent values for the BAT plants used to calculate the limitations were found to exceed either the daily or monthly average effluent limitations. See Section 13.9.1 of the TDD for a detailed discussion of the comparison of the limitations and the effluent values, including a discussion of those effluent values that exceed the limitations. EPA solicits comment on this evaluation and EPA's conclusion that plants with a properly designed and operating treatment system would be able to comply with the limitations.

2. Comparison of the Limitations to Influent Data

In addition to comparing the proposed limitations to the data used to develop the limitations, EPA also compared the value of 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.

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 (see DCN SE01999). Thus, EPA determined that facilities 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 system 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.

EPA expects that facilities will comply with their effluent limitations at all times. If the exceedance is caused by an upset condition, the facility would have an affirmative defense to an enforcement action if the requirements of 40 CFR 122.41(n) are met. If an exceedance is caused by a design or operational deficiency, then EPA has determined that the facility's performance does not represent the appropriate level of control. For these proposed limitations, 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. Additionally, some facilities may need to upgrade or replace existing treatment systems to ensure that the treatment system is designed to achieve performance to target the effluent concentrations at the option long-term average. This is consistent with EPA's costing approach for the ELG technology options and its engineering judgment developed over years of evaluating wastewater treatment processes for power plants and other industrial sectors. EPA recognizes that, as a result of the proposed rule, some dischargers, including those that are operating technologies representing the ''best available'' technology, may need to improve their treatment systems, process controls, and/or treatment system operations in order to consistently meet the effluent limitations. EPA believes that this is consistent with the Clean Water Act, which requires that discharge limitations reflect the best available technology economically achievable or the best available demonstrated control technology.

XI. Economic Impact and Social Cost Analysis

A. Introduction

EPA assessed the social costs and the projected economic impacts of the eight regulatory options described in this proposal (see Section VIII for a description of the options). This section provides an overview of the methodology EPA used to assess the social costs (or costs from the viewpoint of society rather than the regulated entity) and the economic impacts of the proposed ELGs and summarizes the results of these analyses. The Regulatory

Impact Analysis for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA)—EPA 821–R–13–005 and Benefits and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA)—EPA 821–R–13–004 reports available in the record for the rulemaking provide more details on these analyses, including discussion of uncertainties and limitations.

EPA estimated the costs to electric power producers—which include steam electric plants owned by investor-owned utilities, municipalities, states, federal authorities, cooperatives, and nonutilities, whose primary business is electric power generation or related electric power services—of complying with the proposed ELGs. As described in Section VI of this preamble, EPA estimated that 1,079 power plants operated at least one steam electric generating unit subject to the ELGs in 2009. EPA evaluated the costs and associated impacts of this proposal on these existing plants, and on new units that may be subject to the proposed revisions to the ELGs in the future. Plants that EPA estimates would incur compliance costs as a result of the proposed revisions to the ELGs are a subset of the 1,079 steam electric power plants.[64]

B. Annualized Compliance Costs

EPA's analyses of costs and economic impacts use the plant-level costs described in Section IX of this preamble. As described in that section, EPA developed plant-specific compliance costs for plants that generate a wastestream for which EPA evaluated new limitations and standards. Plant-specific compliance costs were developed for those plants for which EPA obtained detailed technical data through the industry survey. These costs consist of two principal components: initial planning and capital costs; and recurring operating and maintenance costs, which occur annually or according to a specified frequency (e.g., every 3 years, 5 years, 6 years, or 10 years). EPA applied survey weights to obtain costs for all 1,079 steam electric plants. Since all plants incurring non-zero costs have a sample weight of 1, the sum of costs for the surveyed plants also represents the total costs for the entire universe of 1,079 plants.

EPA restated compliance costs, accounting for the specific years in which each plant is assumed to undertake compliance-related activities and in 2010 dollars, using Construction Cost Index (CCI) from McGraw Hill Construction, the Employment Cost Index (ECI) published by the Bureau of Labor Statistics, and the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA). EPA used 2010 dollars based on data available at the time the analysis was developed. As a result, all dollar values reported in this analysis are in constant 2010 dollars.

EPA annualized the stream of future costs using 7 percent. The rate of 7 percent is used in the cost impact analysis as an estimate of the opportunity cost of capital.

EPA annualized one-time costs and costs recurring on other than an annual basis over a specific useful life, implementation, and/or event recurrence period, using a rate of 7 percent. For capital costs and initial one-time costs, EPA used 20 years. For O&M costs incurred at intervals greater than one year, EPA used the interval as the annualization period (i.e., 3 years, 5 years, 6 years, 10 years). EPA added annualized capital, initial one-time costs, and the non-annual portion of O&M costs to annual O&M costs to derive total annualized compliance costs, where all costs are expressed on an equivalent constantly recurring annual cost basis.

EPA uses pre- and/or after-tax compliance costs in different analyses, depending on the concept appropriate to each analysis (e.g., cost-to-revenue screening-level analyses discussed in Section XI.D are conducted using after-tax compliance costs, whereas social costs discussed in Section XI.C are calculated using pre-tax costs). For the assessment of compliance costs, EPA considered costs on both a pre-tax and after-tax basis. Pre-tax costs provide insight on the total expenditure as incurred. After-tax costs are a more meaningful measure of compliance impact on privately owned for-profit plants, and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. EPA calculated the after-tax value of compliance costs by applying combined federal and State tax rates to the pre-tax cost values for privately owned for-profit plants. For this adjustment, EPA used State corporate rates from the Federation of Tax Administrators (*http://www.taxadmin.org/*) combined with federal corporate tax rate schedules from the Department of the Treasury, Internal Revenue Service.

Table XI–1 presents the total annualized compliance costs of the regulatory options on existing plants, estimated on a pre-tax and after-tax base. The table lists the eight options in order of increasing total annualized compliance costs. As shown in the table, after-tax annualized compliance costs range between $108.4 million and $1.55 billion for Options 3a and 5, respectively, with the preferred BAT and PSES options estimated to have annualized industry-wide after-tax costs of $108.4 million, $182.2 million, $389.0 million, $635.7 million (after-tax), respectively for Options3a, 3b, 3, and 4a. The costs shown in Table XI–1 do not reflect the compliance costs for new sources.

TABLE XI–1—TOTAL ANNUALIZED COMPLIANCE COSTS
[In millions, 2010$]

7% Discount rate	Pre-tax	After-tax
Option 3a	$168.1	$108.4
Option 3b	264.6	182.2
Option 1	265.9	190.6
Option 2	393.3	280.6
Option 3	561.3	389.0
Option 4a	947.8	635.7
Option 4	1,373.2	916.9
Option 5	2,277.3	1,547.9

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 changes would reduce total annualized compliance costs. 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).

[64] As discussed in Section VIII, EPA is proposing different effluent limits for existing oil-fired generating units and units with a capacity of 50 MW or less. Because this proposed rule would set BAT equal to BPT limits, EPA accordingly did not estimate incremental costs for these units as a result of this proposed rule. Many plants are comprised of multiple units, and as such, there may be costs associated with some but not all units at a plant. The plants may incur costs for other, larger units, however, if any such units are also present; EPA's analysis includes costs for these larger units.

C. Social Costs

Social costs are the costs of the rule from the viewpoint of society as a whole, rather than regulated facilities. In calculating social costs, EPA tabulated the pre-tax costs in the year when they are incurred. EPA assumed that all plants subject to the proposed regulation that would need to upgrade their systems would install control technologies over a five-year period beginning in 2017. This accounts for the time plants would have to implement control technologies, as described in Section XVI. For the purpose of the economic analyses, EPA assumed that plants would implement control technologies 3 years after the renewal of their individual NPDES permit, following the promulgation year, with NPDES permits assumed to be renewed on time, following a 5-year cycle.[65]

EPA performed the social cost analysis over a 24-year analysis period, which combines the length of the period during which plants are expected to install the control technologies (five-year period beginning in 2017) and the useful life of the longest-lived compliance technology installed at any facility (20 years). Under this framework, the last year for which costs (and benefits) were tallied in the analysis is 2040. EPA calculated social cost of the eight regulatory options for existing steam electric power plants using a 3 percent discount rate. EPA also calculated social costs using an alternative discount rate of 7 percent.[66] For the analysis of social costs, EPA discounted all costs to the beginning of 2014, which is the expected promulgation year for the proposed rule.

As described in Section XVII.B, EPA does not believe the proposed rule would lead to additional costs to permitting authorities. Consequently, the only category of costs necessary to calculate social costs are compliance costs; social costs differ from pre-tax compliance costs due to timing of costs and discounting using a societal discount rate.

Table XI–2 presents the total annualized social cost of the regulatory options on existing plants, calculated using 3 percent and 7 percent discount rates. The table lists the eight options in order of increasing total social costs calculated using a 3 percent discount rate.

TABLE XI–2—TOTAL ANNUALIZED SOCIAL COSTS
[In millions, 2010$]

Regulatory option	3% Discount rate	7% Discount rate
Option 3a	$185.2	$164.5
Option 1	268.3	259.2
Option 3b	281.4	257.2
Option 2	386.8	380.8
Option 3	572.0	545.3
Option 4a	954.1	914.7
Option 4	1,381.2	1,323.2
Option 5	2,328.8	2,209.4

At 3 percent discount rate, total annualized social costs for existing plants vary from $185.2 million under Option 3a to $2.3 billion under Option 5, with the preferred BAT and PSES options having total annualized social costs of $185.2 million, $281.4 million, $572.0 million, and $954.1 million, respectively for Options 3a, 3b, 3 and 4a. The values presented in Table XI–2 for the 7 percent discount rate are slightly lower than the comparable values (pre-tax) presented in Table XI–1 due to the timing of compliance expenditures (e.g., $545.3 million versus $561.3 million, for Option 3).

These social costs do not reflect anticipated unit retirements and conversions anticipated through 2024. As noted in the previous Section, EPA anticipates that these changes would reduce total compliance costs incurred by the Steam Electric power industry, and therefore reduce the social costs of this action.

D. Economic Impacts

EPA assessed the economic impacts of the regulatory options in two ways: (1) A screening-level assessment of the impact of compliance costs on existing plants and the entities that own those plants, based on comparison of compliance costs to plant and entity revenue; and (2) an assessment of the impact of the proposed regulatory options for both existing and new plants within the context of the broader electricity market, which includes an assessment of incremental plant closures attributable to the proposed ELGs. EPA used the results of the screening-level assessment to inform the selection of regulatory options to be analyzed using the second approach.

The following sections summarize the methods and findings for these analyses.

1. Screening-Level Assessment of Impacts on Existing Plants and Parent Entities Incurring Compliance Costs Associated With This Proposed Rule

EPA conducted a screening-level analysis of the rule's potential impact to existing steam electric plants and parent entities based on cost-to-revenue ratios. For each of the two levels of analysis (plant and parent entity), the Agency assumed, for analytic convenience and as a worst-case scenario, that none of the compliance costs would be passed onto consumers through electricity rate increases and would instead be absorbed by complying plants and their parent entities. In performing these and other impact analyses, EPA used the survey weights to extrapolate impacts assessed initially for a sample of plants to all 1,079 steam electric plants and to their respective owning parent entities.

a. Cost-to-Revenue Analysis for Plants Incurring Compliance Costs Associated with this Proposed Rule

EPA calculated the annualized after-tax compliance costs of the regulatory options as a percent of baseline annual revenues.[67] Revenue estimates used in this analysis were developed using Energy Information Administration (EIA) data. (See Chapter 4 of the RIA report for a more detailed discussion of the methodology used for the plant-level cost-to-revenue analysis).[68]

Table XI–3 summarizes the screening-level plant-level cost-to-revenue analysis results for the eight main regulatory options. EPA estimates that the vast majority of plants subject to the proposed ELGs will incur annualized costs amounting to less than 1 percent of revenue for all eight regulatory options (887 to 1,051 plants, or 82 to 97 percent of the total 1,079 steam electric plants). A significant share of these plants incur no compliance costs. For the preferred BAT and PSES options (Options 3a, 3b, 3 and 4a), 92 percent to 97 percent of steam electric plants have estimated costs that are less than 1 percent of revenue. The number of plants with ratios between 1 percent and 3 percent, and above 3 percent,

[65] These assumed technology installation years do not necessarily correspond to the actual years in which individual facilities would be required to meet the effluent limits or standards as specified in their permit, but is a reasonable distribution of installation years for the aggregate set of steam electric plants incurring compliance costs. These assumptions reflect the approximate years in which technology installation would reasonably be expected to occur, assuming that expiring permits are renewed exactly on the 5-year mark. Note that EPA also analyzed the effects of other technology installation periods. The results of these analyses are detailed in Appendix B of the RIA report.

[66] These discount rate values follow guidance from the Office of Management and Budget (OMB) regulatory analysis guidance document, Circular A–4 (OMB, 2003).

[67] For private, tax-paying entities, *after-tax costs* are a more relevant measure of potential cost burden than *pre-tax costs.* For non tax-paying entities (e.g., State government and municipality owners of affected plants), the estimated costs used in this calculation include no adjustment for taxes.

[68] To develop the average of year-by-year revenue values over the data years, EPA set aside from the averaging calculation, revenue values for years that are substantially lower than the otherwise ''steady state average''—e.g., because of a generating unit being out of service for an extended period.

generally rises when moving from Option 3a to Option 5. For the preferred BAT and PSES options (Options 3a, 3b, 3 and 4a), two to six percent of plants have cost-to-revenue ratios between 1 and 3 percent and less than one percent to two percent have ratios above 3 percent.

TABLE XI–3—PLANT-LEVEL COST-TO-REVENUE ANALYSIS RESULTS BY REGULATORY OPTION [a]

Option	No data on revenue [b]	Number of plants with cost-to-revenue ratio of			
		0%	0–1%	1–3%	>3%
Option 3a	5	1,008	43	22	1
Option 3b	5	994	54	24	2
Option 1	5	959	93	17	5
Option 2	5	959	86	18	11
Option 3	5	920	102	38	14
Option 4a	5	875	114	65	20
Option 4	5	798	111	117	48
Option 5	5	798	89	115	72

[a] This analysis makes a counterfactual, conservative assumption of zero cost pass-through. Plant counts are weighted estimates.
[b] EIA does not report necessary data to estimate revenue for 5 plants.

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

EPA also assessed the economic impact of the eight regulatory options at the parent entity-level. The screening-level cost-to-revenue analysis at the parent entity level provides insight on the impact of compliance requirements on those entities that own more than one plant incurring compliance costs associated with this proposed rule. For this analysis, EPA identified the domestic parent entity of each plant and obtained the entity's revenue from the industry survey or from publicly available data sources. In this analysis, the domestic parent entity associated with any given plant is defined as that entity that has the largest ownership share in the plant.

For each parent entity, EPA compared the total annualized after-tax compliance costs, as of 2014, and the identified parent entity's total revenue (see Chapter 4 of the RIA report for details). The total parent-level annualized after-tax compliance costs represent total costs for all steam electric plants in which the entity is the majority owner.

Compliance costs for the regulatory options were developed based on surveyed plants (see Section XI.D.1.a). For the parent entity-level analysis, EPA considered two approximate bounding cases to analyze the owners of all 1,079 steam electric plants, based on the survey weights developed from the industry survey. These cases, which are described in more detail in Chapter 4 of the RIA, provide a range of estimates for the number of entities incurring compliance costs and the costs incurred by any entity owning a steam electric plant.

Table XI–4 summarizes the results of the entity-level analysis for the two analytic cases and the eight regulatory options.

TABLE XI–4—PARENT ENTITY-LEVEL AFTER-TAX ANNUAL COMPLIANCE COSTS AS A PERCENTAGE OF REVENUE [a]

Option	Total number of entities	Not analyzed due to lack of revenue information		Number and percentage with after tax annual compliance costs/annual revenue of:							
				0%		0–1%		1–3%		3% or Greater	
		#	%	#	%	#	%	#	%	#	%
Case 1: Lower-bound estimate of number of entities owning steam electric plants; upper bound estimate of total compliance costs that an entity may incur											
Option 3a	243	14	6	205	84	22	9	2	1	0	0
Option 3b	243	14	6	201	83	26	11	2	1	0	0
Option 1	243	14	6	173	71	51	21	1	<1	4	2
Option 2	243	14	6	173	71	46	19	6	2	4	2
Option 3	243	14	6	168	69	49	20	7	3	5	2
Option 4a	243	14	6	157	65	55	23	11	5	6	2
Option 4	243	14	6	137	56	64	26	21	9	7	3
Option 5	243	14	6	137	56	57	23	20	8	15	6
Case 2: Upper-bound estimate of number of entities owning steam electric plants; lower bound estimate of total compliance costs that an entity may incur											
Option 3a	507	30	6	453	89	22	4	2	<1	0	0
Option 3b	507	30	6	449	89	26	5	2	<1	0	0
Option 1	507	30	6	421	83	51	10	1	<1	4	1
Option 2	507	30	6	421	83	46	9	6	1	4	1
Option 3	507	30	6	416	82	49	10	7	1	5	1
Option 4a	507	30	6	405	80	55	11	11	2	6	1
Option 4	507	30	6	385	76	64	13	21	4	7	1
Option 5	507	30	6	385	76	57	11	20	4	15	3

equals the number of entities.

[a] This analysis makes a counterfactual, conservative assumption of zero cost pass-through.

The cost-to-revenue ratios provide screening-level indicators of potential economic impacts. Entities incurring costs below 1 percent of revenue are unlikely to face economic impacts, while entities with costs between 1 percent and 3 percent of revenue have a higher chance of facing economic impacts, and entities incurring costs above 3 percent of revenue have a still higher probability of economic impacts. As presented in Table XI–4, EPA estimated that the number of entities owning steam electric plants ranges from 243 (lower bound estimate) to 507 (upper bound estimate), depending on the assumed ownership structure of plants not surveyed. Under the lower-bound case, EPA estimates that the vast majority of parent entities will incur annualized costs of less than 1 percent of revenues under all eight analyzed regulatory Options (the shares are 93, 93, 89, and 87 percent under Options 3a, 3 and 4a, respectively). These observations also hold true under the upper bound case; an estimated 94, 94, 92, and 91 percent of parent entities incur annualized costs of less than 1 percent of revenue, for Options 3a, 3b, 3 and 4a, respectively.

Overall, this screening-level analysis shows that the entity-level compliance costs are low in comparison to the entity-level revenues; very few entities are likely to face economic impacts at any level for any of the four preferred BAT and PSES options (Options 3a, 3b, 3 and 4a).

2. Assessment of the Impacts in the Context of Electricity Markets

In analyzing the impacts of regulatory actions affecting the electric power sector, EPA has used the Integrated Planning Model (IPM), a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. The model is designed to evaluate the effects of changes in production costs at the level of the individual generating unit, on the total cost of electricity supply, subject to specified demand and emissions constraints. To assess facility and market-level effects of these proposed ELGs, EPA used an updated version of this same analytic system: Integrated Planning Model Version 4.10 MATS (IPM V4.10).

Use of a comprehensive, market analysis system is important in assessing the potential impact of the regulatory options because of the interdependence of electricity generating units in supplying power to the electric transmission grid. Increases in electricity production costs at some plants can have a range of broader market impacts affecting other plants, including the likelihood that various plants are dispatched, on average.

IPM V4.10 provides outputs for the North American Electric Reliability Corporation (NERC) regions that lie within the continental United States. IPM V4.10 does not analyze electric power operations in Alaska and Hawaii because these states' electric power operations are not connected to the continental U.S. power grid. However, none of the steam electric plants that are estimated to incur compliance costs associated with this proposal are located in these two regions.

IPM V4.10 is based on an inventory of U.S. utility- and non-utility-owned boilers and generators that provide power to the integrated electric transmission grid, as recorded in EIA 860 (2006) and EIA 767 (2005) databases.[69] The IPM baseline universe of plants includes nearly all of the steam electric plants that could be subject to the proposed ELGs and are estimated to incur compliance costs.[70] IPM Version 4.10 embeds a baseline energy demand forecast that is derived from DOE's *Annual Energy Outlook 2010* (AEO2010). IPM V4.10 also incorporates in its analytic baseline the expected compliance response to existing regulatory requirements for the following promulgated air regulations affecting the power sector: the final Mercury and Air Toxics Standards (MATS) rule; the final Cross-State Air Pollution Rule (CSAPR)[71]; regulatory SO_2 emission rates arising from State Implementation Plans (SIP); Title IV of the Clean Air Act Amendments; NO_X SIP Call trading program; Clean Air Act Reasonable Available Control Technology requirements and Title IV unit specific rate limits for NO_X; the Regional Greenhouse Gas Initiative; Renewable Portfolio Standards; New Source Review Settlements; and several state-level regulations affecting emissions of SO_2, NO_X, and mercury that are already in place or expected to come into force by 2017.

In contrast to the screening-level analyses, which are static analyses and do not account for interdependence of electric generating units in supplying power to the electric transmission grid, IPM accounts for potential changes in the generation profile of steam electric and other units and consequent changes in market-level generation costs, as the electric power market responds to higher generation costs for steam electric units due to the proposed ELGs. IPM is also dynamic in that it is capable of using forecasts of future conditions to make decisions for the present. Additionally, in contrast to the screening-level analyses in which EPA assumed no pass through of compliance costs, IPM depicts production activity in wholesale electricity markets where some recovery of compliance costs through increased electricity prices is possible but not guaranteed.

In performing analyses based on IPM V4.10, EPA used as its baseline—i.e., reflecting the world without this proposed regulation—a projection of electricity markets and facility operations over the period from the expected promulgation year, 2014, through 2030. As discussed above, this baseline accounts for compliance with the recently promulgated federal air rules.

As discussed in greater detail in Appendix C of the RIA, IPM generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. In analyzing the proposed ELGs, EPA specified additional fixed and variable costs that are expected to be incurred by specific steam electric plants and generating units to comply with the proposed ELGs. EPA then ran IPM including these additional costs to determine the dispatch of electricity generating units that would meet projected demand at

[69] In some instances, plant information has been updated to reflect known material changes in a plant's generating capacity since 2006.

[70] The IPM plant universe excludes two steam electric plants estimated to incur compliance costs under the proposed ELG scenarios EPA analyzed in IPM. See Chapter 5 of the RIA report for more details.

[71] EPA's Cross-State Air Pollution Rule (CSAPR) was promulgated to replace EPA's Clean Air Interstate Rule (CAIR), which had been remanded to EPA in 2008. However, on December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit stayed CSAPR pending judicial review and left CAIR in place. On August 21, 2012 the Court issued an opinion vacating CSAPR and again leaving CAIR in place pending development of a valid replacement. On March 29, 2013, the United States filed a petition asking the Supreme Court to review the D.C. Circuit's opinion. Nevertheless, as explained above, CAIR remains in effect at this time. In light of the continuing uncertainty on CAIR and CSAPR, EPA does not believe it would be appropriate or possible at this time to adjust emission projections on the basis of speculative alternative emission reduction requirements in 2020. EPA expects that the decision vacating CSAPR and leaving CAIR in place has a minimal effect on the results of the analysis conducted in support of the proposed ELGs.

the lowest costs, subject to the same constraints as those present in the analysis baseline. The least-cost dispatch solution for meeting electricity supply may change as the result of the changes in fixed and variable costs at the level of the individual plant and generating unit, which EPA estimates would occur as a result of the proposed ELGs. These estimated changes in plant- and unit-specific production levels and costs—and, in turn, changes in total electric power sector costs and production profile—are key data elements in evaluating the expected national and regional effects of the proposed ELGs.

EPA used the screening-level analyses described above to inform the selection of regulatory options to be analyzed using IPM. In allocating resources to analytical effort, EPA chose to run IPM in a phased approach, starting with Option 3 and then Option 4, with the notion to proceed if additional model runs were warranted.

EPA first analyzed a scenario developed based on Option 3 but where the total compliance costs and the set of existing plants that are assigned costs varied slightly from those in the Option 3 discussed in other parts of this preamble.[72] Thus, the Option 3 scenario analyzed using IPM and discussed below did not include small changes to the timing of some O&M costs and to the set of plants assigned compliance costs for this option. Because of these changes and the need to protect data claimed as CBI by plant owners, total compliance costs for Option 3 as analyzed in IPM are approximately 10 percent lower than for the proposed Option 3 discussed in the rest of this document. EPA also analyzed a scenario in IPM that corresponds to BAT and PSES Option 4 discussed elsewhere in this notice.[73] Both scenarios analyzed in IPM included NSPS and PSNS compliance costs for new coal generation, based on the preferred Option 4 for new sources.

The two scenarios analyzed in IPM provide insight on the market impacts of the regulatory options EPA considered for this proposal. Options 3 and 4 as analyzed in IPM are similar enough to these proposed Options 3 and 4 to provide valuable insight on the likely impacts of the proposed ELGs. Options 3a, 1, 2, and 3b are less stringent than either of the two other options analyzed in IPM; as discussed further below, the relatively small impacts observed when analyzing the Option 3 scenario suggest that the impacts of Options 3a, 1, 2 and 3b would be less than Option 3. EPA did not analyze Option 4a due to time and resource constraints, but expects that this option could have impacts between those of Options 3 and 4. EPA did not analyze Option 5 based on screening-level analysis results, which showed that compliance costs could result in financial stress to some entities owning steam electric plants. As shown in Section XI.D.1, under Option 5, about three times as many entities owning steam electric plants would incur costs that exceed 3 percent of revenue than under Options 3 (15 versus 5 entities). Twice as many entities owning steam electric power plants are estimated to incur costs that exceed 3 percent of revenue under Option 5, when compared to Option 4 (15 versus 7 entities). As discussed in Section XVII.C, the potential cost impacts to small entities are also greater under Option 5 than under Options 3 and 4.

The IPM V4.10 runs provide analysis results for selected run-years: 2020 and 2030. These analysis years, each of which represents multiple years, take into account the expected promulgation year for these proposed ELGs (2014) and the years in which all plants would be expected to install compliance technology (five-year period beginning in 2017). In the following sections, EPA reports results for the run-year 2030, which represents years 2025–2034, by which time all plants subject to this rulemaking will meet the revised guidelines and standards and all compliance costs will be reflected in production costs (i.e., steady state of post-compliance operations). EPA considered impact metrics of interest at three levels of aggregation: (1) Impact on national and regional electricity markets (i.e., all electric power generation, including steam and non-steam plants), (2) impact on steam electric power generating plants as a group (i.e., the 1,079 plants subject to the proposed ELGs, not all of which are projected to incur compliance costs), and (3) impact on individual steam electric plants incurring compliance costs.

All results presented below are representative of modeled market conditions in the years 2025–2034. While costs are in 2010 dollars, they are reflective of costs in the modeled years and are not discounted to the start of EPA's analysis period of 2014.[74]

a. Impact on National and Regional Electricity Markets

For the assessment of market level electricity impacts, EPA considered five output metrics from IPM V4.10: (1) Incremental early retirements and capacity closures, calculated as the difference between capacity under the regulatory options and capacity under the baseline, which includes both full plant closures and partial plant closures (i.e., unit closures) in aggregate capacity terms; (2) incremental capacity closures as a percentage of baseline capacity; (3) post-compliance changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; (4) changes in annual costs (fuel, variable O&M, fixed O&M, and capital); and (5) post-compliance changes in energy price, where electricity prices are defined as the wholesale prices received by plants for the sale of electricity they generate.

Table XI–5 presents results for the two market model analysis scenarios. The table provides the baseline capacity and the values of each of the five metrics above, with national totals and detail at level of regional electricity markets defined on the basis of the eight NERC regions defined in IPM.

Additional results are presented in Chapter 5 of the RIA report. Chapter 5 also presents a more detailed interpretation of the results of the market-level analysis.

[72] The costs as analyzed in IPM differ slightly from those used in the non-IPM analyses. For more details on these differences, see Chapter 5 of the RIA report. Note that the scenario assigns compliance costs for existing plants based on Option 3, and compliance costs for new capacity projected in IPM based on Option 4.

[73] Compliance costs differ only slightly (1 percent lower) from costs used in other analyses, primarily to avoid disclosing CBI. There are no differences in the set of plants estimated to incur compliance costs or in the timing of the costs. For more details, see Chapter 5 of the RIA report.

[74] In contrast, the social cost estimated in Section XI.C reflects the discounted value of compliance costs over the entire 24-year period of analysis, as of 2014. Additionally, screening-level analyses presented in earlier sections are static analyses and do not account for interdependence of electric generating units in supplying power to the electric transmission grid. In contrast, IPM accounts for potential changes in generation profile of steam electric and other units and consequent changes in market-level generation costs, as the electric power market responds to higher generation costs for steam electric units due to the proposed ELG.

TABLE XI–5—IMPACT OF MARKET MODEL ANALYSIS OPTIONS ON NATIONAL AND REGIONAL MARKETS AT THE YEAR 2030

NERC region	Baseline capacity (GW)	Incremental early retirements/closures [a]		Change in variable production cost (2010$/MWh or % of baseline)		Change in annual costs (million 2010$ or % of baseline)		Change in electricity price (2010$/MWh or % of baseline)	
		Capacity (GW)	% of Baseline closures						
Option 3:									
ERCOT	98	0	0.0	$0.11	0.3%	$72	0.4%	$0.21	0.3%
FRCC	68	0	0.0	0.14	0.3	49	0.3	0.23	0.3
MRO	76	0	0.0	0.02	0.1	53	0.4	0.03	0.1
NPCC	73	0	0.0	0.06	0.2	15	0.1	0.19	0.3
RFC	237	0	0.0	0.12	0.5	276	0.5	0.19	0.3
SERC	274	0	0.0	0.17	0.6	322	0.6	0.24	0.4
SPP	59	0	−0.7	0.08	0.3	35	0.3	0.17	0.3
WECC	220	0	0.0	0.05	0.2	50	0.1	0.15	0.2
Total	1,106	0	0.0	0.11	0.4	872	0.4		N/A
Option 4:									
ERCOT	98	0	0.0	0.14	0.4	85	0.5	0.07	0.1
FRCC	68	0	0.0	0.15	0.1	33	0.2	0.09	0.1
MRO	74	0	0.0	0.11	0.5	134	1.0	−0.05	−0.1
NPCC	73	0	0.6	0.03	0.1	32	0.2	0.04	0.1
RFC	237	1	0.3	0.29	1.1	804	1.5	0.15	0.2
SERC	274	0	0.0	0.28	1.0	662	1.2	0.19	0.3
SPP	60	0	−0.6	0.15	0.5	72	0.7	0.09	0.2
WECC	220	0	0.0	0.03	0.1	52	0.1	0.04	0.1
Total	1,106	0	0.0	0.18	0.6	1,874	0.9		N/A

[a] Values for incremental early retirements or closures represent change relative to the baseline run. IPM may show partial (i.e., unit) or full plant early retirements (closures) for a given option. It may also show avoided closures (negative closure values) in which a unit or plant that is projected to close in the baseline, is estimated to continue operating in the post-compliance case. Avoided closures may occur among plants that incur no compliance costs or for which compliance costs are low relative to other steam electric plants.[75]

As shown in Table XI–5, the Market Model Analysis indicates that Option 3 would have very small effects in overall electricity markets, on both a national and regional sub-market basis, in the year 2030. Overall at the national level, the net change in total capacity, including reductions in capacity (which includes early retirements) and capacity additions in new plants/units, results in approximately 1GW of additional capacity (less than 0.05 percent total market capacity), which is too small to appear in Table XI–5. This increase in capacity is expected to take place entirely in the SPP NERC region (0.8 percent of total SPP capacity) and is the result of reduction in retired capacity (avoided capacity closures) and increase in new capacity and capacity at existing generating units.[76] Consequently, Option 3 is expected to have negligible effect on capacity availability and supply reliability at the national level. Overall impacts on electricity prices are similarly minimal. While electricity prices are expected to increase in all NERC regions, the magnitude of this increase varies across regions and ranges from $0.03 per MWh (0.1 percent) in MRO to $0.24 per MWh (0.4 percent) in SERC. Finally, at the national level, total costs increase by approximately 0.4 percent of the baseline value—again, a modest amount. Across regions, no NERC region records an increase in power sector total costs exceeding 1 percent.

The findings for Option 4 *overall* lie very close to those of Option 3. Similar to Option 3, the net change in total capacity under Option 4 is essentially zero, indicating that this option would be expected to have a negligible effect on capacity availability and supply reliability, at the national level. This is also the case at the regional level, with small capacity changes in RFC (early retirement) and SPP (avoided retirement). Option 4 also has a slight impact on electricity prices across all NERC regions, with increases of no more than 0.3 percent and a 0.1 percent reduction in the MRO region. At the national level, variable production costs—fuel and variable O&M—increase by $0.18 per MWh or 0.6 percent. While variable costs increase in all NERC regions, the change varies by region ranging from $0.03 per MWh in NPCC and WECC to $0.29 in RFC. As expected for Option 4, which is more expensive than Option 3, the increase in total annual costs for the electric power sector is greater than under Option 3. At the national level, total annual costs increase by $1.9 billion (0.9 percent). As discussed in greater detail in Chapter 5 of the RIA document, the largest shares of this increase occur in variable O&M; capital costs increase by a much smaller amount. As discussed above, EPA expects the impacts of Options 3a and 3b to be smaller than those of Option 3, and the impacts of Option 4a to be between those of Options 3 and 4.

b. Impact on Existing Steam Electric Plants

EPA used IPM V4.10 results for 2030 to assess the potential impact of the regulatory options on steam electric plants. In contrast to the previously described electricity market-level

[75] 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- or plant-specific compliance actions. ERCOT (Electric Reliability Council of Texas), FRCC (Florida Reliability Coordinating Council), MRO (Midwest Reliability Organization), NPCC (Northeast Power Coordination Council), RFC (ReliabilityFirst Corporation), SERC (Southeastern Electricity Reliability Council), SPP (Southwest Power Pool), and WECC (Western Electricity Coordinating Council).

[76] Avoided capacity closures occur when one or more generating units that are otherwise projected to cease operations in the baseline become more economically attractive sources of electricity in the post-compliance case, because of relative changes in the economics of electricity production across the full market, and thus avoid closure.

analysis, which sought to assess the impact of the proposed ELGs regulatory options on the entire electric power sector, the purpose of this second analysis is to assess impacts on steam electric plants specifically.

Table XI–6 reports results for steam electric plants, as a group. In this case, EPA looked at the following metrics IPM produces: (1) Incremental early retirements and capacity closures, calculated as the difference between capacity under the regulatory options and capacity under the baseline, which includes both full plant closures and partial plant closures (i.e., unit closures) in aggregate capacity terms; (2) incremental capacity closures as a percentage of baseline capacity; (3) post-compliance change in electricity generation; (4) post-compliance changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; and (5) changes in annual costs (fuel, variable O&M, fixed O&M, and capital. Items (1) and (2) are instrumental in determining the economic achievability of various regulatory options.

TABLE XI–6—IMPACT OF MARKET MODEL ANALYSIS OPTIONS ON STEAM ELECTRIC PLANTS AS A GROUP AT THE YEAR 2030

NERC region	Baseline capacity (MW)	Incremental early retirements/ closures [a]		Change in total generation (GWh or % of baseline)		Change in variable production cost (2010$/ MWh or % of baseline)		Change in annual costs (million 2010$ or % of baseline)	
		Capacity (MW)	% of Baseline capacity						
Option 3:									
ERCOT	32,275	0	0.0	−83	0.0%	$0.09	0.3%	$35	0.5%
FRCC	32,227	0	0.0	−25	0.0	0.11	0.3	27	0.4
MRO	34,899	0	0.0	83	0.0	−0.02	−0.1	26	0.3
NPCC	16,629	0	0.0	−3	0.0	0.07	0.2	9	0.2
RFC	122,205	0	0.0	234	0.0	0.15	0.5	225	0.7
SERC	131,895	0	0.0	−1,140	−0.2	0.24	0.8	283	0.8
SPP	31,269	−102	−0.3	−123	−0.1	0.04	0.1	15	0.2
WECC	54,494	0	0.0	103	0.0	0.05	0.2	22	0.2
Total	455,894	−102	0.0	−954	0.0	0.13	0.5	642	0.6
Option 4:									
ERCOT	32,275	0	0.0	−227	−0.1	0.16	0.5	66	1.0
FRCC	32,227	0	0.0	78	0.1	0.05	0.1	27	0.4
MRO	34,899	0	0.0	212	0.1	0.12	0.5	108	1.4
NPCC	16,629	−431	−2.6	−4	0.0	0.10	0.3	29	0.7
RFC	122,205	681	0.6	−2,351	−0.3	0.38	1.3	561	1.8
SERC	131,895	0	0.1	−2,178	−0.3	0.43	1.5	607	1.8
SPP	31,269	−30	−0.1	−510	−0.3	0.16	0.6	59	0.9
WECC	54,494	0	0.0	63	0.0	0.07	0.3	46	0.4
Total	455,894	317	0.1	−4,916	−0.2	0.28	1.0	1,504	1.4

[a] Values for incremental early retirements or closures represent change relative to the baseline run. IPM may show partial (i.e., unit) or full plant early retirements (closures) for a given option. It may also show avoided closures (negative closure values) in which a unit or plant that is projected to close in the baseline, is estimated to continue operating in the post-compliance case. Avoided closures may occur among plants that incur no compliance costs or for which compliance costs are low relative to other steam electric plants.[77]

Under Option 3, the net change in total capacity for steam electric plants is very small; this is similar to prior findings when considering the electricity market as a whole. For the group of steam electric plants, total capacity increases by 106 MW (not shown in Table XI–6, see RIA for details) or approximately 0.02 percent of the 455,894 MW baseline capacity. This results in part from *avoided* capacity closures of 102 MW in the SPP region. Option 3 results in no closures, full (plant) or partial (unit), in the other seven regions.

The change in total generation is an indicator of how steam electric plants fare, relative to the rest of the electricity market. While at the market level there is essentially no projected change in total electricity generation,[78] for steam electric plants, total available capacity and electricity generation at the national level is projected to fall by less than 0.1 percent. At the regional level, five NERC regions—ERCOT, NPCC, RFC, SERC, and SPP—are projected to experience a reduction in electricity generation from steam electric plants, ranging from 3 GWh in NPCC (less than 0.01 percent) to 1,140 GWh in RFC (0.2 percent). The other three NERC regions are each projected to experience a very modest increase in electricity generation from steam electric plants of less than 0.1 percent.

Finally, at the national level, variable production costs at steam electric plants increase by approximately 0.5 percent. These effects vary by region from about −0.1 percent in MRO to 0.8 percent in SERC. These findings of very small national and regional effects in these impact metrics confirm EPA's assessment that Option 3 can be expected to have little economic consequence in national and regional electricity markets.

Results of the analysis for Option 4 show almost no change in either total generating capacity or electricity generation for the electric power sector as whole, and steam electric generating capacity and electricity generation fall slightly by 306 MW (0.07 percent) (not shown in Table XI–6, see RIA for

[77] 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- or plant-specific compliance actions.

[78] At the national level, the demand for electricity does not change between the baseline and the analyzed regulatory options (generation within the regions is allowed to vary) because meeting demand is an exogenous constraint imposed by the model.

details) and 4,916 GWh (0.2 percent), respectively. The steam electric capacity reduction includes early retirement and avoided retirement of generating units with the net effect of the two types of changes being capacity losses. Thus, under the analysis for Option 4, 14 generating units close (1,125 MW) and 5 generating units avoid closure (808 MW), leading to an estimated net closure of nine generating units (317 MW, see Table XI–6). All 14 units that are projected to close in this scenario are located within six plants that are projected to continue operating. In other words, Option 4 is not projected to result in any full plant closures.[79]

Findings for the change in total costs and variable production costs under Option 4 also exceed those under Option 3. There is a 1.4 percent increase in total costs at the national level, with SERC recording the largest increase of 1.8 percent. As detailed in Chapter 5 of the RIA document, at the national level, the increase in total costs occurs in fixed and variable O&M (3.2 percent and 9.3 percent, respectively) while fuel costs and capital costs decline (0.4 percent and 3.2 percent, respectively). At the national level, variable production costs increase by 1.0 percent, with SERC recording the highest increase of 1.5 percent. As for impacts on national and regional markets, EPA expects the impacts on steam electric plants of Options 3a and 3b to be smaller than those of Option 3, and the impacts of Option 4a to be between those of Options 3 and 4.

c. Impact on Individual Steam Electric Plants Incurring Compliance Costs Under This Rulemaking

Results for the group of steam electric plants as a whole may mask shifts in economic performance among individual plants incurring compliance costs associated with the proposed ELGs. To assess potential plant-level effects, EPA analyzed plant-specific changes between the base case and the post-compliance cases for the following metrics: (1) Capacity utilization (defined as annual generation (in MWh) divided by [capacity (MW) times 8,760 hours]) (2) electricity generation, and (3) variable production costs per MWh, defined as variable O&M cost plus fuel cost divided by net generation.

Table XI–7 presents the estimated number of plants incurring compliance costs with specific degrees of change in operations and financial performance for the two regulatory options EPA analyzed using IPM. Metrics of interest include the number of plants with reductions in capacity utilization or generation (on left side of the table), and the number of plants with increases in variable production costs (on right side of the table).

TABLE XI–7—IMPACT OF MARKET MODEL ANALYSIS OPTIONS ON INDIVIDUAL STEAM ELECTRIC PLANTS INCURRING COMPLIANCE COSTS AT THE YEAR 2030—NUMBER OF PLANTS BY IMPACT MAGNITUDE

Economic measures	Reduction			No Change	Increase			N/A[b]
	≥ 3%	≥1 and <3%	<1%		<1%	≥1 and <3%	≥ 3%	
Option 3								
Change in Capacity Utilization[a]	6	7	62	438	41	4	6	101
Change in Generation	15	3	53	443	38	4	8	101
Change in Variable Production Costs/MWh	2	3	183	72	239	28	23	115
Option 4								
Change in Capacity Utilization[a]	6	4	131	291	113	7	9	104
Change in Generation	12	4	118	302	104	6	15	104
Change in Variable Production Costs/MWh	2	2	136	46	225	99	37	118

[a] The change in capacity utilization is the difference between the capacity utilization percentages in the base case and post-compliance cases. For all other measures, the change is expressed as the percentage change between the base case and post-compliance values.

[b] Plants with status changes in either baseline or post-compliance scenario have been excluded from these calculations. For example, for a plant that is projected to close in the post-compliance case, the reduction in variable costs per MWh of generated electricity would be 100 percent. Specifically, there are 23 full baseline plant closures, 77 partial baseline plant closures, and 1 avoided plant closure under Option 3. There are 23 full baseline plant closures, 72 partial baseline plant closures, 3 avoided plant closures, and 6 partial policy plant closures under Option 4.

For Option 3, the analysis of changes in individual plants indicates that most plants experience only slight effects—no change, or less than a 1 percent reduction or 1 percent increase. Only 13 plants (2 percent) are estimated to incur a reduction in capacity utilization exceeding 1 percent and 18 plants (3 percent) incur a reduction in generation exceeding 1 percent. The estimated change in variable production costs is higher; 51 plants (8 percent) incur an *increase* in variable production costs exceeding 1 percent; for 23 of these plants, this increase exceeds 3 percent.

Results for Option 4 show greater effects as compared to Option 3. While the difference in the policy impact on capacity utilization and generation is small, the difference in policy impact on variable costs is greater. The reduction in capacity utilization and generation is estimated to exceed 1 percent for 10 and 16 plants (approximately 2 percent), respectively. The increase in variable production costs is estimated to exceed 1 percent for 136 plants, 99 of which have an increase between 1 and 3 percent.

As for the market and industry-level results discussed above, EPA expects the impacts of Options 3a and 3b to be smaller than those of Option 3, and the impacts of Option 4a to be between those of Options 3 and 4.

3. Summary of Economic Impacts for Existing Sources

EPA performed cost and economic impact assessment in two parts. The first set of cost and economic impact analyses—including entity-level impacts at both the plant and parent company levels—reflects baseline operating characteristics of plants incurring compliance costs and assumes no changes in those baseline operating characteristics (e.g., level of electricity generation and revenue) as a result of the requirements of the proposed regulatory options. They can serve as screening-level indicators of the relative cost of different regulatory options to plants, owning entities, or consumers, but are not determinative in terms of

[79] 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- or plant-specific compliance actions.

assessing the economic achievability of various regulatory options.

The second set of analyses look at broader electricity market impacts taking into account the interconnection of regional and national electricity markets, for the full industry, for steam electric plants only, and at the distribution of impacts at the plant level. This second analysis provides insight on the impacts of the proposed ELGs on steam electric plants, as well as the electricity market as a whole, including generation capacity closure, and changes in generation and wholesale electricity prices. Results of the Market Model for Option 3 show no incremental plant closures (complete or partial) and relatively small changes in production costs. This analysis shows that Option 3 for existing steam electric plants is economically achievable. This same conclusion applies to Options 3a and 3b since the costs of these options are less than those of Option 3.

The Market Model analysis of Option 4 shows slightly higher, but still relatively small, impacts on steam electric generation and individual plants as compared to Option 3. For example, the results show incremental partial capacity retirements of 317 MW at the national level (1.4 percent relative to the baseline without the proposed ELGs), no full plant retirements, and greater increases in production costs (1.0 percent), as compared to Option 3. Given these impacts, and since the impacts of Option 4a would fall between those of Options 3 and 4, EPA believes that Option 4a is also economically achievable.

4. Summary of Economic Impacts for New Sources

Electric power generating units that meet the definition of a new source would be required to meet the proposed NSPS or PSNS. EPA developed estimated compliance costs for new units using a methodology similar to that used to develop compliance costs for existing plants, with the notable exception that EPA did not develop new unit compliance costs that are plant specific, which would require EPA to predict which plants will construct new units.

EPA assessed the possible impact of incremental costs associated with this proposal for new units in two ways: (1) As part of its analysis using IPM discussed in Section XI.D.3; and (2) by comparing the incremental costs for new units to the overall cost of building and operating new scrubbed coal units.

EPA estimated the incremental capital and fixed O&M costs for each new electricity generating coal unit projected to come online in IPM. The Agency estimated variable O&M costs assuming that any new unit would operate, on average, 330 days per year. IPM takes these additional regulatory costs into account when trying to determine the least costly means of meeting the total electricity demand. Results of the IPM analysis are summarized in Section XI.D.3 of this preamble and discussed in detail in Chapter 5 of the RIA document. IPM results show no barrier to new generation capacity for 2025–2034 as a result of compliance with the preferred NSPS/PSNS regulatory options (Option 4). The model estimates no change in coal steam capacity relative to the baseline, and small increases in generation capacity from other steam (0.3 percent), combustion turbine (0.3 percent), other non-steam (less than 0.1 percent), and combined cycle (less than 0.1 percent) units.[80]

As a separate analysis, EPA also compared total compliance costs to the total cost of building and operating a new coal unit on an annualized basis. EPA obtained the overnight[81] capital and O&M costs of building and operating a new scrubbed coal unit used in the Energy Information Administration's Annual Energy Outlook 2011; these costs were estimated for a new dual-unit plant with a total generation capacity of 1,300 MW. Table XI–8 shows capital and O&M costs of building and operating a new coal unit and contrasts these costs with the incremental costs associated with the preferred option (i.e., Option 4 for new sources).

TABLE XI–8—COMPARISON OF INCREMENTAL COMPLIANCE COSTS WITH COSTS FOR NEW COAL-FIRED STEAM ELECTRIC UNITS

Cost component	Costs of new coal generation ($2010/MW)[a]	Incremental compliance costs ($2010/MW)[b]	Percent of new generation cost
Capital	$2,981,947	$19,911–$21,773	0.7–0.7
Annual O&M	66,427	2,281–$3,093	3.4–4.7
Total Annualized Costs	329,487	4,037–$5,013	1.2–1.5

[a] Source: New unit total cost value from Table 8.2 EIA NEMS Electricity Market Module. AEO 2011 Documentation. Available at *http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf*. Capital costs are based on the total overnight costs for new scrubbed coal dual-unit plant, 1,300 MW capacity coming online in 2014. EPA restated costs in 2010 dollars. Total annual O&M costs assume 90% capacity utilization.
[b] Incremental costs for new 1300 MW unit for Option 4. Range represents the costs for a new unit at an existing plant (lower bound) and new unit at newly constructed plant (upper bound).

The comparison suggests that compliance with the proposed ELGs represents a relatively small fraction of overnight capital costs of a new unit (less than 1 percent) and a somewhat higher, but still small (less than 5 percent), fraction of non-fuel O&M costs. On an annualized basis, compliance costs for the proposed ELGs are 1.2 to 1.5 percent of annualized costs for a new plant.

Based on these two separate assessments, EPA finds no evidence that the incremental compliance costs associated with the proposed NSPS/PSNS present a barrier to entry.

5. Assessment of Potential Electricity Price Effects

EPA assessed the potential electricity price effects of this proposed rule in two ways: (1) an assessment of the potential annual increase in household electricity costs and (2) an assessment of the potential annual increase in electricity costs per MWh of total electricity sales.

[80] Other steam generation includes biomass, landfill gas, fossil waste, municipal solid waste, non-solid waste, tires, and geothermal. Other non-steam generation includes wind, solar, pumped storage, and fuel cell.

[81] As defined by the Energy Information Administration, "overnight cost" is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid any impact of project delays and of financing issues and assumptions on estimated costs.

The analysis assumes, for analytic convenience as a worst-case scenario, that *all* compliance costs will be passed through on a pre-tax basis as increased electricity prices as opposed to the treatment in the plant- and entity-level analyses discussed in Section XI.D.1 above, which assume that *none* of the compliance costs will be passed to consumers through electricity rate increases.

a. Cost to Residential Households

Using the assumptions outlined above, EPA estimated the potential annual increase in electricity costs per household, by North American Electric Reliability Corporation (NERC) region. The analysis uses the total annualized pre-tax compliance cost per megawatt hour (MWh) for the year 2014 (in 2010 dollars), in conjunction with the reported total electricity sales quantity for each NERC region for 2009. This analysis also uses the quantity of residential electricity sales per household in 2009. To calculate the average cost per household, by region, EPA divided total compliance costs for each NERC region by the reported total MWh of sales within the region. The potential annual cost impact per household was then calculated by multiplying the estimated average cost per MWh by the average MWh per household, by NERC region.[82] Details of this analysis are presented in Chapter 7 of the RIA.

Table XI–9 summarizes the annual household impact results for each regulatory option, by NERC region. The results for Option 3a show the average annual cost per residential household increasing by $0 to $1.69 depending on the region, with a national average of $0.48. This represents a monthly increase of $0.04 for the typical household. For Option 3b, the results show the average annual cost per residential household increasing by $0 to $2.29, with a national average of $0.75, or $0.06 per month. For Option 3, the average annual cost per residential household increases by $0 to $4.40, with a national average of $1.59, or $0.13 per month. Finally, for Option 4a, the average annual cost per residential household increases by $0 to $7.22, depending on the region, with a national average of $2.69, or $0.22 per month.

TABLE XI–9—AVERAGE ANNUAL COST BURDEN PER RESIDENTIAL HOUSEHOLD IN 2014 BY REGULATORY OPTION AND NERC REGION

[2010$] [a]

NERC Region	Option 3a	Option 3b	Option 1	Option 2	Option 3	Option 4a	Option 4	Option 5
ASCC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ECAR	1.69	2.29	1.82	2.71	4.40	7.22	10.08	16.86
ERCOT	0.00	0.42	1.22	1.73	1.73	2.60	2.79	5.76
FRCC	0.00	0.00	0.18	0.67	0.67	0.67	0.99	4.32
HICC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MAAC	0.00	0.00	0.06	0.32	0.32	0.97	2.04	3.52
MAIN	0.31	0.31	0.48	0.69	1.01	2.55	4.63	6.16
MAPP	0.01	0.01	0.97	1.30	1.32	2.04	3.23	5.58
NPCC	0.00	0.00	0.03	0.08	0.08	0.08	0.49	0.67
SERC	1.09	2.00	1.63	2.19	3.28	4.98	6.47	10.81
SPP	0.05	0.14	0.61	0.96	1.01	2.85	4.43	6.30
WECC	0.05	0.05	0.02	0.03	0.08	0.23	0.53	0.59
U.S.	0.48	0.75	0.75	1.12	1.59	2.69	3.89	6.46

[a] The rate impact analysis maintains the counterfactual, conservative assumption of 100 percent pass-through to electricity consumers.

As stated above, this analysis assumes that all of the compliance costs (100 percent) will be passed onto consumers through increased electricity rates. However, plants and owning entities are likely to absorb some of these costs, thereby reducing the impact of the proposed ELGs on electricity consumers. At the same time, EPA recognizes that electric generators that operate as regulated public utilities are generally permitted to pass on environmental compliance costs as rate increases to consumers. To evaluate the sensitivity of the results to the pass-through assumption, EPA analyzed alternative scenarios including cases where only half (50 percent) of the incremental compliance costs are passed onto consumers. Appendix B of the RIA report presents the results of this sensitivity analysis. The results show smaller impacts on electricity rates, commensurate with the smaller fraction of the compliance costs that are passed onto consumers.

b. Compliance Costs per Unit of Electricity Sales

As an additional measure of the potential electricity price effects associated with the proposed ELGs, EPA also assessed the potential increase in electricity prices to all consumer groups (residential, commercial, industrial, and transportation), again making a counterfactual, conservative assumption of a 100 percent pass-through of compliance costs. This assessment uses as its basis the cost of the regulatory options per unit of electricity sold.

EPA used two data inputs in this analysis (1) total pre-tax compliance cost by NERC region, and (2) estimated total electricity sales for 2014, by NERC region. The Agency summed sample-weighted pre-tax annualized compliance costs as of 2014 over complying plants by NERC region to calculate the total estimated annual cost in each region. EPA then calculated the approximate average price impact per unit of electricity consumption by dividing total compliance costs by the reported total MWh of sales in each NERC region. Details of this analysis are presented in Chapter 7 of the RIA report.

As reported in Table XI–10, on average, across the United States, Option 5 results in the highest increased compliance cost of 0.059¢ per kWh. Annualized compliance costs (in dollars per KWh sales) associated with Option 3a range from 0¢ to 0.016¢, depending on the region, with a national average of

[82] Some NERC regions have been re-defined over the past few years. The NERC region definitions used in this proposed rule analyses vary by analysis depending on which region definition aligns better with the data elements underlying the analysis.

0.004¢ per KWh. For Option 3b, annualized compliance costs range from 0¢ to 0.022¢, with a national average of 0.007¢ per KWh, whereas Option 3 has a range of 0¢ to 0.042¢ per kWh and a national average of 0.015¢ per kWh and Option 4a has a range of 0¢ to 0.068¢ per kWh and a national average of 0.025¢ per kWh. To determine the potential significance of these compliance costs on electricity prices, EPA compared the per kWh compliance cost to baseline electricity prices by consuming sector, and for the average of the sectors. Across the United States and consuming sectors, Option 3a is estimated to result in the smallest electricity price increase, 0.05 percent; the other preferred BAT and PSES options, Options 3b, 3 and 4a, have estimated increases of 0.08 percent, 0.16 percent and 0.27 percent, respectively.

TABLE XI–10—COMPLIANCE COST PER UNIT OF ELECTRICITY SALES IN 2014 BY REGULATORY OPTION AND NERC REGION

[2010 ¢/KWh Sales] [a]

NERC Region	Option 3a	Option 3b	Option 1	Option 2	Option 3	Option 4a	Option 4	Option 5
ASCC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
ECAR	0.016	0.022	0.017	0.026	0.042	0.068	0.095	0.159
ERCOT	0.000	0.003	0.009	0.012	0.012	0.019	0.020	0.041
FRCC	0.000	0.000	0.001	0.005	0.005	0.005	0.007	0.032
HICC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MAAC	0.000	0.000	0.001	0.003	0.003	0.010	0.021	0.036
MAIN	0.003	0.003	0.005	0.008	0.011	0.028	0.051	0.068
MAPP	0.000	0.000	0.009	0.012	0.013	0.019	0.031	0.053
NPCC	0.000	0.000	0.000	0.001	0.001	0.001	0.007	0.009
SERC	0.008	0.014	0.012	0.016	0.023	0.035	0.046	0.076
SPP	0.000	0.001	0.005	0.008	0.008	0.023	0.036	0.051
WECC	0.001	0.001	0.000	0.000	0.001	0.002	0.006	0.006
U.S.	0.004	0.007	0.007	0.010	0.015	0.025	0.036	0.059

[a] This analysis makes a counterfactual, conservative assumption of 100 percent pass-through to electricity consumers.

As mentioned in the previous section, EPA ran alternative scenarios using an assumption that only half (50 percent) of the incremental compliance costs are passed onto consumers. The results of these alternative scenarios showed commensurately smaller impacts on compliance costs per unit of electricity sold (see Appendix B of the RIA report).

E. Employment Effects

EPA assessed the potential for employment impacts at the national level for the eight regulatory options considered in this action.

1. Methodology

The employment effects analysis estimates employment changes only in the directly regulated electric power industry sector at the national level. This analysis focuses on the longer-term, on-going employment effects of meeting compliance requirements, and accounts for all compliance costs, regardless of their time, duration, or frequency of occurrence. Morgenstern, Pizer and Shih (2000) explore both theoretically and empirically the relationship between employment and compliance costs of environmental regulation. Morgenstern et al. identify three separate components of the employment change within a regulated industry in response to a regulation. First, complying with environmental regulations causes higher production costs which raises market prices, higher prices reduce consumption (and production) reducing demand for labor within the regulated industry (‘‘demand effect’’). Second, as costs go up, to produce the same level of output, plants add more capital and labor. For example, pollution abatement activities require additional labor services to produce the same level of output (‘‘cost effect’’). Third, post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) (‘‘factor-shift effect’’). The demand effect is unambiguously negative, the cost effect is unambiguously positive and the factor-shift effect could be positive or negative making the total effect theoretically indeterminate. In addition, Morgenstern et al. also estimate an empirical model for four highly polluting/regulated industries to examine the effect of higher abatement costs from regulation on employment. They conclude that increased abatement expenditures generally do not cause a significant change in employment. More specifically, their results show that, on average across their industries, each additional $1 million spending on pollution abatement (in $1987 dollars) results in a (statistically insignificant) net increase of 1.5 jobs (95 percent confidence interval: −2.9 to + 6.0).

2. Findings

Table XI–11 presents the estimated change, based on the Morgenstern et al. results, in employment in the electric power industry due to the proposed ELGs under each of the eight regulatory options. The table lists the options in increasing order of employment effects. Overall, in the aggregate and by a specific employment effect, Option 1 is projected to have the smallest effect and Option 5 is projected to have the largest effect on employment. The Demand Effect is projected to result in a decline in the number of jobs, while the Cost Effect and Factor Shift Effect are projected to result in an increase in the number of jobs.

EPA estimated an average annual increase of 168 jobs under proposed Option 3a for existing sources. For proposed Option 3b, the average annual increase is estimated at 255 jobs, whereas Options 3 and 4a have estimated increases of 519 jobs and 865 jobs, respectively. Because the electric utility industry is more capital intensive and less labor intensive than the industries examined in Morganstern, Pizer and Shih, in addition to the employment estimates being statistically not distinguishable from the effect being zero, the estimates presented here are likely to be over-estimated. Chapter 6 of the RIA report describes the methodologies and results in greater detail.

TABLE XI–11—RESULTS OF ONGOING EMPLOYMENT EFFECTS ON THE ELECTRIC POWER INDUSTRY SECTOR (NUMBER OF JOBS) [a b]

Regulatory option	Employment effect	Total annual average employment effect
Option 3a	Cost	262
	Factor Shift	291
	Demand	−386
	Total	168
Option 1	Cost	380
	Factor Shift	421
	Demand	−559
	Total	243
Option 3b	Cost	399
	Factor Shift	441
	Demand	−586
	Total	255
Option 2	Cost	548
	Factor Shift	607
	Demand	−806
	Total	548
Option 3	Cost	810
	Factor Shift	897
	Demand	−1,192
	Total	519
Option 4a	Cost	1,351
	Factor Shift	1,496
	Demand	−1,988
	Total	865
Option 4	Cost	1,956
	Factor Shift	2,166
	Demand	−2,878
	Total	1,253
Option 5	Cost	3,298
	Factor Shift	3,653
	Demand	−4,852
	Total	2,112

[a] Source: Morgenstern, Pizer, and Shih (2002).

[c] Coefficients from Table III, p. 427, for the Cost, Demand, Factor Shift and Total Effects were multiplied by the annualized cost of the proposed ELGs calculated as part of the social cost analysis (see Section XI.C) during the 24-year analysis period and re-stated in 1987 dollars, by the coefficient for the net increase in jobs.

Number of jobs is the average number of production workers plus other employees. The definition for employment used by the U.S. Census Bureau's Annual Survey of Manufacturers can be found here: *http://www.census.gov/manufacturing/asm/definitions/index.html.*

XII. Cost-Effectiveness Analysis

EPA performed a cost-effectiveness analysis of the regulatory options for existing plants. EPA often uses cost-effectiveness analysis in the development/revision of effluent limitations guidelines and standards to evaluate the relative efficiency of alternative regulatory options in removing toxic pollutants from the effluent discharges to the nation's waters. Although not required by the Clean Water Act, cost-effectiveness analysis is a useful tool for evaluating regulatory options that address toxic pollutants.

A. Methodology

The cost-effectiveness of a regulatory option is defined as the incremental annual cost (in 1981 constant dollars) per incremental toxic-weighted pollutant removals for that option. This definition includes the following concepts:

Toxic-weighted removals. Pollutants differ in their toxicity. Therefore, the estimated reductions in pollution discharges, or pollutant removals, are adjusted for toxicity by multiplying the estimated removal quantity for each pollutant by a normalizing toxic weight (toxic weighting factor). The toxic weight for each pollutant measures its toxicity relative to copper, with more toxic pollutants having higher toxic weights. The use of toxic weights allows the removals of different pollutants to be expressed on a constant toxicity basis as toxic pound-equivalents (lb-eq). The removal quantities for the different pollutants can then be summed to yield an aggregate measure of the reduction in toxicity-normalized pollutant discharges that is achieved by a regulatory option. The cost-effectiveness analysis does not address the removal of conventional pollutants (e.g., total suspended solids) or nutrients (nitrogen, phosphorus), nor does it address the removal of bulk parameters, such as COD. In the case of indirect dischargers, the removal also accounts for the effectiveness of treatment at publicly owned treatment works (POTW) and reflects the toxic-weighted pounds remaining after POTW treatment.

Annual costs. The costs used in the cost-effectiveness analysis are the estimated annualized pre-tax costs to comply with the alternative regulatory options (refer to Section XI for a discussion of the annualized compliance costs). These costs to plants to remove the pollutants will be less because the costs are tax deductible. The annual costs include the annualized capital outlays for equipment and recurring expenses for operating and maintaining compliance equipment, meeting monitoring requirements, etc.

Incremental calculations. The incremental values are the changes in total annual compliance costs and changes in pollutant removals as one moves to a regulatory option from the next less stringent regulatory option, or from the baseline for the least stringent option analyzed, where regulatory options are ranked by increasing levels of toxic-weighted removals. The resulting cost-effectiveness values for a given option are, therefore, expressed relative to another option or, for the least stringent option considered, relative to the baseline.

The result of the cost-effectiveness calculation represents the unit cost of removing the next pound-equivalent of pollutants and is expressed in constant 1981 dollars per toxic pound-equivalent removed ($/lb-eq) to allow comparisons with the reported cost effectiveness of other effluent guidelines, which use 1981 dollars.

EPA performed the cost-effectiveness analysis for the eight regulatory options for the proposed Steam Electric ELGs separately for existing direct dischargers (subject to BAT) and indirect dischargers (subject to PSES). The following sections summarize the results. Note that the same plant may be categorized as a direct discharger for one of the wastestreams it generates and as an indirect discharger for another.

B. Cost-Effectiveness Analysis for Direct Dischargers

Table XII–1 summarizes the cost-effectiveness analysis for the BAT regulatory options applicable to direct dischargers. The table lists the options in increasing order of total annual toxic-weighted pollutant removals.

TABLE XII–1—COST-EFFECTIVENESS OF REMOVING TOXIC POLLUTANTS FOR DIRECT DISCHARGERS [a]

Option	Annual pre-tax compliance costs (million, 1981$)		Total annual toxic-weighted pollutant removals (000 lb-eq)		Cost effectiveness (1981$/lb-eq)	
	Option total cost	Incremental cost	Option total removals	Incremental removals	Option cost effectiveness	Incremental cost effectiveness
Option 1	$105.6	$105.6	1,530,719	1,530,719	$69	$69
Option 3a	67.5	−38.1	2,488,470	957,751	27	−40
Option 2	156.0	88.5	2,603,628	115,158	60	768
Option 3b	106.3	−49.7	3,396,653	793,025	31	−63
Option 3	223.5	117.2	5,092,098	1,695,445	44	69
Option 4a	378.7	155.2	6,664,693	1,572,595	57	99
Option 4	547.9	169.2	7,831,298	1,166,605	70	145
Option 5	906.5	358.5	8,200,804	369,506	111	970

[a] Options are ranked by increasing levels of total annual toxic-weighted removals.

As shown in Table XII–1, the proposed technology bases for BAT have a cost-effectiveness ratio of $27/lb-eq, $31/lb-eq, $44/lb-eq, and $57/lb-eq, respectively for Options 3a, 3b, 3 and 4a ($1981). These cost-effectiveness ratios are well within the range of cost-effectiveness ratios for BAT of other industries. A review of approximately 25 of the most recently promulgated or revised BAT limitations shows BAT cost-effectiveness ranging from less than $1/lb-eq (Inorganic Chemicals) to $404/lb-eq (Electrical and Electronic Components), in 1981 dollars.

C. Cost-Effectiveness Analysis for Indirect Dischargers

Table XII–2 summarizes the cost-effectiveness analysis for the PSES regulatory options applicable to indirect dischargers. Toxic-weighted pollutant removals for indirect dischargers account for POTW removal efficiencies. The table lists the options in increasing order of total annual toxic-weighted pollutant removals.

TABLE XII–2—COST-EFFECTIVENESS OF REMOVING TOXIC POLLUTANTS FOR INDIRECT DISCHARGERS [a]

Option	Annual pre-tax compliance costs (million, 1981$)		Total annual toxic-weighted pollutant removals (000 lb–eq)		Cost effectiveness (1981$/lb-eq)	
	Option total cost	Incremental cost	Option total removals	Incremental removals	Option cost effectiveness	Incremental cost effectiveness
Option 3a	$0.0	$0.0	0	0		
Option 3b	0.0	0.0	0	0		
Option 1	1.2	1.2	3,540	3,540	$345	$345
Option 2	2.0	0.7	11,711	8,171	168	92
Option 3	2.0	0.0	11,711	0	168	
Option 4a	2.0	0.0	11,711	0	168	
Option 4	3.6	1.6	15,532	3,821	233	430
Option 5	8.1	4.5	18,297	2,765	445	1,636

[a] Options are ranked by increasing levels of total annual toxic-weighted removals.

As shown in Table XII–2, there are no indirect dischargers that would incur compliance costs or result in incremental pollutant removals under Options 3a and 3b, whereas Options 3 and 4a both have a cost effectiveness of $168/lb-eq ($1981). The cost-effectiveness of Options 3 and 4a is within the range of cost-effectiveness for PSES of other industries. A review of approximately 25 of the most recently promulgated or revised categorical pretreatment standards shows PSES cost-effectiveness ranging from less than $1/lb-eq (Inorganic Chemicals) to $380/lb-eq (Transportation Equipment Cleaning), in 1981 dollars.

XIII. Environmental Assessment

This section describes the environmental assessment conducted in support of this rulemaking. The environmental assessment reviewed currently available literature on the documented environmental and human health impacts of combustion wastewaters and conducted modeling to determine the cumulative impacts caused by the universe of steam electric power plants proposed to be regulated under this effluent limitations guidelines and standards. Modeling calculated both the impacts at baseline conditions (current conditions), and the improvements that will result after implementation of the different potential control options. The environmental improvements discussed in Section XIII.A below are those for the preferred BAT and PSES regulatory options (Option 3a, Option 3b, Option 3, and Option 4a).

A complete review of the scientific literature and a full description of EPA's modeling analysis (including the results for all other control options) are provided in the *Environmental Assessment of the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.*

Current scientific literature indicates that combustion wastewaters such as fly ash and bottom ash transport water, FGD wastewater, and combustion residual leachate are toxic wastes and are causing significant detrimental environmental and human health impacts. Documented environmental impacts from exposure to these wastes reveals that the threat posed to human health, wildlife and the environment is a widespread problem that is not isolated to a few unique locations or circumstances. Documented instances of drinking water maximum contaminant level (MCL) exceedances near steam electric power plants and the issuance of fish advisories in waters that receive combustion wastewater indicates the likely threat of human health impacts from these wastestreams (see Section 3.4.2 of the Environmental Assessment). In addition, one recent study provides confirming empirical evidence that toxic wastes are currently damaging aquatic life and accumulating in the environment and will only get worse.[83]

Ecological impacts include both acute (e.g., fish kills) and chronic effects (e.g., malformations, and metabolic, hormonal, and behavioral disorders) upon biota within the receiving water and the surrounding environment. Bioaccumulative toxic metals (e.g., selenium, mercury, and arsenic) are commonly cited as the primary cause for ecological damage following exposure to combustion wastewater. Selenium is the most frequently cited metal associated with environmental impacts following exposure to combustion wastewater discharges. Documented selenium-related impacts include lethal effects such as fish kills and sublethal effects such as histopathological changes (i.e., accumulation of trace elements in tissue) and damage to reproductive and developmental success. Other metals in combustion wastewater discharges such as arsenic, cadmium, chromium, copper, and lead have also been documented as causing sublethal effects such as changes to morphology (e.g., fin erosion, oral deformities), behavior (e.g., swimming ability, ability to catch prey, ability to escape from predators), and metabolism that can negatively affect long-term survival. Combined, these impacts can drastically alter aquatic populations and communities and the surrounding ecosystems that rely on them.

Recovery of the environment from exposure to combustion wastewater discharges can be extremely slow due to the accumulation and continued cycling of contaminants within the ecosystem and the potential to alter ecological processes, such as population diversity and community dynamics in the surrounding ecosystems. The ability of aquatic and adjacent terrestrial environments to recover from even short periods of exposure to these wastes depends on, among other factors, the distance from the discharge, the pollutant loadings, pollutant residence time, and the time elapsed since exposure. In particular, accumulation of metals in sediments can make recovery of aquatic systems following exposure to combustion wastewater discharges exceptionally slow due to the potential for resuspension in the water column and for benthic organisms to provide a pathway for exposure long after discharges have ended. In addition, metals such as selenium and arsenic bioaccumulate in organisms exposed to combustion wastewater discharges further complicating the potential magnitude of impacts these wastes pose.

EPA identified several cases in the literature where metals from combustion wastewater discharges bioaccumulated to toxic levels in organisms inhabiting aquatic environments even with low concentrations of these contaminants. The strong bioaccumulative properties of the pollutants, in conjunction with long residence times, emphasize the threat these wastes present to the local environment as many of the impacts may not be fully realized for years to come.

In addition to the bioaccumulative and toxic properties of the pollutants in combustion wastewaters, the total pollutant loadings associated with these discharges are large (see Section IX). EPA estimates that discharges from steam electric power plants alone contribute 50 to 60 percent of the reported toxic-weighted pollutant loadings of the combined discharges of all industrial categories currently regulated in the U.S. Further, many steam electric power plants discharge to sensitive environments where pollutant loadings contribute to reduced water quality (e.g., Great Lakes, valuable estuaries, 303(d) listed waters, drinking water sources, and waters with fish consumption advisories).

EPA has determined that 25 percent of surface waters that receive combustion wastewater discharges are impaired for a pollutant associated with combustion wastewater; 38 percent of surface waters are under a fish advisory for a pollutant associated with combustion wastewater. In addition to the concurrence of combustion wastewater discharges in close proximity to sensitive environments, EPA has identified over 120 steam electric power plants with documented environmental impacts to surface water and ground water environments following exposure to combustion wastewater, which is further evidence these wastes are of great concern. While in the past these cases may have been assumed to be anomalies, an increasing amount of evidence indicates that the characteristics contributing to the documented impact (e.g., size of the pollutant loadings, type of pollutant present in the waste, plant operations, and wastewater handling techniques) are common among power plant discharge locations. Further, as explained earlier, these documented impacts do not yet reflect the increased pollutant loadings associated with increasing use of air pollution controls. This, when coupled with the potential for long-term persistent impacts due to bioaccumulative pollutants, indicates that these impacts most likely are occurring in other locations around the country even though they have not yet been documented. This suggests that the magnitude of the environmental impact of combustion wastewater discharges is potentially greater than the literature estimates.

In addition, EPA has identified other potential impacts from combustion wastewater discharges. Steam electric plants also discharge bromide in large quantities. Bromide in wastewater discharges from steam electric plants located upstream from a drinking water intake has been associated with the formation of trihalomethanes (THMs) and haloacetic acids (HAAs) when it is exposed to chlorination disinfection processes in drinking water treatment plants. Bromate, a disinfection byproduct (DBP) associated with drinking water treatment plants that employ ozonation may also increase under the influence of increased bromide in the source water. Human exposure to THMs and DBPs in chlorinated drinking water is associated with bladder cancer.

Based on the documented environmental impacts discussed in the literature, EPA identified several key environmental and human health concerns and pathways of exposure to evaluate in the environmental assessment. These included changes in surface water, sediment, and ground water quality; toxic effects on aquatic life; toxic metal bioaccumulation in fish and in piscivorous wildlife (e.g., minks and bald eagles); toxic metal bioaccumulation in fish consumed by humans; and contamination of ground water drinking water resources.

EPA developed a three-part receiving water model to quantify changes in plant-specific impacts to surface waters, wildlife, and human health from pollutant reductions associated with the regulatory options discussed in Section VIII for a subset of evaluated wastestreams from steam electric power plants (i.e., fly ash and bottom ash transport water, FGD wastewater, and leachate). EPA considered the type of

[83] Ruhl, L., A. Vengosh, G.S. Dwyer, H. Hsu-Kim, G. Schwartz, A. Romanski, and S.D. Smith. 2012. The Impact of Coal Combustion Residue Effluent on Water Resources: A North Carolina Example. Environmental Science and Technology. DCN SE01984.

receiving waters commonly impacted by steam electric power plants and the pollutants typically found in the evaluated wastestreams in selecting the appropriate methodologies for the quantitative Environmental Assessment analysis. EPA designed the model to quantify the environmental impact within rivers/streams and lakes/ponds (including reservoirs) based on the finding that 94 percent of the power plant outfalls discharge to these types of surface waters. EPA focused the modeling on toxic metals due to the total mass loadings discharged, potential for toxic effects to wildlife and human health, and potential for bioaccumulation within the ecosystem. EPA addressed environmental impacts from nutrients, in a separate analysis discussed in Section XIII.E.

EPA's environmental assessment modeling includes three interrelated models: 1) a receiving water-scale water quality model; 2) a receiving water-scale wildlife model; and 3) a receiving water-scale human health model. Each of these models evaluates changes in environmental and human health effects under baseline conditions and five of the regulatory options discussed in Section VIII of this preamble (Options 1, 2, 3, 4, and 5). The receiving water-scale water quality model estimates the concentration of metals (i.e., arsenic, cadmium, chromium VI, copper, lead, mercury, nickel, selenium, thallium, zinc) in the surface waters and sediments in the immediate discharge zone (i.e., approximately one to 10 kilometers [km] from the outfall) for steam electric power plants with direct discharge loadings included in the costs and loadings analysis (see Section IX). EPA compared modeled receiving water concentrations based on pollutant loadings from the evaluated wastestreams against National Recommended Water Quality Criteria (NRWQC) and Maximum Contaminant Levels (MCLs) to assess changes in receiving water quality. The wildlife model evaluates the potential impact that water and sediment concentrations pose to aquatic life, calculates the metal concentrations in exposed fish populations, and evaluates the potential impact to wildlife (minks and eagles) from consumption of fish. The human health model calculates potential threat to cause non-cancer health effects and cancer risks to human populations from the consumption of fish exposed to discharges of the evaluated wastestreams. In addition to the immediate receiving water analysis, EPA modeled receiving water concentrations downstream from steam electric discharges using EPA's Risk-Screening Environmental Indicators (RSEI) model and used the wildlife and human health models to calculate metal concentrations in exposed fish populations and human exposure doses from fish consumption in surface waters downstream from steam electric discharges. EPA compared downstream receiving water concentrations, fish tissue concentrations, and human exposure to water quality, wildlife, and non-cancer and cancer benchmarks to assess the number of improved river miles associated with the different options for this proposed rule.

EPA did not perform modeling to evaluate changes in environmental and human health effects under Option 3a, Option 3b, or Option 4a. To estimate the environmental improvements under these three options, the Agency compared their pollutant load reductions to those of Option 3 (whose reductions would be greater than those of Option 3a and Option 3b, and less than those of Option 4a) and applied corresponding adjustments to the modeled environmental improvements under Option 3 to approximate those of the three un-modeled options.

EPA expects a number of environmental and ecological improvements and reduced impacts to wildlife and human receptors to result from reductions in effluent loadings examined for the different options discussed in this proposed rule. In particular, the Environmental Assessment evaluated the following: a) improvements in water quality, b) reduction in impacts to wildlife, c) reduction in number of receiving waters with potential human health cancer risks, d) reductions in number of receiving waters with potential to cause non-cancer human health effects, e) reduction in nutrient impacts, f) reduction in other environmental impacts, and g) unquantified environmental improvements.

A. Improvements in Surface Water and Ground Water Quality

The reduced pollutant loadings associated with the preferred options (Option 3a, Option 3b, Option 3, and Option 4a) would lead to reduced contamination levels in surface waters and sediments. EPA estimated that reduced pollutant loadings to surface waters associated with Option 3a would significantly improve water quality by reducing metal concentrations by up to 33 percent on average within the immediate receiving waters. Option 3b, Option 3, and Option 4a would achieve average reductions of up to 36 percent, 48 percent, and 60 percent, respectively. The pollutants with the greatest number of water quality standard (NRWQC or MCL) exceedances under baseline pollutant loadings include: total arsenic, total thallium, dissolved cadmium, and total selenium. EPA determined that 49 percent of the immediate receiving waters exceeded a water quality standard under baseline loadings. EPA estimates the number of immediate receiving waters with aquatic life exceedances, which are driven by dissolved cadmium and total selenium concentrations, would be reduced by up to 29 percent for both Option 3a and Option 3b, up to 35 percent for Option 3, and up to 55 percent for Option 4a under the post-compliance pollutant loadings. EPA also estimates that the number of immediate receiving waters with human health water quality standards exceedances, primarily driven by total arsenic and total thallium concentrations, would be reduced by up to 14 percent for Option 3a, up to 15 percent for Option 3b, up to 18 percent for Option 3, and up to 41 percent for Option 4a.

Selenium was one of the primary pollutants identified in the literature as causing documented environmental impacts to fish and wildlife. EPA calculates that total selenium receiving water concentrations would be reduced by 33 percent on average under Option 3a, 36 percent on average under Option 3b, 48 percent on average under Option 3, and 60 percent on average under Option 4a. This would reduce the number of immediate receiving waters exceeding the freshwater chronic criteria for selenium by 38 percent under Option 3a, 40 percent under Option 3b, 55 percent under Option 3, and 67 percent under Option 4a. EPA estimates that up to 3,643 river miles (Option 3a), 3,862 river miles (Option 3b), 4,830 river miles (Option 3), and 6,633 river miles (Option 4a) downstream from steam electric discharges would no longer exceed aquatic life and human health NRWQC or MCL standards under the post-compliance pollutant loadings.

The preferred options would both reduce ground water contamination levels and improve the availability of ground water resources by reducing the future leaching of pollutants from steam electric impoundments to groundwater aquifers. Section XIV provides additional details on the benefits analysis of these ground water improvements.

B. Reduced Impacts to Wildlife

EPA calculates that the number of immediate receiving waterbodies with potential impacts to wildlife would be reduced by up to 23 percent under Option 3a, up to 24 percent under Option 3b, up to 30 percent under Option 3, and up to 51 percent under Option 4a. EPA developed the receiving waters wildlife model to quantify the impacts to wildlife that consume fish exposed to steam electric discharges. EPA selected minks and eagles as representative indicator species to evaluate the impact discharges of the evaluated wastestreams posed to birds and mammals that consume fish. EPA selected minks and eagles based on their national population distribution and the fact that a majority of their diet is comprised of fish. EPA modeled fish tissue concentrations for the immediate and downstream receiving waters and compared those concentrations to no effect hazard concentrations (NEHC) benchmarks developed by the U.S. Geological Survey (USGS) that indicate potential impacts to piscivorous (i.e., fish eating) wildlife. The NEHC benchmarks developed by the USGS are based on ''no observed adverse effect levels'' (NOAELs), which were derived from adult dietary exposure or tissue concentration studies and based primarily on reproductive endpoints.

EPA determined that combustion wastewater discharges into lakes pose the greatest risk to piscivorous wildlife, with approximately 78 percent of lakes compared to 39 percent of rivers exceeding a NEHC benchmark for minks or eagles under baseline pollutant loadings. Mercury and selenium, and to a lesser extent cadmium and zinc, were the primary pollutants with greatest number of receiving waters with wildlife NEHC benchmark exceedances. EPA estimates that the preferred options would reduce the number of immediate receiving waters exceeding the mercury NEHC for minks and eagles by up to 24 percent under Option 3a, up to 26 percent under Option 3b, up to 33 percent under Option 3, and up to 52 percent under Option 4a. For selenium, EPA estimates that the number of immediate receiving waters exceeding the selenium NEHC would be reduced by up to 29 percent under Option 3a, up to 31 percent under Option 3b, up to 42 percent under Option 3, and up to 56 percent under Option 4a. This indicates that the preferred options would reduce the bioaccumulative impact of the evaluated wastestreams in the broader ecosystem. EPA estimates that up to 4,135 river miles (Option 3a), up to 4,360 river miles (Option 3b), up to 5,300 river miles (Option 3), and up to 8,206 river miles (Option 4a) downstream from steam electric discharges would no longer exceed a NEHC benchmark for minks or eagles under the post-compliance pollutant loadings.

In addition, EPA estimates that the upgrades to water quality (i.e., reductions in aquatic life NRWQC exceedances) discussed above would improve aquatic and wildlife habitats in the immediate and downstream receiving waters from steam electric discharges. EPA determined that these water quality and habitat improvements would enhance efforts to protect threatened and endangered species. EPA identified eight species with a high vulnerability to changes in water quality whose recovery would be expected to be enhanced by the post-compliance pollutant loading reductions associated with the preferred options.

C. Reduced Human Health Cancer Risk

EPA estimates that reductions in arsenic loadings from the preferred options would result in a reduction in potential cancer risks to humans that consume fish exposed to discharges of the evaluated wastestreams. The human health model calculates the potential cancer risk for select age groups and consumption categories (i.e., child and adult recreational fishers and child and adult subsistence fishers) based on assumptions of arsenic bioaccumulation in fish exposed to discharges of the evaluated wastestreams. Under baseline pollutant loadings, EPA determined that up to 9 percent of immediate receiving waters contain fish contaminated with inorganic arsenic that would present cancer risks above the 1-in-a-million threshold for one or more of the cohorts evaluated. EPA determined that, depending on the cohort, immediate receiving waters with cancer risks above the 1-in-a-million threshold would be reduced by up to 40 percent (Option 3a), up to 60 percent (Option 3b and Option 3), and up to 80 percent (Option 4a) under post-compliance loadings. In addition, EPA estimates that up to 266 river miles, depending on the cohort, downstream from the steam electric discharges contain fish contaminated with inorganic arsenic that would present cancer risks above the 1-in-a-million threshold. Under the post-compliance pollutant loadings associated with the preferred options, EPA estimates that up to 111 river miles (Option 3a), up to 116 river miles (Option 3b), up to 133 river miles (Option 3), and up to 169 river miles (Option 4a) downstream from steam electric discharges would no longer contain fish contaminated with inorganic arsenic that would present cancer risks above the 1-in-a-million threshold for adult subsistence fishers.

D. Reduced Threat of Non-Cancer Human Health Effects

Exposure to metals poses risk of systemic and other effects to humans, including effects on the circulatory, respiratory, or digestive systems and neurological and developmental effects. The preferred options are estimated to reduce the number of receiving waters with potential to cause non-cancer health effects in humans who consume fish exposed to discharges of the evaluated wastestreams. The human health model calculates the number of immediate receiving waters with the potential to cause non-cancer health effects in select age groups and consumption categories (i.e., child and adult recreational fishers and child and adult subsistence fishers) based on assumptions of metal bioaccumulation in fish exposed to discharges of the evaluated wastestreams. Depending on the cohort, EPA calculates that exceedances of non-cancer reference doses from the consumption of fish would decrease in up to 19 percent of surface waters (Option 3a), up to 21 percent of surface waters (Option 3b), up to 26 percent of surface waters (Option 3), and up to 53 percent of surface waters (Option 4a) immediately receiving discharges of the evaluated wastestreams. Non-cancer risks are driven by mercury (as methylmercury), total thallium, and total selenium, and to a lesser degree, total cadmium pollutant loadings. Under baseline pollutant loadings, the average daily dose from the consumption of fish in up to 65 percent of immediate receiving waters exceeds the non-cancer reference dose for mercury depending on the cohort. Under post-compliance loadings, exceedances of the non-cancer mercury reference dose would decrease in up to 21 percent (Option 3a), up to 22 percent (Option 3b), up to 29 percent (Option 3), and up to 49 percent (Option 4a) of immediate receiving waters, depending on the cohort. In addition, exceedances of total thallium and total selenium non-cancer reference doses would decrease in up to 14 and 50 percent of immediate receiving waters (Option 3a and Option 3b), up to 18 and 69 percent of immediate receiving waters (Option 3), and up to 43 and 77 percent of immediate receiving waters (Option 4a), respectively. EPA also estimates that, under the post-compliance pollutant loadings, exceedances of non-cancer reference doses from the consumption of fish would decrease in up to 4,084 river miles downstream (Option 3a), up to 4,316 river miles downstream (Option 3b), up to 5,400 river miles downstream

(Option 3), and up to 8,087 river miles downstream (Option 4a) for one or more of the cohorts.

In addition to the assessment of non-cancer reference dose exceedances described above, EPA also evaluated the adverse health effects to children who consume fish contaminated with lead from combustion wastewater. EPA estimated the reduction in lead exposure to pre-school children via consumption of contaminated fish tissue and determined that the preferred options would reduce the associated intelligence quotient (IQ) loss among children who live in recreational angler and subsistence fisher households. The preferred options would also be expected to reduce the incidence of other health effects associated with lead exposure among children, including slowed or decayed growth, delinquent and anti-social behavior, metabolic effects, impaired hemesynthesis, anemia, impaired hearing, and cancer. The preferred options would also reduce the IQ loss among children exposed *in-utero* to mercury from maternal fish consumption in populations exposed to immediate and downstream receiving waters from steam electric discharges. Section XIV.B.1.a provides additional details on the benefits analysis of these reduced IQ losses.

EPA expects that the preferred options would result in additional non-cancer human health effects beyond those described above, including reduced health hazards due to exposure to contaminants in waters that are used for recreational purposes (e.g., swimming).

E. Reduced Nutrient Impacts

The primary concern with nutrients in steam electric discharges is the potential for adverse nutrient impacts to occur in water-bodies that receive discharges from multiple plants. Nine percent of surface waters receiving steam electric wastewater discharges are impaired for nutrients. While the current concentration of nitrogen present in steam electric discharges from any individual power plant is relatively low, the total nitrogen loadings from a single plant can be significant due to large wastewater discharge flow rates. Total nutrient loadings from multiple power plants is especially a concern on water bodies that are nutrient impaired or in watersheds that contribute to downstream nutrient problems.

Excessive nutrient loadings to receiving waters can significantly affect the ecological stability of freshwater and saltwater aquatic systems. Nutrient over-enrichment of surface waters can stimulate excessive plant growth that can obstruct sunlight penetration and increase turbidity, which can result in the death of bottom-dwelling aquatic plants. Higher nutrient loadings from steam electric discharges could result in the eutrophication of waters and the formation of hazardous algal blooms. An additional concern with nutrients in steam electric discharges is the potential for the total nitrogen loadings from plants to increase in the future as air pollution limits become stricter and the use of air pollution controls increases.

EPA projects that the preferred options would reduce total nutrient loadings by 39 percent (Option 3a), by 41 percent (Option 3b), by 53 percent (Option 3), and by 66 percent (Option 4a) and improve overall water quality. EPA used the SPARROW (SPAtially Referenced Regressions On Watershed attributes) model to calculate immediate receiving water concentrations under baseline conditions and under five of the regulatory options discussed in Section VIII of this preamble (Options 1, 2, 3, 4, and 5) to analyze benefits related to improvements in water quality. EPA used these concentrations to develop sub-indices for a water quality index (WQI), a value that translates water quality measurements, gathered for multiple parameters that represent various aspects of water quality, into a single numerical indicator. Section XIV provides additional details on the water quality benefits analysis of nutrient reductions.

F. Unquantified Environmental and Human Health Improvements

The above environmental assessment focused on the quantification of environmental improvements within rivers and lakes from post-compliance pollutant loading reductions for toxic metals and excessive nutrients. While extensive, the environmental improvements quantified do not encompass the full range of improvements anticipated to result from the preferred options simply because some of the improvements have no method for measuring a quantifiable or monetizable improvement. EPA expects post-compliance pollutant loading reductions from the preferred options to result in much greater improvements to wildlife, human health and environmental health by reducing the:

- Loadings of bioaccumulative metals to the broader ecosystem resulting in the reduction of long-term exposures and sublethal ecological effects;
- Sublethal chronic effects of toxic metals on aquatic life not captured by the NRWQC;
- Impacts to aquatic and aquatic-dependant wildlife population diversity and community structures;
- Exposure of wildlife to pollutants through direct contact with combustion residuals impoundments and constructed wetlands built as treatment systems at steam electric power plants;
- Adverse health effects in adults resulting from exposure to lead from consumption of contaminated fish tissue; and
- Potential for the formation of hazardous algal blooms.

Data limitations prevented appropriately modeling the scale and complexity of the ecosystem processes potentially impacted by combustion wastewater, resulting in the inability to quantify the improvements listed. However, documented case studies in the literature reinforce that these impacts are common in the environments surrounding steam electric power plants and fully support the conclusion that reducing pollutant loadings will improve overall environmental, human health and wildlife health.

Although the Environmental Assessment quantifies impacts to wildlife that consume fish contaminated with metals from combustion wastewater, it does not capture the full range of exposure pathways through which bioaccumulative metals can enter the surrounding food web. Wildlife can encounter toxic bioaccumulative metals from discharges of the evaluated wastestreams from a variety of exposure pathways such as direct exposure, drinking water, consumption of contaminated vegetation, and consumption of contaminated prey other than fish. Therefore, the quantified improvements underestimate the complete loadings of bioaccumulative metals that can impact wildlife in the ecosystem. EPA anticipates that the post-compliance pollutant loading reductions associated with the preferred options would lower the total amount of toxic bioaccumulative metals entering the food web near steam electric power plants.

EPA also expects the estimated reduction in pollutant loadings to lower the occurrence of sublethal effects associated with many of the pollutants in combustion wastewater that may not be captured by comparisons with NRWQC for aquatic life. Chronic effects such as changes in metabolic rates, decreased growth rates, changes in morphology (e.g., fin erosion, oral deformities), and behavior (e.g., swimming ability, ability to catch prey, ability to escape from predators) that can negatively affect long-term survival, are well documented in the literature in environments near steam electric power plants. Reductions in organism survival rates from the chronic effects such as abnormalities can alter interspecies relationships (e.g., declines in the abundance or quality of prey) and prolong ecosystem recovery. However, these effects were not quantified in the environmental assessment and improvements to wildlife health and survival from the preferred options are, therefore, underestimated. EPA was unable to quantify changes to aquatic and wildlife population diversity and community dynamics; however, population effects (i.e., decline in number and type of organisms present) attributed to exposure to combustion wastewater are well documented in the literature. Changes in aquatic populations can alter the structure of aquatic communities and cause cascading effects within the food web that result in long-term impacts to ecosystem dynamics. EPA expects that post-compliance pollutant loading reductions associated with the preferred options would lower the stressors that can cause alterations in population and community dynamics and improve the overall function of ecosystems surrounding steam electric power plants, as well as help resolve issues faced in other national ecosystem protection programs such as the Great Lakes program, the National Estuaries program and the 303(d) impaired waters program.

EPA anticipates that the expected post-compliance pollutant loading reductions associated with the preferred options would also decrease the environmental impacts to wildlife exposed to pollutants through direct contact with combustion residuals impoundments and constructed wetlands at steam electric power plants. Documented case studies demonstrate that wildlife living in close proximity to combustion residuals impoundments exhibit elevated levels of arsenic, cadmium, chromium, lead, mercury, selenium, strontium, and vanadium. Multiple studies have linked attractive nuisance areas (contaminated areas at a steam electric power plant, such as combustion wastewater surface impoundments, that are attractive to wildlife (place for nesting)) to diminished reproductive success. EPA expects that the post-compliance pollutant loadings would decrease the exposure of wildlife populations to toxic pollutants and reduce the risks for impacts on reproductive success.

G. Other Secondary Improvements

EPA anticipates that other secondary, or ancillary, improvements would occur to other resources that are associated directly or indirectly as a result of the preferred options. These would include aesthetic and recreational improvements, reduced economic impacts such as clean up and treatment costs in response to contamination or impoundment failures, reduced injury associated with pond failures, reduced water usage and reduced air emissions. Section XIV provides additional details on the benefits of these other secondary improvements.

XIV. Benefit Analysis

This section summarizes EPA's estimates of the national environmental benefits expected to result from reduction in pollutant discharges described in Section IX and the resultant environmental effects summarized in Section XIII. The *Benefit and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA) report provides additional details on benefits methodologies and analysis, including uncertainties and limitations.

A. Categories of Benefits Analyzed

Table XIV–1 summarizes benefit categories associated with this proposed rule and notes which categories EPA was able to quantify and monetize. Analyzed benefits fall within six broad categories: human health benefits, ecological conditions and recreational use benefits from surface water quality improvements, market and productivity benefits, air-related benefits, groundwater quality benefits, and water withdrawal benefits. Within these broad categories, EPA was able to assess benefits with varying degrees of completeness and rigor. Where possible, EPA quantified the expected effects and estimated monetary values. However, data limitations and gaps in the understanding of how society values certain water quality changes prevent EPA from quantifying and/or monetizing some benefit categories.

TABLE XIV–1—BENEFIT CATEGORIES ASSOCIATED WITH PROPOSED ELGS

Benefit category	Quantified and monetized	Quantified but not monetized	Neither quantified nor monetized
1. Human Health Benefits from Surface Water Quality Improvements			
Reduced incidence of cancer from arsenic exposure via fish consumption	X		
Reduced non-cancer adverse health effects (e.g., reproductive, immunological, neurological, circulatory, or respiratory toxicity) due to exposure to arsenic from fish consumption		X	
Reduced IQ loss in children from lead exposure via fish consumption	X		
Reduced need for specialized education for children from lead exposure via fish consumption	X		
Reduced adverse health effects in adults from exposure to lead from fish consumption			X
Reduced in-utero mercury exposure via maternal fish consumption	X		
Reduced health hazards from exposure to pollutants in waters used recreationally (e.g., swimming)			X
2. Ecological Conditions and Recreational Use Benefits from Surface Water Quality Improvements			
Benefits from improvements in surface water quality, including: improved aquatic and wildlife habitat; enhanced water-based recreation, including fishing, swimming, boating, and near-water activities; increased aesthetic benefits, such as enhancement of adjoining site amenities (e.g., residing, working, traveling, and owning property near the water[a]; and non-use value (i.e., existence, option, and bequest value from improved ecosystem health)[a]	X		

TABLE XIV–1—BENEFIT CATEGORIES ASSOCIATED WITH PROPOSED ELGS—Continued

Benefit category	Quantified and monetized	Quantified but not monetized	Neither quantified nor monetized
Benefits from improved protection of threatened and endangered species	X		
Reduced sediment contamination			X
3. Groundwater Quality Benefits			
Reduced groundwater contamination	X		
4. Market and Productivity Benefits			
Reduced impoundment failures (monetized benefits include avoided cleanup costs and environmental damages; non-quantified benefits include avoided injury)	X		
Reduced water treatment costs for municipal drinking water, irrigation water, and industrial process			X
Improved commercial fisheries yields			X
Increased tourism and participation in water-based recreation			X
Increased property values from water quality improvements			X
5. Air-Related Benefits			
Reduced mortality from exposure to NO_X, SO_2 and particulate matter ($PM_{2.5}$)	X		
Avoided climate change impacts from CO_2 emissions	X		
6. Benefits from Reduced Water Withdrawals			
Increased availability of groundwater resources	X		

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

The following section discusses EPA's analysis of the benefits that the Agency was able to quantify and monetize (identified in the second column of Table XIV–1). The proposed rule would also result in additional benefits that the Agency was not able to monetize. See the Benefits and Cost Analysis Document for information about these non-monetized benefits.

EPA estimated benefits for five of the eight regulatory options discussed in this preamble (Options 1, 2, 3, 4, and 5). EPA did not estimate the benefits of Options 3a, 3b and 4a. However, EPA used its understanding of the wastestreams and treatment technologies for these options, along with projections of pollutant reductions for all eight options, to estimate total monetized benefits for Options 3a, 3b, and 4a. However, EPA is less confident that this approach would yield reasonable estimates if applied to the individual categories of benefits (water quality, air emissions, avoided impoundment failure cleanup costs, etc) and so has not done so. For these more granular benefits categories, estimates are provided only for Options 1, 2, 3, 4, and 5. Again, these can serve as upper and lower bounds for the individual categories of benefits of Options 3a, 3b, and 4a. Specifically, monetized benefits for Options 3a and 3b are likely to be between those for Options 2 and 3. Similarly, monetized benefits for Option 4a are likely to be between those for Options 3 and 4.

B. Quantification and Monetization of Benefits

1. Human Health Benefits From Surface Water Quality Improvements

Reduced pollutant discharges from steam electric plants generate human health benefits in a number of ways. Pollutants commonly discharged in Steam Electric plant wastewater streams include conventional and toxic pollutants such as arsenic, cadmium, chromium, copper, lead, mercury, selenium, and zinc (steam electric pollutants). Exposure to these pollutants via consumption of fish from affected waterways can cause a wide variety of adverse health effects, including cancer, kidney damage, nervous system damage, fatigue, irritability, liver damage, circulatory damage, vomiting, diarrhea, brain damage, IQ loss, and many others. Because the proposed ELGs would reduce discharges of steam electric pollutants into receiving waterways and downstream areas, they are likely to result in decreased incidences of associated illnesses.

Due to data limitations and uncertainties, EPA is able to monetize only a small subset of the health benefits associated with decreased pollutant discharges from steam electric plants. EPA analyzed the following measures of human health-related benefits: reduced cancer risk due to arsenic exposure from fish consumption, reduced lead-related IQ loss in children from fish consumption, and reduced mercury-related IQ loss in children exposed in-utero due to maternal fish consumption. EPA monetized these human health benefits by estimating the change in the expected number of individuals experiencing adverse human health effects in the populations exposed to steam electric discharges under various regulatory options and valuing these changes using a variety of nonmarket approaches (e.g., cost of illness).

a. Monetized Human Health Benefits

EPA quantified and monetized the following four categories of human health benefits:

- *Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption.* EPA assessed changes in the incidence of cancer cases from consumption of arsenic in the tissue of fish caught in waters affected by steam electric plant discharges. For the baseline and each regulatory option, EPA estimated cancer risk from the consumption of arsenic-contaminated fish for recreational and subsistence anglers and their families. EPA used data on the populations living within 100 miles of affected waterbodies, state-specific average fishing rates, presence of fish consumption advisories, the availability of substitute fishing locations, and average household size to estimate the exposed population for each steam electric facility. To identify the change in number of cancer cases caused by arsenic in this population, EPA used a cancer slope factor (CSF) from EPA's Integrated Risk Information System (IRIS) of 1.5 per mg/kg-day and different fish consumption rates for recreational and subsistence anglers and age cohorts. The Agency valued changes in incidence of cancer cases using a value of a statistical life (VSL) of $8.0 million (2010$), with projections adjusted to account for income growth. This estimate does not include estimates of willingness to pay (WTP) to avoid illness prior to death.

- *Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption.* Children's rapid rate of development makes them more susceptible to neurobehavioral effects from lead exposure. The neurobehavioral effects on children from lead exposure include hyperactivity, behavioral and attention difficulties, delayed mental development, and motor and perceptual skill deficits. EPA assessed benefits of reduced lead exposure from consumption of contaminated fish tissue and the associated IQ loss among children aged 0 to 7. EPA estimated blood-lead levels using EPA's Integrated Exposure, Uptake, and Biokinetic (IEUBK) Model based on daily lead ingestion rates among children from birth to the seventh birthday. Based on blood lead concentrations for children in recreational and subsistence anglers' families, EPA assessed neurobehavioral effects on children using an established dose response relationship between blood lead concentrations and IQ loss. Avoided neurological and cognitive damages are expressed as an increase in overall IQ points in the exposed population. EPA monetized the estimated changes in IQ scores based on the impact of additional IQ points on individuals' future earnings. EPA assumed that each IQ point is worth between $1,156 (following Schwarz (1994) and discounting future earnings at 7 percent) and $13,651 (following Salkever (1995) and discounting future earnings at 3 percent).
- *Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption.* EPA also quantified the reduced incidences of especially high blood-lead levels (above 20 mg/dL) and low IQ scores (<70, or two standard deviations below the mean), and monetized the avoided costs associated with compensatory education that an individual would otherwise need. For this analysis, EPA used the IEUBK model to estimate how many children in the exposed population would have blood lead concentrations above 20 mg/dL, and assumed that 20 percent of those children would have IQ scores below 70. Based on education cost data from the United States Department of Education, EPA assumed that the incremental cost of special education for these individuals and ages 7 through 18 would be approximately $157,000 per child at 3 percent discount rate, and $125,500 per child at 7 percent discount rate.
- *Benefits of Reduced In-utero Mercury Exposure via Maternal Fish Consumption.* Mercury is a highly toxic pollutant that presents serious health risks to adults and children, even in very small doses. Health effects can include damage to the brain, kidneys, heart, and especially nervous system. These impacts are particularly harmful for children, who can experience profound and permanent developmental and neurological delays as a result of exposure in-utero. EPA estimated the IQ-related benefits associated with reduced in-utero mercury exposure from maternal fish consumption in exposed populations. EPA used data on the populations living within 100 miles of affected waterbodies, state-specific average fishing rates, presence of fish consumption advisories, the availability of substitute fishing locations, average household size, the number of women of childbearing age, and state-specific birth rates to estimate the number of births in the exposed population. Based on a dose-response function developed by Axelrad et al. (2007), EPA assigned a 0.18 point IQ loss for each 1 ppm increase in maternal hair mercury. To translate the daily mercury ingestion rate by women of childbearing age in the exposed populations to hair mercury concentrations, EPA used a conversion rate derived by Swartout and Rice (2000). Including decreased lifetime earnings and avoided education costs, EPA assumed that the value of an IQ point is between $1,156 and $13,651 over the life of each individual.

Table XIV–2 summarizes monetized human health benefits associated with five of the eight regulatory options considered in this proposed rule using 3 percent and 7 percent discount rates. As mentioned above, EPA did not monetize the human health benefits associated with Options 3a, 3b and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

TABLE XIV–2—ANNUALIZED HUMAN HEALTH BENEFITS

[million 2010$] [c]

Human health benefit category	Option 1	Option 2	Option 3	Option 4	Option 5
3% Discount Rate					
Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption.	<$0.1	<$0.1	$0.1	$0.2	$0.2
Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption [a].	$0.1 ($0.1 to $0.1)	$0.1 ($0.1 to $0.1)	$2.7 ($2.2 to $3.2)	$6.7 ($5.6 to $7.9)	$6.7 ($6.5 to $7.9)

TABLE XIV–2—ANNUALIZED HUMAN HEALTH BENEFITS—Continued

[million 2010$] [c]

Human health benefit category	Option 1	Option 2	Option 3	Option 4	Option 5
Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption.	<$0.1 (<$0.1 to <$0.1).	<$0.1 (<$0.1 to <$0.1).	<$0.1 (<$0.1 to <$0.1).	$0.1 ($0.1 to $0.1)	$0.1 ($0.1 to $0.1)
Benefits of Reduced In-utero Mercury Exposure via Maternal Fish Consumption [a].	$3.8 ($3.2 to $4.5)	$3.9 ($3.2 to $4.6)	$5.0 ($4.1 to $5.8)	$10.2 ($8.4 to $12.1)	$10.2 ($8.4 to $12/1)
Total Human Health Benefits [b].	$3.9 ($3.21 to $4.59)	$4.0 ($3.28 to $4.69)	$7.7 ($6.4 to $9.11) ..	$17. ($14.2 to $20.2)	$17. ($14.2 to $20.2)
7% Discount Rate					
Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption.	<$0.1	<$0.1	$0.1	$0.1	$0.1
Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption [a].	<$0.1 (<$0.1 to <$0.1).	<$0.1 (<$0.1 to <$0.1).	$0.2 ($0.2 to $0.3)	$0.6 ($0.4 to $0.8)	$0.6 ($0.4 to $0.8)
Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption.	<$0.1 (<$0.1 to <$0.1).	<$0.1 (<$0.1 to <$0.1).	<$0.1 (<$0.1 to <$0.1).	<$0.1 (<$0.1 to <$0.1).	<$0.1 (<$0.1 to <$0.1)
Benefits of Reduced In-utero Mercury Exposure via Maternal Fish Consumption [a].	$0.3 ($0.2 to $0.5)	$0.4 ($0.2 to $0.5)	$0.4 ($0.3 to $0.6)	$0.9 ($0.6 to $1.2)	$0.9 ($0.6 to $1.2)
Total Human Health Benefits [b].	$0.4 ($0.2 to $0.5)	$0.4 ($0.2 to $0.5)	$0.7 ($0.5 to $1.0)	$1.6 ($1.1 to $2.1)	$1.6 ($1.1 to $2.1)

[a] Low end assumes that the loss of one IQ point results in the loss of 1.76% of lifetime earnings (following Schwartz, 1994); high end assumes that the loss of one IQ point results in the loss of 2.38% of lifetime earnings (following Salkever, 1995).
[b] Totals may not add up due to independent rounding.
[c] EPA did not estimate the benefits of Options 3a, 3b and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

b. Reduced Exceedances of Health-Based AWQC

EPA expects that additional health benefits will arise from reduced discharges of steam electric pollutants; however, monetary valuation of these other health benefits is not currently possible due to lack of data on a dose-response relationship between pollutant ingestion rate and potential adverse health effects. To provide an additional measure of the potential health benefits of the proposed ELGs, EPA estimated the effect of steam electric plant discharges on the occurrence of pollutant concentrations in affected waterways that exceed human health-based ambient water quality criteria (AWQCs).[84] Pollutant concentrations in excess of these values indicate potential risks to human health. This analysis and its findings are not additive to the preceding analyses of change in cancer or lead-related health risks but are another way of quantitatively characterizing possible benefit categories.

EPA estimates that in-stream concentrations of steam electric pollutants (i.e., arsenic, cadmium, chromium, copper, lead, mercury, nickel, selenium, thallium, and zinc) exceed human health criteria for consumption of water and organisms for at least one pollutant in 146 receiving reaches nationwide in the baseline. Depending on the regulatory option, EPA expects that the proposed rule would eliminate the occurrence of concentrations in excess of human health criteria for consumption of water and organisms for 0 to 98 of the contaminated reaches, and reduce the number of exceedances in 9 to 27 reaches. Option 3 is estimated to

[84] Including AWQCs for the protection of human health through consumption of organisms and water.

eliminate exceedances in 27 receiving reaches, out of the 146 receiving reaches with exceedances in the baseline, while Option 4 is estimated to reduce exceedances in 98 reaches and eliminate exceedances altogether in 24 of those reaches. EPA did not quantitatively analyze the change in exceedances for Options 3a, 3b and 4a. However, EPA expects the effects of Option 4a to be between those of Options 3 and 4 (i.e., reduce or eliminate exceedances in between 27 and 98 receiving reaches).

2. Improved Ecological Conditions and Recreational Use Benefits From Surface Water Quality Improvements

EPA expects the proposed ELGs to provide ecological benefits by improving ecosystems (aquatic and terrestrial) affected by the electric power industry's effluent discharges. Benefits associated with changes in aquatic life include restoration of sensitive species, recovery of diseased species, changes in taste-and odor-producing algae, changes in dissolved oxygen (DO), increased assimilative capacity of affected waterways, and improved related recreational activities. Activities such as fishing, swimming, wildlife viewing, camping, waterfowl hunting, and boating may be enhanced when risks to aquatic life and perceivable water quality effects associated with pollutants are reduced. The magnitude of these benefits depends on the regulatory option.

EPA was able to monetize several categories of ecological benefits associated with this proposed rule, including recreational use and nonuse (i.e., existence, bequest, and altruistic) benefits from improvements in the health of aquatic environments, and nonuse benefits from increased populations of threatened and endangered species. As shown in Table XIV–1, the Agency quantified and monetized two main benefit subcategories, discussed below: (1) Benefits from improvements in surface water quality, and (2) benefits from improved protection of threatened and endangered (T&E) species.

a. Improvements in Surface Water Quality

EPA expects these proposed ELGs to improve aquatic species habitats by reducing concentrations of toxic contaminants such as arsenic, cadmium, chromium, lead, mercury, nickel, selenium, and zinc in water. The rule is also expected to reduce nitrogen and phosphorus concentrations. These improvements would be expected to enhance the quality and value of water-based recreation. For example, some of the streams that were not usable for recreation under the baseline discharge conditions may become usable following implementation of the rule, thereby expanding options for recreational users. Streams that have been used for recreation under the baseline conditions can become more attractive for users by making recreational trips even more enjoyable. Individuals may also take trips more frequently if they enjoy their recreational activities more. These proposed ELGs are also expected to generate nonuse benefits from bequest, altruism, and existence motivations. Individuals may value the knowledge that water quality is being maintained, ecosystems are being protected, and species populations are healthy, independently of their use.

To calculate baseline and post-compliance water quality, EPA utilized a water quality index (WQI) that translates water quality measurements, gathered for multiple parameters that are indicative of various aspects of water quality, into a single numerical indicator that reflects achievement of quality consistent with certain uses. The WQI provides the link between specific pollutant levels, as reflected in individual parameters, and the presence of aquatic species and suitability for particular recreational uses. Traditionally, WQIs are based on conventional pollutants (e.g., TSS, BOD, and fecal coliform) and nutrients (nitrogen and phosphorus). To account for water quality improvements resulting from reductions in toxic pollutants, EPA expanded the set of WQI parameters to include metals. The metals sub-index follows an approach developed by the Canadian Council of Ministers of the Environment (CCME) and uses the number of AWQC exceedances for a given waterbody in the baseline and/or under a given regulatory option.[85] EPA assigned all parameters in the index an equal weight of 1/7th following other studies that use equal weights for all index parameters (Cude 2001, CCME 2001, and Carruthers and Wazniak 2003).

EPA calculated baseline and post compliance WQI values for reaches affected by steam electric plant discharges. Baseline and post compliance water quality data were taken from several sources including USGS's SPARROW model, EPA's Risk-Screening Environmental Indicators (RSEI) model, EPA's STORET data warehouse, and estimated in-stream concentrations of steam electric pollutants. These sources provide water quality for stream networks defined according to the medium-resolution NHD or RF1. EPA conducted the benefits analysis at the level of RF1 reaches and mapped NHD data to the appropriate RF1, as needed, depending on the data source. EPA estimates that 3,945 reach miles would improve under Option 1 for existing sources, 12,683 miles under Option 2, 15,682 miles under Option 3, 22,447 reach miles under Option 4, and 22,441 reach miles under Option 5. EPA did not estimate the number of reach miles that would improve under Option 4a but expects improvements to be between those of Options 3 and 4 (i.e., between 15,682 and 22,447 reach miles).

EPA estimated monetized benefit values using a meta-regression of surface water valuation studies originally developed for the Effluent Guidelines and Standards for the Construction and Development Point Source Category (U.S. EPA, 2009). EPA used two benefit functions for each reach; one for households within a 100-mile radius of the reach that may have user values and one for nonuser households, located in the same state as the reach, but outside the 100-mile radius. Each benefit function was estimated for the years between 2014 and 2040, although benefits start accruing in 2017 when certain plants would be expected to start installing control technologies under this proposal (i.e., no benefits are assumed for 2014–2016). EPA estimated total benefits for each group—users and nonusers—as follows:

- The Agency first estimated annual household WTP values for a given reach and year using the meta-analysis regression. WTP values are a function of (1) reach-specific baseline and change in water quality values in a given year and (2) median household income values estimated for a given state or buffer zone in that year. For this analysis, two benefit functions were used for each reach in a given year; one for households that may have user values (households located within 100 miles of the reach) and one for nonuser households (households located with the same state as the reach, but outside the 100-mile buffer).
- To estimate total WTP values, the Agency multiplied annual household WTP values by the percent of total reach miles within the state or buffer and the total number of households within the state or buffer for a given year.
- EPA then discounted total WTP values to 2014, the expected

[85] There may be between 0 and 8 exceedances per waterbody (freshwater chronic AWQC values are available for arsenic, cadmium, chromium, lead, mercury, nickel, selenium, and zinc).

promulgation year of the rule, and annualized them using a 3 and 7 percent discount rate.

A challenge for meta-analysis is developing a framework that both controls for differences in studies and can be used for meaningfully predicting benefits associated with regulatory options. In earlier benefits estimation for effluent guidelines, EPA often relied on the Carson and Mitchell (1993) water quality values. These values come from a survey that was one of the first major stated preference efforts, fielded in the early 1980s. The study reported values for all of the nation's waters, using the same WQI that is used in the meta-analysis. When EPA used the Carson and Mitchell values, the Agency was able to tailor its benefits estimates to its regulations in two important dimensions: the level of water quality improvement, and the percent of the nation's waters being improved. EPA is basing this benefits analysis on the meta-analysis because stated preference methodology and practices have advanced considerably since the Carson and Mitchell study (although methodological issues continue to be debated in the stated preference literature), more studies have been conducted, and changes in individuals' preferences and income may well result in changing water quality values.

A trade-off, however, in using the meta-analysis is the difficulty in representing the percent of the nation's waters that are being improved, in addition to combining the results of studies encompassing a variety of water quality improvements, geographic scales, and resource characteristics that has led to both expected results and results that are counterintuitive. To provide perspective on these different approaches to measure water quality improvement benefits, EPA is also reporting the water quality values obtained by applying the Carson and Mitchell values. In 2011 dollars, using a 3 percent discount rate, these values are: for Option 1, $0.5 million; for Option 2, $2.9 million; for Option 3, $4.5 million; for Option 4, $12.9 million; and for Option 5, $12.7 million. EPA requests comment on its reliance on the meta-analysis values rather than the Carson and Mitchell values (or some other values) as the basis for estimating water quality benefits of the proposed rule. Commenters should address methodological strengths and weaknesses of any suggested approach, and explain the basis for their recommendation.

b. Benefits to Threatened and Endangered (T&E) Species

To assess the potential for impacts on threatened and endangered (T&E) species (both aquatic and terrestrial), EPA constructed a database of waterbodies currently exceeding wildlife-based AWQC but expected to have no wildlife AWQC exceedances as a result of the proposed ELGs. EPA then assessed the overlap between this geographic database and the known locations of approximately 530 T&E species. Once species overlapping waterbodies of interest were identified, EPA examined their life history traits to categorize species by the potential for population impacts likely to occur as a result of changes in water quality. T&E species with high probability of life-history effects were further screened to identify those species for which water quality was identified as a factor for listing under the Endangered Species Act (ESA) or as a limiting factor within species recovery plans. Because of this analysis, EPA identified seven fish species and one dragonfly species that may experience changes in population growth rates as a result of the proposed ELGs. EPA did not identify data sufficient to explicitly model the effects of changes in water quality on population growth rates for these species. Therefore, to estimate total population increases resulting from the proposed ELGs, EPA assumed minimal increases in population size of 0.5, 1, or 1.5 percent. To estimate monetary benefits to T&E species, EPA weighted these population growth estimates by the percent of reaches used by T&E species that are expected to meet wildlife-based AWQC because of the proposed ELGs.

The T&E species expected to benefit from the rule include two species of sturgeon and five species of small minnows. All of these species have nonuse values including existence, bequest, altruistic, and ecological service values apart from human uses or motives.

To estimate the potential economic values of increased T&E species populations affected by the proposed ELGs, EPA used a benefit function transfer approach based on a meta-analysis of 31 stated preference studies eliciting WTP for these changes (Richardson and Loomis 2009). This meta-analysis is based on studies conducted in the United States that valued threatened, rare, or endangered fish, bird, reptile, or mammal species. Because the underlying meta-data does not include insect valuation studies, EPA was unable to monetize any benefits for potential population increases of Hine's Emerald Dragonfly due to the proposed rule. For each state containing T&E species estimated to show population growth because of the proposed ELGs, EPA calculated benefits using the weighted population growth assumptions under each analytic scenario (regulatory option and population increase assumption). For states with more than one T&E species estimated to see population growth, EPA only monetized the value for the species projected to see the greatest proportional population increase. Because population growth was calculated at the state level, EPA was unable to calculate benefits based on when each steam electric plant is assumed to install control technologies to comply with the proposed ELGs. EPA therefore assumed that benefits begin accruing in 2019 for all states because this is the midpoint of the compliance period used in other cost and benefit analyses and thus provides a reasonable assumption.

There may be some overlap between WTP estimates for T&E species and the WTP estimates for improvements in water quality; however, the magnitude of this overlap is likely to be minimal because none of the studies in EPA's meta-analysis of WTP for water quality improvements specifically mentioned or otherwise prompted respondents to include benefits to T&E species populations.

Table XIV–3 summarizes the results of EPA's analysis of benefits from improved ecological conditions and recreational uses for five of the eight regulatory options. EPA did not estimate the benefits of Options 3a, 3b and 4a. As for the other benefit categories, however, the Agency expects the benefits of Option 4a to be between those of Options 3 and 4 (i.e., between $59.9 million and $116.1 million annually, at 3 percent discount rate).

TABLE XIV–3—ANNUALIZED ECOLOGICAL CONDITIONS AND RECREATIONAL USES BENEFITS
[Million 2010$] [e]

Benefit category	Option 1	Option 2	Option 3	Option 4	Option 5
3% Discount Rate					
Improved Surface Water Quality [a]	$8.3 ($2.0 to $22.4)	$38.0 ($7.1 to $107.1).	$49.9 ($10.2 to $137.6).	$82.8 ($19.6 to $215.8).	$81.9 ($19.3 to $214.1)
Benefits to E&T Species [b]	$7.0 ($3.9 to $10.0)	$7.0 ($3.9 to $10.0)	$10.0 ($5.5 to $14.2)	$33.3 ($18.2 to $47.3).	$33.3 ($18.2 to $47.3)
Total Ecological and Recreational Uses Benefits [d]	$15.3 ($5.8 to $32.4)	$45.0 ($11.0 to $117.7).	$59.9 ($15.7 to $151.8).	$116.1 ($37.8 to $263.1).	$115.2 ($37.5 to $261.4)
7% Discount Rate					
Improved Surface Water Quality [a]	$6.9 ($1.6 to $18.7)	$31.7 ($6.0 to $48.3)	$41.7 ($8.5 to $115.0).	$69.2 ($16.4 to $180.3).	$68.5 ($16.1 to $178.9)
Benefits to E&T Species [b]	$5.9 ($3.2 to $8.4)	$5.9 ($3.2 to $8.4)	$8.4 ($4.6 to $11.9)	$27.8 ($15.2 to $39.5).	$27.8 ($15.2 to $39.5)
Total Ecological and Recreational Uses Benefits [d]	$12.8 ($4.8 to $27.0)	$37.6 ($9.1 to $56.6)	$50.1 ($13.1 to $126.9).	$97.0 ($31.6 to $219.8).	$96.2 ($31.3 to $218.4)

[a] Values represent partial benefits only for reaches that receive direct discharges from steam electric plants. Range in parenthesis represents the 5th and 95th percentile of the WTP distribution.
[b] Range in parenthesis provides the low and high bound estimates.
[c] Range in parenthesis provides the 5th and 95th percentile of the WTP distribution incorporating minimum and maximum flow reduction assumptions.
[d] Totals may not add up due to independent rounding.
[e] EPA did not estimate the benefits of Options 3a, 3b and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

3. Groundwater Quality Benefits From Reduced Groundwater Contamination

EPA expects that some of the regulatory options will eliminate the future leaching of steam electric pollutants from steam electric impoundments to groundwater aquifers. The Agency monetized the associated benefits to households using private drinking wells in the vicinity of steam electric plants based on a benefits transfer from groundwater valuation studies. Specifically, EPA used existing groundwater valuation studies to derive household WTP estimates for two categorical improvements in groundwater quality: (1) ''greatly improved'' and (2) ''improved.''

EPA identified the exposed population as the number of households using private drinking water wells in the vicinity of steam electric impoundments. EPA then modeled pollutant concentrations in the affected aquifers and determined which aquifers exceed maximum contaminant levels (MCLs) for steam electric pollutants under the baseline. EPA assumed that if a plant ceases to use impoundments to handle combustion waste because of the proposed ELGs, these aquifers would improve, with an average household WTP of $450. For impoundments that continue to receive combustion wastes but in smaller amounts, EPA assumed that the plant-specific benefits would be proportional to the reduction in wastewater flows going to the impoundment, and scaled the benefits accordingly.

Table XIV–4 summarizes the results of EPA's analysis of the groundwater benefits. As for other benefit categories, EPA did not analyze the benefits of Options 3a, 3b and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4 (i.e., $1.6 million to $6.5 million annually, at 3 percent discount rate).

TABLE XIV–4—ANNUALIZED GROUNDWATER QUALITY BENEFITS
[Million 2010$]

Discount rate	Option 1	Option 2	Option 3	Option 4	Option 5
3% Discount Rate	$0.7	$0.7	$1.6	$6.5	$6.5
7% Discount Rate	0.6	0.6	1.4	5.5	5.5

4. Market and Productivity Benefits (Benefits From Reduced Impoundment Failures)

Operational changes prompted by compliance with the proposed ELGs may cause some plant owners to reduce their reliance on impoundments to handle their waste. EPA expects these changes to reduce future impacts from impoundment failures.

To assess the benefits associated with changes in impoundment use, EPA estimated the costs associated with expected failures for baseline conditions (assuming no change in operations) and for projected reductions in the amount of CCR waste managed by impoundments for five of the eight regulatory options (Options 1, 2, 3, 4, and 5). EPA performed the calculations for each of the 1,070 impoundments identified at steam electric plants, and for each year between 2014 and 2040. EPA then calculated benefits as the difference between expected failure costs for a regulatory option and expected failure costs under baseline conditions.

To estimate the number of structural failure events that may be avoided as a result of the proposed ELGs, EPA used data on historical impoundment failures collected by EPA's Office of Resource Conservation and Recovery (ORCR) for its Regulatory Impact Analysis for EPA's Proposed Regulation of Coal Combustion Residues Generated by the Electric Utility Industry (Proposed CCR Rule; U.S. EPA 2010). Based on historical data, EPA estimated an average failure rate of 0.58 percent per impoundment per year and used this average failure rate to calculate the expected number of failure events in the baseline and under each of the regulatory options.[86] EPA also used data on historical failure events to develop average cleanup, natural resource damages,[87] and litigation costs [88] per event. As detailed in Chapter 7 of the BCA, EPA used average total costs of $0.06 per gallon of impoundment capacity to estimate the expected costs of an impoundment failure.[89] EPA did not calculate benefits for years 2014 through 2018 because EPA conducted surface impoundment integrity site assessments in 2009 through 2012 and expects the assessments and the recommended ''action plan'' improvements to impoundment structures will prevent all failures for the first five years after improvement are completed (i.e., 2014 through 2018).

Table XIV–5 presents the analysis results. Depending on the regulatory option, annual benefits range from $62.1 million to $295.1 million (at 3 percent discount rate), with Option 3 having expected benefits of $114.8 million per year. EPA did not estimate the benefits of Options 3a, 3b and 4a; the Agency expects the benefits of Option 4a to be between those of Options 3 and 4 (i.e., $114.8 million to $295.1 million, at 3 percent discount rate). Note that these benefits do not include the effects of BMPs that may reduce the probability of failures and therefore would be expected to increase the benefits of the proposed ELGs. EPA will continue to seek ways to quantify and monetize BMP-related benefits in analyses for the final rule, should EPA ultimately include such BMPs as part of the final ELGs.

TABLE XIV–5—ANNUALIZED BENEFITS OF REDUCED IMPOUNDMENT FAILURES

[Million 2010$]

Discount rate	Option 1	Option 2	Option 3	Option 4	Option 5
3% Discount Rate	$62.1	$62.1	$114.8	$295.1	$295.1
7% Discount Rate	52.2	52.2	95.9	245.9	245.9

5. Air-Related Benefits (Reduced Mortality and Avoided Climate Change Impacts)

The proposed ELGs are expected to affect air pollution through three main mechanisms: 1) 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; 2) additional transportation-related emissions due to the increased trucking of CCR waste to landfills; and 3) the change in the profile of electricity generation due to the relatively higher cost to generate electricity at plants incurring compliance costs for the proposed ELGs. Changes in the profile of generation can result in lower or higher air pollutant emissions because of variability in emission factors for different types of electricity generating units. For this analysis, the changes in air emissions are based on the change in dispatch of generation units projected by IPM as a result of overlaying the costs of the proposed ELGs onto steam electric units production costs.

In this analysis, EPA estimated the human health and other benefits resulting from net changes in air emissions of three pollutants: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and carbon dioxide (CO_2). NO_X and SO_X are known precursors to fine particles ($PM_{2.5}$), a criteria air pollutant that has been associated with a variety of adverse health effects—most notably, premature mortality. CO_2 is an important greenhouse gas that is linked to a wide range of climate change effects.

EPA used average benefit-per-ton (BPT) estimates to value benefits of changes in NO_X and SO_2 emissions, and social cost of carbon (SCC) estimates to value benefits of changes in CO_2 emissions. Because the analysis relies in part on estimates of air emissions obtained from IPM, EPA estimated air-related benefits for Options 3 and 4 only, as these are the two options analyzed in IPM. Table XIV–6

[86] EPA also estimated benefits using a best-fit regression equation developed based on the historical data that relates the probability of impoundment failure to impoundment capacity. For details, see Appendix G of the BCA.

[87] Natural resource damages do not include cleanup costs (or legal costs) but include only the resource restoration and compensation values. For example, in one case, Israel (2006) found that ''In total, the State's claim was $764 million, $342 million of which was restoration cost damages, $410 million of which was compensable value damages, and $12 million of which was assessment and legal costs.'' For this case, EPA used the sum of $342 million and $410 million (excluded legal costs) as the value of natural resource damages.

[88] For this analysis, litigation costs include the costs associated with negotiating NRD, determining responsibility among potentially responsible parties, and litigating details regarding settlements and remediation. These activities involve services, whether performed by the complying entity or other parties that EPA expects would be required in the absence of this regulation in the event of an impoundment failure. Note that the litigation costs do not include fines, cleanup costs, damages, or other costs that constitute transfers or are already accounted for in the other categories analyzed separately.

[89] This estimate assumes that each failure results in a spilled volume equal to 6.45 percent of the impoundment capacity, based on the average ratio of spill volume to impoundment capacity for 15 releases for which ORCR obtained both spill volume and capacity data.

summarizes the annualized benefits associated with changes in air pollutant emissions. Chapter 8 in the BCA report provides the details of this analysis.

TABLE XIV–6—ANNUALIZED BENEFITS OF CHANGES IN NO_X, SO_2, AND CO_2 AIR EMISSIONS

[Million 2010$] [c]

Discount rate	Option 3	Option 4
3% Discount Rate (for NO_X, SO_2, and CO_2-related benefits)	$127.6	$170.5
7% Discount Rate (for NO_X, SO_2, and CO_2-related benefits) [a b]	82.3	74.6

[a] Because SCC values are not available for the 7 percent discount rate, EPA used the SCC based on a 5 percent discount rate to estimate values presented for the 7 percent discount rate. EPA uses 5 percent to discount CO_2-related benefits and 7 percent to discount benefits from changes in NO_X and SO_2 emissions.

[b] Air benefits for Option 4 at the 7 percent discount rate are lower than benefits estimated for Option 3 due to (1) smaller SO_2 emissions reductions projected by IPM for Option 4 than Option 3 in early years and (2) differences in source- and discount-specific BPT and SCC values.

[c] EPA did not estimate the benefits of Options 3a, 1, 2, 3b, 4a and 5. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

6. Benefits From Reduced Water Withdrawals (Increased Availability of Groundwater Resources)

Steam electric plants use water for handling solid waste (e.g., fly ash, bottom ash) and for operating wet FGD scrubbers. By eliminating or reducing water used in sluicing operations or prompting the recycling of water in FGD wastewater treatment systems, the proposed ELGs are expected to reduce water withdrawals from surface waterbodies and reduce demand on aquifers, in the case of plants that rely on groundwater sources.

EPA estimated the benefits of reduced groundwater withdrawals based on avoided costs of groundwater supply. For each affected facility and regulatory option, EPA multiplied the reduction in groundwater withdrawal (in gallons per year) by water costs ranging between $150 and $500 per acre-foot.

Table XIV–7 summarizes the annualized benefits associated with changes in water use by steam electric plants for five of the eight options. Chapter 9 in the BCA report provides the details of this analysis. While EPA did not estimate benefits of Options 3a, 3b and 4a, the Agency expects the benefits of Option 4a to be between those of Options 3 and 4.

TABLE XIV–7—ANNUALIZED MONETIZED BENEFITS OF REDUCED WATER WITHDRAWALS BY STEAM ELECTRIC PLANTS

[Million 2010$] [a]

Benefit category	Option 1	Option 2	Option 3	Option 4	Option 5
3% Discount Rate					
Avoided groundwater withdrawals	$0.0	$0.0	<$0.1	$0.1	$0.1
7% Discount Rate					
Avoided groundwater withdrawals	0.0	0.0	<0.1	0.1	0.1

[a] EPA did not estimate the benefits of Options 3a and 4a. EPA expects the benefits of Option 4a to be between those of Options 3 and 4.

C. Total Monetized Benefits

Using the analysis approach described above, EPA estimates annual total benefits for the six monetized categories at approximately $82 million to $605.5 million (at 3 percent discount rate), depending on the option and based on EPA's analysis of five of the eight regulatory options (Table XIV–8). BAT and PSES option 3 has annual total benefits estimated at $311.7 million (at 3 percent discount rate). While EPA did not quantify the benefits of the other three preferred BAT and PSES Options (Option 3a, Option 3b and Option 4a), EPA expects the annual total benefits of Option 4a to be between those of Option 3 and 4 (i.e., $311.7 million to $605.5 million at 3 percent discount rate).

The monetized benefits of this proposed rule do not account for all benefits because, as described above, EPA is unable to monetize some categories. Examples of benefit categories not reflected in these estimates include non-cancer health benefits (other than IQ benefits from reduced childhood exposure to lead and in-utero exposure to mercury) and reduced cost of drinking water treatment for the pollutants with drinking water criteria. In addition, EPA's analysis of human health benefits associated with water quality improvements includes only partial benefits for directly receiving reaches.

EPA will continue to seek ways to monetize benefit categories not monetized in this proposal in order to provide a more accurate representation of benefits of the proposed rule.

TABLE XIV–8—SUMMARY OF TOTAL ANNUALIZED MONETIZED BENEFITS OF PROPOSED ELGS

[Million 2010$] [f]

Benefit category	Option 1	Option 2	Option 3	Option 4	Option 5
3 Percent Discount Rate					
Human Health Benefits [a c]	$3.9	$4.0	$7.7	$17.2	$17.2

TABLE XIV–8—SUMMARY OF TOTAL ANNUALIZED MONETIZED BENEFITS OF PROPOSED ELGS—Continued

[Million 2010$] [f]

Benefit category	Option 1	Option 2	Option 3	Option 4	Option 5
Improved Ecological Conditions and Recreational Uses [a b]	15.3	45.0	59.9	116.1	115.2
Groundwater Quality Benefits	0.7	0.7	1.6	6.5	6.5
Market and Productivity Benefits	62.1	62.1	114.8	295.1	295.1
Air-Related Benefits [d]	NE	NE	127.6	170.5	NE
Reduced Water Withdrawals	0.0	0.0	≤0.1	0.1	0.1
Total benefits, Excluding Air-Related Benefits	82.0	111.7	184.1	435.0	434.1
Total Benefits (Including Air-related Benefits) [a]	....	....	311.7	605.5	....
7 Percent Discount Rate					
Human Health Benefits [a c]	0.4	0.4	0.7	1.6	1.6
Improved Ecological Conditions and Recreational Uses [a b]	12.8	37.6	50.1	97.0	96.2
Groundwater Quality Benefits	0.6	0.6	1.4	5.5	5.5
Market and Productivity Benefits	52.2	52.2	95.9	245.9	245.9
Air-Related Benefits [d e]	NE	NE	82.3	74.5	NE
Reduced Water Withdrawals	0.0	0.0	0.0	0.1	0.1
Total benefits, Excluding Air-Related Benefits	65.9	90.7	148.1	350.2	349.4
Total Benefits (Including Air-related Benefits) [a]	....	....	230.4	424.8	....

[a] Values represent mean benefit estimates. Totals may not add up due to independent rounding. Option 5 results in slightly lower benefits because, under Option 4, EPA assumes that plants with both leachate and FGD waste streams implement chemical precipitation and biological treatment for the combined streams. Under Option 5, EPA assumes that plants treat the two streams separately: FGD wastewater by evaporation and leachate using chemical precipitation (which removes less pollutant load than biological treatment).

[b] There may be some overlap between the willingness-to-pay (WTP) for surface water quality improvements and WTP for benefits to threatened and endangered species.

[c] Values represent partial human health benefits only for reaches that receive direct discharges from steam electric plants.

[d] EPA estimated air-related benefits for Options 3 and 4 only because these benefits were estimated as part of the Agency's analysis using IPM. Total benefits for Options 1, 2, and 5 are therefore understated. Air benefits for Option 4 at the 7 percent discount rate are lower than benefits estimated for Option 3 due to (1) smaller SO_2 emissions reductions projected by IPM for Option 4 than Option 3 in early years and (2) differences in source- and discount-specific BPT and SCC values.

[e] Because SCC values are not available for the 7 percent discount rate, EPA used the SCC based on a 5 percent discount rate and discounted CO_2-related benefits using a 5 percent discount rate, as compared to benefits in other categories, which are discounted using the 7 percent discount rate.

[f] EPA did not estimate benefits for Options 3a, 3b and 4a, but expects the benefits of Option 4a to be between those of Options 3 and 4.

Further, as noted earlier in this section, EPA calculated benefits for some of the options considered for this proposal. Benefits for these options, however, provide information relevant to understanding the potential magnitude of benefits under all proposed options, including Options 3a, 3b, and 4a. As explained earlier in this preamble, the facilities affected by Option 3a are a subset of Option 3 facilities; Option 3 benefit estimates therefore provide an upper bound estimate of benefits anticipated under Options 3a and 3b. In a similar way, EPA expects Option 4 to provide an upper bound estimate of benefits anticipated under Option 4a. As an illustrative analysis, EPA inferred the potential benefits associated with Options 3a and 3b by subtracting the benefits for Option 2 (scaled up to include a rough estimate of air emissions benefits) from the benefits for Option 3, because Option 3 includes a combination of the wastestreams and control technologies in Options 3a and 2. EPA inferred the potential benefits associated with Option 3b based on the pollutant loading reductions (pounds) projected for Option 3b relative to pollutant loading reductions projected for Option 2 (plus the fly ash dry handling benefits of Option 3a) because Option 3b includes both fly ash requirements and the Option 2 FGD wastewater treatment requirements for a subset of facilities. Specifically, EPA inferred the benefits of Options 3a and 3b by multiplying the FGD benefits estimated for Option 2 by the ratio of pollutant loads removed by 3b over Option 2, and then adding in the fly ash benefits that are also included in Option 3b. Similarly, EPA inferred the potential benefits associated with Option 4a based on the bottom ash pollutant loading reductions projected for this option, relative to bottom ash pollutant loading reductions projected for Option 4, plus the benefits of Option 3, because Option 4a includes all of the requirements of option 3 plus the bottom ash requirements of Option 4 for a subset of facilities.

Table XIV–9 summarizes total annualized benefits estimated (or inferred using the calculations described above) for the eight options discussed in this proposal. Note that there is significant uncertainty in values inferred because the methodology used does not account for differences in the pollutants, receiving waterbodies, and exposed populations between the options.

TABLE XIV–9—TOTAL MONETIZED BENEFITS FOR THE PROPOSED RULE

[Millions; 2010]

Regulatory option	Method	Total monetized benefits 3%	Total monetized benefits 7%
Option 1	Estimate [a]	$82.0	$65.9
Option 3a	Inference [b]	139.4	104.8
Option 2	Estimate [a]	111.7	90.7
Option 3b	Inference [b]	205.5	153.0
Option 3	Estimate	311.7	230.4
Option 4a	Inference [b]	482.5	343.4
Option 4	Estimate	605.5	424.8
Option 5	Estimate [a]	434.1	349.4

[a] Total benefits for Options 1, 2, and 5 do not include air-related benefits (see Table XIV–8).
[b] EPA did not estimate benefits for Options 3a, 3b and 4a. EPA inferred benefits for Options 3a, 3b, and 4a for illustrative purposes using elements of the more rigorous analysis done to estimate benefits for Options 3 and 4.

D. Children's Environmental Health

As described in Section XIV.B.1, EPA assessed whether these proposed ELGs will benefit children by reducing health risk from exposure to steam electric pollutants from consumption of contaminated fish tissue and improving recreational opportunities. The Agency was able to quantify two categories of benefits specific to children: (1) Avoided neurological damage to pre-school age children from reduced exposure to lead and (2) avoided neurological damages from in-utero exposure to mercury.

This analysis considered several measures of children's health benefits associated with lead exposure for children up to age six. Avoided neurological and cognitive damages were expressed as changes in three metrics: (1) Overall IQ levels; (2) the incidence of low IQ scores (<70); and (3) the incidence of blood-lead levels above 20 mg/dL. EPA's methodology for assessing lead-related benefits to children is presented in Chapter 3 of the BCA report. EPA analysis shows that benefits to children from reduced lead discharges range from $0.1 million to $6.8 million (at 3 percent discount), depending on the regulatory option; annual benefits for Option 3 are estimated at $2.7 million (at 3 percent discount rate). EPA did not quantify the benefits to children of Options 3a, 3b and 4a; however, the Agency expects the annual benefits of Option 4a to be between those of Options 3 and 4 (i.e., between $2.7 million and $6.8 million).

Children over the age of seven are also likely to benefit from reduced exposure to lead and the resultant neurological and cognitive damages, even though EPA did not quantify these benefits in its analysis of the proposed ELGs. Giedd et al. (1999) studied brain development among 10- to 18-year-old children and found substantial growth in brain development, mainly during early teenage years. This research suggests that older children may be hypersensitive to lead exposure, as are children aged 0 to 7.

Additional benefits to children from reduced exposure to lead not quantified in this analysis may include prevention of the following adverse health effects: slowed or delayed growth, delinquent and anti-social behavior, metabolic effects, impaired heme synthesis, anemia, impaired hearing, and cancer.

EPA also estimated the IQ-related benefits associated with reduced in-utero mercury exposure from maternal fish consumption in exposed populations. Chapter 3 of the BCA report presents EPA's methodology for assessing mercury-related benefits to children. Among approximately 1,932 babies born per year who are potentially exposed to discharges of mercury from steam electric plants, the proposed ELGs reduce total IQ point losses over the period of 2017 through 2040 by about 9,000 to 24,000 points, depending on the regulatory option. The monetary benefits associated with the avoided IQ point losses range from $3.8 million and $10.2 million per year (mean estimate, at 3 percent discount rate), across the five options EPA analyzed. Option 3 is estimated to avoid the loss of about 12,000 IQ points in exposed infants over the 24-year period. The benefits associated with these avoided IQ point losses are estimated at $5.0 million per year. EPA did not quantify the benefits to children of Options 3a, 3b and 4a; for Option 4a, however, EPA expects the annual benefits to be between those of Options 3 and 4 (i.e., $5.0 million to $10.2 million).

XV. Non-Water Quality Environmental Impacts

The elimination or reduction of one form of pollution may create or aggravate other environmental problems. Therefore, Sections 304(b) and 306 of the Act require EPA to consider non-water quality environmental impacts (including energy impacts) associated with ELGs. Accordingly, EPA has considered the potential impact of the regulatory options on air emissions, solid waste generation, and energy consumption.

A. 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 facilities that it projected would incur costs to comply with these 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 facility. 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 facility-specific estimate to calculate the net increase in energy requirements for the regulatory options discussed in this 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 based on the horsepower rating of the pumps and other equipment. To determine 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. See DCN SE01957 (*Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category*) for more information on the specific calculations used to estimate changes in energy use. Table XV–1 shows the net change in annual electrical energy usage associated with the proposed regulation.

Energy usage also includes the fuel consumption associated with transportation. EPA estimated the need for increased transportation of solid waste and combustion residuals (e.g., ash) at steam electric power plants to on-site or off-site landfills using open dump trucks. 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 the energy usage associated with the dust suppression water trucks and earth moving equipment based on specific plant operations. For example, EPA calculated earth moving equipment energy usage only if the plant operates an impoundment. To determine the potential decrease in fuel consumption, EPA estimated the amount of fuel saved by reducing the number of backhoes needed to dredge solids from ash impoundments, due to the reduction of wet sluice operations. See DCN SE01957 (*Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category*) for more information on the specific calculations used to estimate transportation fuel usage. Table XV–1 shows the net change in annual fuel consumption associated with the preferred BAT and PSES regulatory options (Options 3a, 3b, 3, and 4a).

To provide some perspective on the potential increase in annual electric energy consumption associated with the preferred regulatory options, EPA compared the estimated increase in energy usage (MWh) 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 power plant industry generated approximately 3,951 million MWh of energy 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 fuel consumption (gallons) estimated for the preferred BAT and PSES regulatory options to national fuel consumption estimates for motor vehicles in the United States. According to the 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.

TABLE XV–1—ENERGY USE ASSOCIATED WITH ELG OPTIONS 3a, 3b, 3, AND 4a

Non-water quality impact	Energy use associated with proposed rule			
	Option 3a	Option 3b	Option 3	Option 4a
Electrical Energy Usage (MWh)	112,000	160,753	303,300	472,369
Fuel (Thousand Gallons)	2,867	2,903	3,040	4,618

B. Air Pollution

The proposed ELGs are expected to affect air pollution through three main mechanisms: (1) 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; (2) additional transportation-related emissions due to the increased trucking of CCR waste to landfills; and (3) the change in the profile of electricity generation due to relatively higher cost to generate electricity at plants incurring compliance costs for the proposed ELGs. 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 Section XIV 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 operating transport vehicles, such as dump and vacuum trucks, dust suppression water trucks, and earth-moving equipment, which release criteria air pollutants and greenhouse gases when operated. Similarly, a decrease in energy use or vehicle operation will result in decreased air pollution.

To estimate the net air emissions associated with increased electrical energy use, EPA combined the energy usage estimates with air emission factors associated with electricity production to calculate air emissions associated with the incremental energy requirements for each of the proposed regulatory options. EPA used emission factors projected by IPM (ton/MWh) for nitrogen oxides, sulfur dioxide, and carbon dioxide to generate estimates of increased air emissions associated with increased energy production.

To estimate net air emissions associated with increased operation of transport vehicles, EPA used the MOBILE6.2 model and the California Climate Action Registry, General Reporting Protocol, Version 2.2 to identify air emission factors (gram per mile) for the air pollutants of interest. 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. EPA estimated the annual number of miles that dump or vacuum trucks moving ash or wastewater treatment solids to on- or offsite landfills would travel to comply with limits established by the proposed regulatory options. In addition to the trucks transporting the additional solid waste, EPA also estimated the annual number of miles that water trucks spraying water around landfills and ash unloading areas to control dust would travel. EPA used these estimates to calculate the net change in air emissions for this rulemaking.

EPA's analyses using IPM also predict changes in air emissions. The modeled output from IPM predicts changes in electricity generation due to compliance costs attributable to the proposed regulatory options. These changes in electricity generation are, in turn, predicted to affect the air emissions from steam electric power plants.

The net change in air emissions associated with the preferred BAT/PSES regulatory options (Options 3a, 3b, 3, and 4a) are shown in Tables XV–2 through XV–5. To provide some perspective on the potential changes in annual air emissions, EPA compared the estimated change in air emissions to the net amount of air emissions generated in a year by all electric power plants throughout the United States. Tables XV–2 through XV–4 present the estimated changes in air emissions based on the regulatory options, the total emissions generated by the electric power industry in 2009, based on eGRID, and the percent change in emissions associated with Options 3a, 3b, 3, and 4a. See DCN SE02025 (*Steam Electric Effluent Guidelines Non-Water Quality Impacts*) in the record for this rulemaking for more information.

TABLE XV–2—AIR EMISSIONS ASSOCIATED WITH BAT/PSES OPTION 3a

Non-water quality impact	Value associated with option 3a (million tons)	2009 Emissions by electric power industry (million tons)	Increase in emissions (%)
NO_X	[a] 0.000088–0.00109	1	0.0088–0.109
SO_X	[b] <0.000084	6	<0.0014
CO_2	[b] <0.130	2,403	<0.0054

[a] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 3a. Based on the values quantified for Option 3 for changes to air emissions projected by IPM, EPA calculated the range of emissions for NO_X. 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 larger than would be expected for Option 3a.

[b] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 3a. Based on the values quantified for Option 3 for 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 Option 3a. These SO_X and CO_2 emissions are considered maximum values because EPA expects that the air emission changes projected by IPM for Option 3a will also be negative (as they are for Options 3 and 4).

TABLE XV–3—AIR EMISSIONS ASSOCIATED WITH BAT/PSES OPTION 3b

Non-water quality impact	Value associated with option 3b (million tons)	2009 Emissions by electric power industry (million tons)	Increase in emissions (%)
NO_X	[a] 0.00011–0.00111	1	0.011–0.111
SO_X	[b] <0.00013	6	<0.0021
CO_2	[b] <0.149	2,403	<0.0062

[a] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 3b. Based on the values quantified for Option 3 for changes to air emissions projected by IPM, EPA calculated the range of emissions for NO_X. 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 larger than would be expected for Option 3b.

[b] EPA quantified the air emissions associated with additional electricity and additional transportation for Option 3b. Based on the values quantified for Option 3 for changes to air emissions projected IPM, which were negative, EPA decided not to include these IPM air emission changes in the calculated SO_X and CO_2 emissions for Option 3b. These SO_X and CO_2 emissions are considered maximum values because EPA expects that the air emission changes projected for IPM for Option 3b will also be negative (as they are for Options 3 and 4).

TABLE XV–4—AIR EMISSIONS ASSOCIATED WITH BAT/PSES OPTION 3

Non-water quality impact	Value associated with option 3 (million tons)	2009 Emissions by electric power industry (million tons)	Increase in emissions (%)
NO_X	0.00121	1	0.121
SO_X	−0.00273	6	−0.045
CO_2	−1.282	2,403	−0.053

TABLE XV–5—AIR EMISSIONS ASSOCIATED WITH BAT/PSES OPTION 4a

Non-water quality impact	Value associated with option 4a (million tons)	2009 Emissions by electric power industry (million tons)	Increase in emissions (%)
NO_X	[a] 0.00132	1	0.132
SO_X	[a] <−0.00258	6	<−0.043
CO_2	[a] <−1.106	2,403	<−0.046

[a] 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 Options 3 because they are more conservative (i.e., they overestimate the emissions). The contribution of NO_X is unchanged compared to Option 3 and 4; therefore, EPA assumed this would also be the contribution for Option 4a. For SO_X 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.

C. 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 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 ash or other combustion residuals generated. See DCN SE02025 (*Steam Electric Effluent Guidelines Non-Water Quality Impacts*) in the record for this rulemaking for more information.

To provide some perspective on the potential increase in annual solid waste generation associated with the preferred BAT/PSES regulatory options, EPA compared the estimated increase in solid waste generation for Options 3b, 3, and 4a [90] to the amount of solids generated in a year by electric power plants throughout the United States—approximately 134 billion tons. The increase in solid waste generation associated with Options 3b, 3 and 4a for BAT and PSES will be less than 0.001 percent of the total solid waste generated by all electric power plants.

D. 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 and bottom ash will eliminate or reduce water use associated with current wet sluicing operating systems. EPA estimated the reductions in water use based on the amount of sluice water discharged by each plant, multiplied by the percentage of intake water identified as make-up in the survey. The memorandum entitled *Steam Electric Effluent Guidelines Non-Water Quality Impacts,* located in the record for this rulemaking, provides more information.

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 recycling within their FGD systems based on the maximum operating chlorides concentration compared to the design maximum chlorides concentration. Based on this comparison, EPA estimated the reduction in intake water at a plant level based on the amount of water that could be recycled by the FGD system and multiplying by the percentage of intake water identified as make-up water in the industry survey. EPA's report entitled *Incremental Costs and Pollutant Removals for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category,* located in the record for this rulemaking, provides more information.

EPA estimates that power plants would reduce the use of water by 50 billion gallons per year (136 million gallons per day) under Option 3a, by 52 billion gallons per year (143 million gallons per day) under Option 3b, by 53 billion gallons per year (144 million gallons per day) under Option 3, and by 103 billion gallons per year (282 million gallons per day) under Option 4a.

XVI. Regulatory Implementation

A. 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. This 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 and through local 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.

1. Timing

For the reasons explained in Section VIII, EPA proposes that certain limitations and standards based on any of the eight main regulatory options being proposed today 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. See Section VIII.B for additional discussion regarding the implementation timing for the proposed BAT and PSES requirements.

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.

2. Applicability of NSPS/PSNS

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.

3. Legacy Wastes

For the reasons explained in Section VIII, EPA is proposing that certain 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

[90] As described previously, the preferred regulatory options for BAT and PSES for fly ash and bottom ash transport water are not expected to alter the amount of ash or other combustion residuals generated. Therefore, there is no increase for Option 3a and the increase for Option 4a is equal to the increase for Option 3.

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.[91] As proposed today, for direct dischargers such wastewater generated prior to that date (i.e., ''legacy'' wastewater) 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.

4. Compliance Monitoring

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 facility. Therefore, it may be 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 proposed 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 this proposed rule could require internal monitoring points. Section 14 of the TDD provides detailed discussion for various types of configurations. The following provides selected information from the TDD:

- FGD wastewater: Where an option proposes BAT/NSPS limitations for FGD wastewater that are not equal to existing BPT limitations,[92] 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. 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 proposed today.

For example, many plants currently treat their FGD wastewater and leachate in onsite surface impoundments. EPA envisions that, under this proposed 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 chose 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.

- 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. Under EPA's proposal, the plant could not demonstrate compliance with the applicable discharge prohibition by simply using the fly ash transport water 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. As an 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 Option 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 proposed today. For example, many plants currently treat their leachate in onsite surface impoundments. EPA envisions that, under the proposed requirements, 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

[91] Except where BAT is equivalent to BPT.

[92] Similarly applies to PSES and PSNS.

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 facility will also have to demonstrate compliance with the applicable FGD wastewater effluent limitations and standards.) Conversely, under the proposed requirements, EPA envisions some plants may choose to install tank-based leachate treatment systems whose effluent is discharged to the impoundment containing the legacy leachate. In this case, the plant would be required to demonstrate compliance with the proposed effluent limitations and standards for the newly generated combustion residual leachate at the effluent from the tank-based leachate treatment system and compliance with the BPT requirements for the commingled new/legacy leachate at the discharge from the impoundment.

B. 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 this notice. 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. See DCN SE03835 and DCN SE03868 for the SOPs and information on EPA's development of the SOPs.

In addition, as explained in Section VIII, 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 this 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 [93] for the wastewater matrix being analyzed is at or below the level of the effluent limit.

C. Upset and Bypass Provisions

A ''bypass'' is an intentional diversion of wastestreams from any portion of a treatment facility. An ''upset'' is an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. EPA's regulations concerning bypasses and upsets for direct dischargers are set forth at 40 CFR 122.41(m) and (n) and for indirect dischargers at 40 CFR 403.16 and 403.17.

D. 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.

1. Fundamentally Different Factors (FDF) Variance

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 in *Chemical Manufacturers Association* v. *Natural Resources Defense Council,* 470 U.S. 116, 124 (1985).

Subsequently, in the Water Quality Act of 1987, Congress added a new section to the 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

[93] 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.''

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).

2. Economic Variances

Section 301(c) of the CWA authorizes a variance from the otherwise applicable BAT effluent guidelines for nonconventional pollutants due to economic factors. The request for a variance from effluent limitations developed from BAT guidelines must normally be filed by the discharger during the public notice period for the draft permit. Other filing 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.*

3. Water Quality Variances

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.

4. 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. Furthermore, 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, or local sewage sludge requirements. 40 CFR 403.7(a)(3).

The United States Court of Appeals for the Third Circuit interpreted the CWA as requiring EPA to promulgate the comprehensive sewage sludge regulations pursuant to CWA Section 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. For sewage sludge that is land applied, removal credits may be available for an additional two metals and 14 organic pollutants. For sewage sludge that is placed on a surface disposal unit, removal credits may be available for an additional seven metals and 13 organic pollutants. For 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).

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

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Section 3(f)(1) of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in Chapter 12 of the BCA report. A copy of the analysis is available in the docket for this action and the analysis is briefly summarized here.

Table XVII–1 (drawn from Table 12–1 of the BCA report) provides the results of the benefit-cost analysis with both costs and benefits annualized over 24 years and discounted using a 3 percent discount rate. The table lists the eight options in order of increasing total social costs.

TABLE XVII–1—TOTAL MONETIZED ANNUALIZED BENEFITS AND COSTS OF THE BAT AND PSES REGULATORY OPTIONS

[Millions 2010 $, 3 percent discount rate] [a]

Regulatory option	Total social costs [b]	Total monetized benefits [c d e]
Option 3a	$185.2	([e])
Option 1	268.3	$82.0
Option 3b	281.4	([e])
Option 2	386.8	111.7
Option 3	572.0	311.7
Option 4a	954.1	([e])
Option 4	1,381.2	605.5
Option 5	2,328.8	434.1

[a] All costs and benefits were annualized over 24 years and using a 3 percent discount rate.

[b] Total social costs include compliance costs to facilities.

[c] Mean benefit estimates. Values include partial human health benefits only for reaches that receive direct discharges from steam electric plants. Values for Options 1, 2, and 5 do not include air-related benefits.

[d] EPA estimated certain benefits for Options 3 and 4 only. Total benefits for Options 1, 2, and 5 are therefore understated. See Section XIV and Table XIV–8.

[e] EPA did not estimate benefits for Options 3a, 3b and 4a. The benefits of Option 4a are expected to be between those of Options 3 and 4.

EPA also analyzed the employment effects of the proposed ELGs. The results of that analysis are summarized in Section XI.E.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. However, the Office of Management and Budget (OMB) has previously approved the information collection requirements contained in the existing regulations 40 CFR part 423 under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control number 2040–0281. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

EPA estimated small changes in monitoring costs due to additional metals for which EPA is proposing limits and standards; the Agency accounted for these costs as part of its analysis of the economic impacts of the proposed ELGs. However, plants will also realize certain savings by no longer monitoring effluent that would cease to exist under the proposed ELGs. The net changes in monitoring and reporting are expected to be minimal, and EPA consequently did not revise its information collection burden estimate.

EPA does not believe that the proposed rule would lead to additional costs to permitting authorities. The proposed rule would not change permit application requirements or the associated review, it would not increase the number of permits issued to steam electric plants, and nor it increase the efforts involved in developing or reviewing such permits. In the absence of nationally applicable BAT requirements, as appropriate, permitting authorities are directed to establish technology-based effluent limitations using their use best professional judgment (BPJ) to establish site-specific requirements. EPA has data that demonstrates that permitting authorities that establish technology-based effluent limitations on a BPJ basis based on site-specific conditions can spend significant time effort and resources doing so. Establishing nationally applicable BAT requirements that eliminate the need to develop BPJ-based limitations would make permitting easier and less costly in this respect. As explained in Section XVI, under this rule, permitting authorities would be required to determine, for one permit cycle, on a facility-specific basis, what date is ''as soon as possible.'' This one-time burden, however, would be no more excessive than the existing burden to develop technology-based effluent limitations on a BPJ basis; in fact, it would likely be less burdensome. Nevertheless, EPA conservatively estimated no net change (i.e., increase or decrease) in the cost burden to federal or state governments associated with this proposal.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice-and-comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

1. Definition of Small Entities and Estimation of the Number of Small Entities Subject to These Proposed ELGs

For purposes of assessing the impacts of this proposed rule on small entities, small entity is defined as either a: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. In reaching entity size determinations, EPA assumed that all federal or state entities owning steam electric plants affected by this rulemaking are not small entities.

The SBA criteria for identifying small, non-government entities in the electric power industry are as follows:

- For non-government entities with electric power generation as a primary business, small entities are those with total annual electric output less than 4 million MWh;
- For non-federal or state jurisdictions, small entities are those with a population of less than 50,000.
- For entities with a primary business other than electric power generation, the relevant size criteria are based on revenue or number of employees by NAICS sector (see Table XVII–2).

TABLE XVII–2—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR STEAM ELECTRIC GENERATORS WITH A PRIMARY BUSINESS OTHER THAN ELECTRIC POWER GENERATION [a]

NAICS Code	NAICS description	SBA size standard [b]
211111	Crude Petroleum and Natural Gas Extraction	500 Employees.
212111	Bituminous Coal and Lignite Surface Mining	500 Employees.
213112	Support Activities for Oil and Gas Operations	$7 million in revenue.
221210	Natural Gas Distribution	500 Employees.
221310	Water Supply and Irrigation Systems	$7 million in revenue.
221330	Steam and Air-Conditioning Supply	$12.5 million in revenue.
237130	Power and Communication Line and Related Structures Construction	$33.5 million in revenue.
324110	Petroleum Refineries	1,500 Employees.
332410	Power Boiler and Heat Exchanger Manufacturing	500 Employees.
333611	Turbine and Turbine Generator Set Unit Manufacturing	1,000 Employees.
423510	Metal Service Centers and Other Metal Merchant Wholesalers	100 Employees.
486110	Pipeline Transportation of Crude Oil	1,500 Employees.
522110	Commercial Banking	$175 million in assets.
523110	Investment Banking and Securities Dealing	$7 million in revenue.
523910	Miscellaneous Intermediation	$7 million in revenue.
523920	Portfolio Management	$7 million in revenue.
524113	Direct Life Insurance Carriers	$7 million in revenue.
524126	Direct Property and Casualty Insurance Carriers	1,500 employees.
525910	Open-End Investment Funds	$7 million in revenue.
541614	Process, Physical Distribution and Logistics Consulting Services	$14 million in revenue.
541690	Other Scientific and Technical Consulting Services	$14 million in revenue.
551111	Offices of Bank Holding Companies	$7 million in revenue.
551112	Offices of Other Holding Companies	$7 million in revenue.
562219	Other Nonhazardous Waste Treatment and Disposal	$12.5 million in revenue.[c]

[a] Certain plants affected by this rulemaking are owned by non-government entities whose primary business is not electric power generation.
[b] Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective October 1, 2012).
[c] EPA is aware that SBA revised the size standard applicable to this sector, effective January 7, 2013 (from $12.5 million in revenue to $35.5 million in revenue); EPA used the size standards effective at the time the analyses were completed and will update the size standards as part of revisions to support final rulemaking.

EPA identified the domestic parent entity of each steam electric plant and obtained the entity's revenue from the Steam Electric industry survey or from publicly available data sources. In this analysis, the domestic parent entity associated with any given plant is defined as that entity that has the largest ownership share in the plant. To determine whether these entities are small entities based on the size criteria outlined above, EPA compared the relevant measure for the identified parent entities to the appropriate SBA size criterion.

EPA used alternative sample-weighting approaches, which provide a range of estimates of the numbers of small entities and affected plants owned by these small entities (see Chapter 8 in the RIA for details of methodology used to develop weighted estimates). The results of this analysis using both weighting approaches are summarized below.

EPA estimates that 243 to 507 entities own steam electric plants subject to this proposal. Applying the small entity identification criteria, EPA estimates that 97 to 170 of these entities are small (see Table XVII–3). Municipalities make up the largest number of small entities owning steam electric plants under the lower bound estimate (37 out of 97) and are also a significant fraction of small entities under the upper bound estimate (46 out of 170). Small entities owning steam electric plants as a percentage of total entities range, by ownership category, from 14 to 17 percent for other political subdivision, to 47 to 51 percent for nonutility and 45 to 57 percent for municipality.

EPA determined that 14 small entities own steam electric plants expected to incur compliance costs under at least one of the eight regulatory options, for either of the two bounding cases.

TABLE XVII–3—NUMBER OF ENTITIES OWNING STEAM ELECTRIC PLANTS BY SECTOR AND SIZE

[Assuming two different ownership cases] [a]

Ownership type	Lower bound estimate of number of entities owning steam electric plants [b]			Upper bound estimate of number of entities owning steam electric plants [b]		
	Total	Small [c]	% Small	Total	Small [c]	% Small
Investor-Owned Utilities	97	27	27.8	244	64	26.3
Nonutilities	35	18	51.4	73	34	46.8
Rural Electric Cooperatives	30	13	43.3	52	21	40.7
Municipality	65	37	56.9	101	46	45.3
Other Political Subdivision	12	2	16.7	30	4	14.2
Federal [a]	2	0	0.0	4	0	0.0
State [a]	2	0	0.0	2	0	0.0%
Tribal	0	0	N/A	0	0	N/A
All Entity Types	243	97	39.9	507	170	33.5

[a] In 19 instances, a plant is owned by a joint venture of two entities; in one instance, the plant is owned by a joint venture of three entities.

[b] Of these, 92 entities, 14 of which are small, own steam electric plants that are expected to incur compliance costs under at least one regulatory option under both Case 1 and Case 2.
[c] EPA was unable to determine size for 10 parent entities; for this analysis, these entities are assumed to be small.

In total, small entities own a total of 189 steam electric plants, or 18 percent of the total universe of 1,079 steam electric plants. Of these, EPA determined that 14 plants may incur compliance costs under at least one of the eight regulatory options.

EPA notes that its proposal (discussed in Section VIII) to set the BAT equal to BPT for existing generating units with a total nameplate generating capacity of 50 MW or less for all of the eight proposed regulatory options will reduce the potential impacts of the proposed rule on small entities and municipalities. The rulemaking record indicates that establishing a size threshold for the BAT would preferentially minimize some of the economic impacts expected on municipalities and small entities. This is the result, in particular, of the fact that 37 percent of small entities own a steam electric generating unit with a capacity of 50 MW or smaller. This stands in contrast to the 22 percent of all firms (both large and small entities) that own such a unit and the 18 percent of large entities that own one. Moreover, more than half (54 percent) of generating units owned by small entities are 50 MW or smaller. In contrast, only seven percent of generating units owned by large entities are 50 MW or smaller. Municipalities also tend to own smaller generating units, with 30 percent of municipalities and 42 percent of municipal-owned units being affected by the 50 MW size threshold.

EPA requests comment on the proposed 50 MW threshold applicable to discharges of the wastestreams described under each of the preferred options, and as well as other possible thresholds for small units.

2. Statement of Basis

As described above, EPA began its assessment of the impact of regulatory options on small entities by first estimating the number of small entities owning Steam Electric plants that would be subject to these proposed ELGs. EPA then assessed whether these small entities would be expected to incur costs that constitute a significant impact; and whether the number of those small entities estimated to incur a significant impact represent a substantial number of small entities.

To assess whether small entities' compliance costs might constitute a significant impact, EPA summed annualized compliance costs for the steam electric plants determined to be owned by a given small entity and calculated these costs as a percentage of entity revenue (cost-to-revenue test). EPA compared the resulting percentages to impact criteria of 1 percent and 3 percent of revenue. Small entities estimated to incur compliance costs exceeding one or more of the 1 percent and 3 percent impact thresholds were identified as potentially incurring a significant impact.

EPA used alternative sample-weighting approaches, which provide a range of estimates of the numbers of small entities and steam electric plants owned by these small entities. The results of this analysis using both weighting approaches are summarized below. Table XVII–4 presents the estimated numbers of small entities incurring costs exceeding 1 percent and 3 percent of revenue. For more information on this analysis in general and the weighting approaches in particular, see Chapter 7 in the RIA report.

TABLE XVII–4—ESTIMATED COST-TO-REVENUE IMPACT ON SMALL ENTITIES OWNING STEAM ELECTRIC PLANTS SUBJECT TO THIS PROPOSED RULE

[Excluding those below the size threshold]

Regulatory option	Cost ≥1% of revenue		Cost ≥3% of revenue	
	Number of small entities	% of small affected entities [b]	Number of small entities [a]	% of small affected entities [b]
Lower bound estimate of number of entities owning steam electric plants				
Option 3a	0	0.0	0	0.0
Option 3b	0	0.0	0	0.0
Option 1	3	3.1	3	3.1
Option 2	5	5.2	3	3.1
Option 3	5	5.2	3	3.1
Option 4a	6	6.2	4	4.1
Option 4	12	12.4	4	4.1
Option 5	12	12.4	7	7.2
Upper bound estimate of number of entities owning steam electric plants				
Option 3a	0	0.0	0	0.0
Option 3b	0	0.0	0	0.0
Option 1	3	1.8	3	1.8
Option 2	5	2.9	3	1.8
Option 3	5	2.9	3	1.8
Option 4a	6	3.5	4	2.4
Option 4	12	7.1	4	2.4
Option 5	12	7.1	7	4.1

[a] The number of entities with cost-to-revenue ratios exceeding 3 percent is a subset of the number of entities with such ratios exceeding 1 percent.
[b] Percentage values were calculated relative to the total of 97 (Case 1) and 170 (Case 2) small entities owning steam electric plants.

As reported in Table XVII–4, EPA estimates that between 0 and 12 small entities owning steam electric plants will incur costs exceeding 1 percent of revenue, and that between 0 and 7 small entities owning steam electric plants will incur costs exceeding 3 percent of revenue, depending on the regulatory option. This is out of an estimated total of 97 to 170 small entities owning steam electric plants. The impact findings in terms of *numbers* of entities affected at different levels, and the *percentage* of small entities by ownership category vary by regulatory option. Overall across entity types, no small entity is estimated to have costs exceeding 1 percent of revenue under Options 3a and 3b. Under Option 3, 5 small entities are estimated to have costs exceeding 1 percent of revenue, and 3 small entities have costs exceeding 3 percent of revenue. Under Option 4a, 6 small entities are estimated to have costs 1 percent of revenue or higher under Option 3, and 4 small entities have costs 3 percent of revenue or higher. Table XVII–5 presents the distribution of these entities by ownership type for Options 3 and 4a (Options 3a and 3b are not included in the table since no small entity has costs 1 percent of revenue or higher under these two options). As shown in the table, small entities with costs 1 percent of revenue or greater under Option 3 include 2 cooperatives and 3 municipalities. Under Option 4a, 2 cooperatives and 4 municipalities have costs 1 percent of revenue or greater. The cost-to-revenue test is one of several metrics EPA used to determine the impacts of the proposed ELGs. As discussed in Section XI.D, EPA also looked at impacts in the context of the electricity market-level effects to assess economic achievability.

TABLE XVII–5—ESTIMATED COST-TO-REVENUE IMPACT ON SMALL ENTITIES OWNING STEAM ELECTRIC PLANTS UNDER THE PREFERRED BAT AND PSES OPTIONS (OPTIONS 3 AND 4a), BY OWNERSHIP TYPE (EXCLUDING THOSE BELOW THE SIZE THRESHOLD) [a]

Regulatory option	Lower bound estimate of number of entities owning steam electric plants				Upper bound estimate of number of entities owning steam electric plants			
	Cost ≥1% of revenue		Cost ≥3% of revenue		Cost ≥1% of revenue		Cost ≥3% of revenue	
	Number of small entities	% of small affected entities [c]	Number of small entities [b]	% of small affected entities [c]	Number of small entities	% of small affected entities [c]	Number of small entities [b]	% of small affected entities [c]
Option 3:								
Cooperative	2	15.4	2	15.4	2	9.4	2	9.4
Investor-Owned	0	0.0	0	0.00	0	0.0	0	0.0
Municipality	3	8.1	1	2.7	3	6.5	1	2.2
Nonutility	0	0.0	0	0.0	0	0.0	0	0.0
Other Political Subdivision	0	0.0	0	0.0	0	0.0	0	0.0
Total	5	5.2	3	3.1	5	2.9	3	1.8
Option 4a:								
Cooperative	2	15.4	2	15.4	2	9.4	2	9.4
Investor-Owned	0	0.0	0	0.0	0	0.0	0	0.0
Municipality	4	10.8	2	5.4	4	8.7	2	4.4
Nonutility	0	0.0	0	0.0	0	0.0	0	0.0
Other Political Subdivision	0	0.0	0	0.0	0	0.0	0	0.0
Total	6	6.2	4	4.1	6	3.5	4	2.4

[a] Options 3a and 3b are not included in the table since no small entity has costs 1 percent of revenue or higher under these two preferred options.

[b] The number of entities with cost-to-revenue ratios exceeding 3 percent is a subset of the number of entities with such ratios exceeding 1 percent.

[c] Percentage values were calculated relative to the total of 97 (Case 1) and 170 (Case 2) small entities owning steam electric plants. EPA expects that Case 2 is a more likely ownership scenario for small entities (e.g., small municipalities) as small entities may be less likely to own multiple non-surveyed steam electric plants. See RIA Chapter 8 for details.

Based on this analysis, EPA determines that the small entity impact levels for the preferred BAT and PSES options (Options 3a, 3b, 3 and 4a) support a finding of no significant impact on a substantial number of small entities (No SISNOSE). Where not zero altogether, the numbers of small entities incurring costs exceeding either the 1 or 3 percent of revenue impact threshold are small in the absolute and represent small percentages of the total estimated number of small entities (see Table XVII–5). For more details on this analysis, see Chapter 8 of the RIA report.

3. Certification Statement

After considering the economic impacts of these proposed ELGs on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. EPA bases its finding on the low number of small entities estimated to incur costs exceeding one and/or three percent of revenue, and the small percentage that these entities represent within the total of small entities owning steam electric plants. EPA continues to be interested in the potential impacts of the proposed rule on small entities and welcomes comments on issues related to potential impacts.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. This rule contains a federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, EPA has prepared under Section 202 of the UMRA a written statement, which is summarized below (see Chapter 9 in the RIA report for more details).

Consistent with the intergovernmental consultation provisions of Section 204 of the UMRA EPA has initiated consultations with governmental entities affected by this rule. As described in Sections XVII.E, EPA held consultation meetings with elected officials or their designated employees in October 2011 to ensure their meaningful and timely input into the proposed ELGs development. EPA also conducted outreach with several intergovernmental associations representing elected officials. As described in Section XVII.F, EPA also initiated consultation and coordination with federally-recognized tribal governments in August 2011 and continued this government-to-government dialogue in March 2012.

Consistent with Section 205, EPA has identified and considered a reasonable number of regulatory alternatives. EPA considered and analyzed several alternative regulatory options to determine BAT/BADCT. These regulatory options are discussed in Section VIII of this preamble. These options included a range of technology-based approaches. As discussed in detail in Section VIII, EPA is proposing Options 3a, 3b, 3 and 4a as the preferred BAT and PSES options because they are technologically available, economically achievable, and have acceptable non-water quality environmental impacts. EPA is proposing Option 4 as the preferred NSPS and PSNS option because it is technologically available and demonstrated, poses no barrier to entry, and has acceptable non-water quality environmental impacts.

This rule is not subject to the requirements of Section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. For its assessment of the impact of compliance requirements on small governments (i.e., governments with a population of less than 50,000), EPA compared total costs and costs per plant estimated to be incurred by small governments with the costs estimated to be incurred by large governments. EPA also compared costs for small government-owned plants with those of non-government-owned facilities. The Agency evaluated both the average and maximum annualized cost per plant. Chapter 9 of the RIA report provides details of these analyses. In all of these comparisons, both for the cost totals and, in particular, for the average and maximum cost per plant, the costs for small government-owned facilities were less than those for large government-owned facilities or for small non-government-owned facilities. On this basis, EPA concludes that the compliance cost requirements of the proposed Steam Electric ELGs would not significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

Under Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with state and local officials early in the process of developing the proposed action.

EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs.

As discussed in Section XI, EPA anticipates that this proposed action will not impose incremental administrative burden on states from issuing, reviewing, and overseeing compliance with discharge requirements. However, EPA has identified 168 steam electric plants owned by state or local government entities, out of which less than 10 percent may incur costs under one of the preferred regulatory Options. Specifically, EPA projects that five government-owned plants incur compliance costs under BAT/PSES regulatory Option 3a, six plants incur compliance costs under Option 3b, 14 plants incur compliance costs under Option 3, and 15 plants incur compliance costs under Option 4a. EPA estimates that the maximum compliance cost in any one year to governments (excluding federal government) for the eight regulatory options ranges from $13.8 million under Option 3a to $406.2 million under Option 5. Options 3b, 3 and 4a have maximum compliance costs in any one year to governments of $31.9 million, $109.5 million and $141.8 million, respectively (see Chapter 9 of the RIA report for details). From these cost values, EPA determined that the proposed ELGs contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, in any one year. Based on this information, EPA finds that the action may impose substantial direct compliance costs on state or local governments. Accordingly, EPA provides the following federalism summary impact statement as required by Section 6(b) of Executive Order 13132.

EPA consulted with elected officials or their representative national organizations early in the process of developing the proposed action to permit them to have meaningful and timely input into its development.

EPA invited government officials to a consultation meeting held on October 11, 2011. EPA conducted outreach with several intergovernmental associations representing elected officials and encouraged their members to participate in the meeting, including the National Governors Association, the National Conference of State Legislatures, the Council of State Governments, the National Association of Counties, the National League of Cities, the U.S. Conference of Mayors, the County Executives of America and the National Associations of Towns and Townships.

Over 50 participants attended the consultation by phone and another 20 attended the meeting in person. EPA representatives were also present. Participants raised concerns during the meeting and in written comments regarding the technology options, pollutant removal effectiveness, costs of specific technologies and overall costs, impacts on small generating units and on small governments, and generally requested more detailed information. They also expressed their concern with regulating the industry at this time given the difficult economic conditions.

As explained in Section VIII, under all eight proposed regulatory options, EPA is proposing differentiated requirements for oil-fired generating units and units 50 MW or less. EPA believes these differentiated requirements will alleviate some of the concerns raised above. Further, as explained in Section XI, EPA's analysis demonstrates that the proposed requirements are economically achievable for the steam electric industry as a whole and for plants owned by state or local government entities. EPA is including in the docket for this action a memorandum that provides a response to the comments it received through this consultation. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on the proposed ELGs from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It would not have substantial direct effects on tribal governments, on the relationship between the federal government and the Indian tribes, or the distribution of power and responsibilities between the Federal government and Indian tribes as specified in Executive Order 13175. EPA's analyses show that no facility subject to these proposed ELGs is owned by tribal governments. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, EPA consulted with tribal officials in developing this action. EPA initiated consultation and coordination with federally recognized tribal governments in August 2011, sharing information about the steam electric effluent guidelines rulemaking with the National Tribal Caucus and the National Tribal Water Council. EPA continued this government-to-government dialogue and, in March 2012, invited tribal representatives to participate in further discussions about the rulemaking process and objectives, with a focus on identifying specific ways that the rulemaking may affect tribes. EPA mailed an invitation letter directly to those tribes that were preliminarily identified as potentially affected by the rulemaking, as well extended the invitation via email to all federally-recognized tribal governments encouraging their participation in the consultation process. The consultation process ended on April 17, 2012 and no comments were received from any tribal representative. For further information regarding the consultation process and supplemental materials provided to tribal representatives please go to the steam electric power generating effluent guidelines Web site at this link: *http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm#point8.* EPA specifically solicits additional comment on this proposed action from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This proposed action's health and risk assessments are summarized in Section XIV.D.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

The Agency analyzed the potential energy effects of these proposed ELGs. The potentially significant effects of this rule on energy supply, distribution or use concern the electric power sector. EPA's analysis found that the proposed ELGs would not cause effects in the electric power sector that would constitute a significant adverse effect under Executive Order 13211. Namely, the Agency's analysis found that this rule would not reduce electricity production in excess of 1 billion kilowatt hours per year or in excess of 500 megawatts of installed capacity, and therefore would not constitute a significant regulatory action under Executive Order 13211.

For more detail on the potential energy effects of this proposal, see Chapter 10 in the RIA report.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 12(d) (15 U.S.C. 272 note), directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking does not involve technical standards, for example, in the measurement of pollutant loads. Nothing in this proposed rule would prevent the use of voluntary consensus standards for such measurement where available, and EPA encourages permitting authorities and regulated entities to do so. Therefore, EPA is not considering the use of any voluntary consensus standards.

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

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

To meet the objectives of Executive Order 12898, EPA examined whether these proposed ELGs will have potential environmental justice concerns in the areas affected by steam electric plant discharges. The Agency analyzed the demographic characteristics of the populations currently exposed to steam electric plant discharges through receiving reaches (i.e., populations located within 100 miles of the affected reaches, also referred to as the ''benefit regions'' in the rest of this discussion) to determine whether minority and or low-income populations are subject to disproportionally high environmental impacts. Chapter 10 of the RIA provides a detailed discussion of the environmental justice analysis.

EPA compared demographic data from the 2010 Census for benefit regions with corresponding characteristics at the state and national levels. This analysis focuses on the spatial distribution of minority and low-income groups to determine whether these groups are more or less represented in the populations expected to benefit from the proposed ELGs. The demographic characteristics that EPA analyzed include: percent African Americans, percent Native American, Eskimo, or Aleut, percent Asian or Pacific Islander, percent of the population below the poverty level, and median income. This analysis shows that approximately 14 percent of households in affected populations are below the poverty threshold, and 25 percent of them are minority, compared with national averages of 14 percent and 36 percent, respectively. Additionally, the median household income in affected populations is $48,579, while it is $51,914 nationally.

Of the 344 benefit regions defined in the analysis (within 100 miles of an affected plant), 28 regions (8 percent) may have Environmental Justice concerns under all three metrics, 79 regions (23 percent) under two metrics, and 194 regions (56 percent) under one metric. Forty-three regions (13 percent) would not be considered has having Environmental Justice concerns under any of the metrics.

This analysis indicates that minority and low-income communities are expected to benefit as much as anyone from the proposed ELGs.

Appendix A: Definitions, Acronyms, and Abbreviations Used in This Notice

The following acronyms and abbreviations are used in this document.

Administrator—The Administrator of the U.S. Environmental Protection Agency.

Agency—U.S. Environmental Protection Agency.

BAT—Best available technology economically achievable, as defined by Sections 301(b)(2)(A) and 304(b)(2)(B) of the CWA.

BCT—The best control technology for conventional pollutants, applicable to discharges of conventional pollutants from existing industrial point sources, as defined by Sections 301(b)(2)(E) and 304(b)(4) of the CWA.

BMP—Best management practice.

Bottom ash—The ash, including boiler slag, that drops out of the furnace gas stream in the furnace and which settles in the furnace or are dislodged from furnace walls. Economizer ash is included when it is collected with bottom ash.

BPT—The best practicable control technology currently available, applicable to effluent limitations, for industrial discharges to surface waters, as defined by Sections 301(b)(1) and 304(b)(1) of the CWA.

CBI—Confidential Business Information.

CCR—Coal Combustion Residuals.

Clean Water Act (CWA)—The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. Section 1251 *et seq.*), as amended *e.g.,* by the Clean Water Act of 1977 (Pub. L. 95–217), and the Water Quality Act of 1987 (Pub. L. 100–4).

Combustion Residual Leachate—Leachate from landfills or surface impoundments 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, leak, and leakage, which are generally used in reference to leachate from an impoundment. Includes landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility.

Direct Discharger—A facility that discharges or may discharge treated or untreated wastewaters into waters of the United States.

DOE—Department of Energy.

Dry bottom ash handling system—A system that does not use water to convey bottom ash away from the boiler. It includes systems that collect and convey the ash without any use of water, as well as systems in which bottom ash is mechanically or pneumatically conveyed away from the boiler.

Dry fly ash handling system—A system that does not use water as the transport medium to convey fly ash away from particulate collection equipment.

EIA—Energy Information Administration.

EO—Executive Order.

EPA—U.S. Environmental Protection Agency.

Facility — *All property owned, operated, leased, or under the control of the same person or entity.*

Flue Gas Desulfurization (FGD) Wastewater—Any process wastewater generated specifically from the wet flue gas desulfurization scrubber system, including any solids separation or solids dewatering processes.

Flue Gas Mercury Control (FGMC) System—An air pollution control system installed or operated for the purpose of removing mercury from flue gas.

Flue Gas Mercury Control Wastewater—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.

Fly Ash—The ash that is carried out of the furnace by the gas stream and collected by mechanical precipitators, electrostatic precipitators, and/or fabric filters. Economizer ash is included when it is collected with fly ash. Ash collected in wet scrubber air pollution control systems whose primary purpose is particulate removal is not included.

Gasification Wastewater—Wastewater from all sources at an integrated gasification combined cycle operation except those for which specific limitations are otherwise established. Gasification wastewater includes, but is not limited to the following: 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 recover unit blowdown.

IPM—Integrated Planning Model.

Landfill—A disposal facility or part of a facility where solid waste, sludges, or other process residuals are placed in or on any natural or manmade formation in the earth for disposal and which is not a storage pile, a land treatment facility, a surface impoundment, an underground injection well, a salt dome or salt bed formation, an underground mine, a cave, or a corrective action management unit.

Low Volume Waste Sources—Wastewater from all sources including, but not limited to: 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 and carbon capture wastewater are not included.

NAICS—North American Industry Classification System.

NSPS, or New Source Performance Standards, applicable to industrial facilities whose construction is begun after the effective date of the final regulations. See 40 CFR 122.2.

ORCR—Office of Resource Conservation and Recovery.

PSES—Pretreatment Standards for Existing Sources.

PSNS—Pretreatment Standards for New Sources.

Publicly Owned Treatment Works (POTW)—Any device or system, owned by a state or municipality, used in the treatment (including recycling and reclamation) of municipal sewage or industrial wastes of a liquid nature that is owned by a state or municipality. This includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment. See 40 CFR 122.2.

RCRA—The Resource Conservation and Recovery Act of 1976, 42 U.S.C. 6901 *et seq.*

RFA—Regulatory Flexibility Act.

SBA—Small Business Administration.

Surface Impoundments—A facility or part of a facility which is a natural topographic depression, man-made excavation, or diked or dammed area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid process wastes or process wastes containing free liquids, and which is not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

UMRA—Unfunded Mandates Reform Act.

Wet bottom ash handling system—A system in which bottom ash is conveyed away from the boiler using water as a transport medium. Wet bottom ash systems typically send the ash slurry to dewatering bins or a surface impoundment.

Wet FGD system—Wet FGD systems capture sulfur dioxide from the flue gas using a sorbent that has mixed with water to form a wet slurry, and that generates a water stream that exits the FGD scrubber absorber.

Wet fly ash handling system—A system that conveys fly ash away from particulate removal equipment using water as a transport medium. Wet fly ash systems typically dispose of the ash slurry in a surface impoundment.

List of Subjects 40 CFR Part 423

Environmental protection, Electric power generation, Power plants, Waste treatment and disposal, Water pollution control.

Dated: April 19, 2013.

Bob Perciasepe,

Acting Administrator.

Therefore, 40 CFR chapter I is proposed to be amended as follows:

PART 423—STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

■ 1. The authority citation for part 423 is revised to read as follows:

Authority: Secs. 101; 301; 304(b), (c), (e), and (g); 306; 307; 308 and 501, Clean Water Act (Federal Water Pollution Control Act Amendments of 1972, as amended; 33 U.S.C. 1251; 1311; 1314(b), (c), (e), and (g); 1316; 1317; 1318 and 1361).

■ 2. Section 423.10 is revised as follows:

§ 423.10 Applicability.

The provisions of this part apply to discharges resulting from the operation of a generating unit by an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation, and which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (e.g., petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium. This part applies to discharges associated with both the combustion turbine and steam turbine portions of a combined cycle generating unit. Facilities defined as new sources under the 1982 new source performance standards specified in §§ 423.15(a) and 423.17(a) of this part continue to be subject to those standards. Units that qualify as 1982 new sources are also subject to revised BAT effluent limitations specified in § 423.13 of this part (for direct dischargers) or the revised pretreatment standards specified in § 423.16 of this part (for indirect dischargers). These revised limitations and standards constitute amendments to the new source performance standards applicable to 1982 new sources.

■ 3. Section 423.11 is amended by:

■ a. Revising paragraphs (b) and (e); and

■ b. Adding paragraphs (n) through (u).

The revised and added paragraphs read as follows:

§ 423.11 Specialized definitions.

* * * * *

(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 wet 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 a gas stream and collected by a capture device such as a mechanical precipitator, electrostatic precipitator, 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.

* * * * *

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

(o) The term flue gas mercury control 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 or bottom ash from the ash collection equipment and has direct contact with the ash.

(q) The term gasification wastewater means any process wastewater generated from a system used to create synthesis gas from fuels such as coal or petroleum coke. Gasification wastewater includes, but is not limited to, the following: slag handling wastewater, sour/grey water (which includes condensate generated for 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 landfills or surface impoundments containing residuals from the combustion of fossil or fossil-derived fuel. Leachate includes liquid, including any suspended or dissolved constituents in the liquid, that has percolated through or drained from waste or other materials placed 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, 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.

■ 4. Section 423.12 is amended by:

■ a. Revising paragraphs (b)(11) and (12); and

■ b. Adding paragraph (b)(13).

The revised and added paragraphs read as follows:

§ 423.12 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).

* * * * *

(b) * * *

(11) The quantity of pollutants discharged in FGD wastewater, flue gas mercury control wastewater, combustion residual leachate, or gasification wastewater shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration listed in the following table:

Pollutant or pollutant property	BPT effluent limitations	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

(12) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of the any mass based limitations specified in paragraphs (b)(3) through (b)(11) of this section. Concentration limitations shall be those concentrations specified in this section.

(13) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b)(1) through (b)(12) of this section attributable to each controlled waste source shall not exceed the specified limitations for that waste source.

■ 5. Section 423.13 is amended by:
■ a. Adding paragraph (f);
■ b. Revising paragraphs (g) and (h); and
■ c. Adding paragraphs (i) through (n).

§ 423.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

* * * * *

(f)(1) Except for those discharges to which paragraph (f)(2) of this section applies, the quantity of pollutants discharged in nonchemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of nonchemical metal cleaning wastes times the concentration listed in the following table:

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
Copper, total	1.0	1.0
Iron, total	1.0	1.0

(2) For those discharges of nonchemical metal cleaning waste that are currently authorized pursuant to limitations based on requirements in § 423.12(b)(3) for low-volume waste, the quantity of pollutants discharged in nonchemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of nonchemical metal cleaning wastes times the concentration listed in § 423.12(b)(3).

(g)(1) Except for those discharges to which paragraph (g)(2) of this section applies, dischargers must meet the effluent limitations in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. These effluent limitations apply to pollutants in FGD wastewater generated on or after the date the permitting authority has determined is as soon as possible. Such effluent limitations shall not allow the quantity of pollutants in FGD wastewater to exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	8	6
Mercury, total (ng/L)	242	119
Selenium, total (ug/L)	16	10
Nitrate/nitrate as N (mg/L)	0.17	0.13

(2) For any electric generating unit with a total nameplate capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in § 423.12(b)(11).

(3) A discharger must demonstrate compliance with the effluent limitations in paragraph (g)(1) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the FGD wastewater in any other plant process or commingling of the FGD wastewater with any water or other process wastewater, except for any combustion residual leachate or any other FGD wastewater. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

Note to (g): All proposed revisions to § 423.13(g) reflect proposed Option 4a, Option 3, and Option 3b (for units located at facilities with a total wet-scrubbed capacity of 2,000 MW or more), only. Under proposed Option 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), BAT would continue to need to be determined on a site-specific basis using best professional judgment.

(h)(1) Except for those discharges to which paragraph (h)(2) of this section applies, dischargers must meet the discharge prohibition in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. There shall be no discharge of wastewater pollutants from fly ash transport water generated on or after the date the permitting authority determines is as soon as possible. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in fly ash transport water shall not exceed the quantity determined by multiplying the flow of fly ash transport water times the concentration listed in § 423.12(b)(4).

(i)(1) Except for those discharges to which paragraph (i)(2) of this section applies, dischargers must meet the discharge prohibition in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. There shall be no discharge of wastewater pollutants from flue gas mercury control wastewater generated on or after the date the permitting authority determines is as soon as possible. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in flue gas mercury control wastewater shall not exceed the quantity determined by multiplying the flow of flue gas mercury control wastewater times the concentration listed in § 423.12(b)(11).

(j)(1) Except for those discharges to which paragraph (j)(2) of this section applies, dischargers must meet the effluent limitations in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. Such effluent limitations shall not allow the quantity of pollutants in gasification wastewater to exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	4	(1)
Mercury, total (ng/L)	1.76	1.29
Selenium, total (ug/L)	453	227
Total dissolved solids (mg/L)	38	22

1 This regulation does not specify this type of limitation for this pollutant; however, permitting authorities may do so as appropriate.

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in § 423.12(b)(11).

(3) A discharger must demonstrate compliance with the effluent limitations in paragraph (j)(1) of this section, as applicable, by monitoring for all pollutants (except pH) at a point 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. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

(k)(1) Except for those discharges to which paragraph (k)(2) of this section applies, dischargers must meet the discharge prohibition in this paragraph by a date determined by the permitting authority that is as soon as possible within the next permit cycle beginning July 1, 2017. There shall be no discharge of wastewater pollutants from bottom ash transport water generated on or after the date the permitting authority determines is as soon as possible. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 400 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration in § 423.12(b)(4).

Note to (k): All proposed revisions to § 423.13(k) reflect proposed Option 4a, only. Under proposed Option 3, Option 3a, and Option 3b, § 423.13(k) would be revised to specify that the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration in § 423.12(b)(4).

(l) The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of leachate times the concentration listed in § 423.12(b)(11).

(m) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (b) through (l) of this section. Concentration limitations shall be those concentrations specified in this section.

(n) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (m) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

■ 6. Section 423.15 is amended by revising paragraphs (a) and (b) to read as follows:

§ 423.15 New source performance standards (NSPS).

(a) 1982 New source performance standards. Any new source as of November 19, 1982, subject to this subpart, must achieve the following new source performance standards and the revised requirements of § 423.13 of this part, published on [insert date of publication of final rule]:

(1) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(2) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

(3) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

NSPS	Pollutant or pollutant property	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

(4) The quantity of pollutants discharged in chemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of chemical metal cleaning wastes times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0
Copper, total	1.0	1.0
Iron, total	1.0	1.0

(5) [Reserved].

(6) The quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the bottom ash transport water times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

(7) There shall be no discharge of wastewater pollutants from fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(8)(i) For any plant with a total rated electric generating capacity of 25 or more megawatts, the quantity of pollutants discharged in once through cooling water from each discharge point shall not exceed the quantity determined by multiplying the flow of once through cooling water from each discharge point times the concentration listed in the following table:

Pollutant or pollutant property	NSPS
	Maximum concentrations (mg/l)
Total residual chlorine	0.20

(ii) Total residual chlorine may not be discharged from any single generating unit for more than two hours per day unless the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control. Simultaneous multi-unit chlorination is permitted.

(9)(i) For any plant with a total rated generating capacity of less than 25 megawatts, the quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

Pollutant or pollutant property	Maximum concentration (mg/l)	Average concentration (mg/l)
Free available chlorine	0.5	0.2

(ii) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10)(i) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed below:

Pollutant or pollutant property	Maximum concentration (mg/l)	Average concentration (mg/l)
Free available chlorine	0.5	0.2

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day concentration (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
The 126 priority pollutants (Appendix A) contained in chemicals added for cooling tower maintenance, except:	(1)	(1)
Chromium, total	0.2	0.2
Zinc, total	1.0	1.0

[1] No detectable amount.

(ii) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(iii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the limitations for the 126 priority pollutants in paragraph (a)(10)(i) of this section 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.

(11) Subject to the provisions of § 423.15(a)(12), the quantity or quality of pollutants or pollutant parameters discharged in coal pile runoff shall not exceed the limitations specified below:

Pollutant or pollutant property	NSPS
	For any time
TSS	not to exceed 50 mg/l.

(12) Any untreated overflow from facilities designed, constructed, and operated to treat the coal pile runoff which results from a 10 year, 24 hour rainfall event shall not be subject to the limitations in § 423.15(a)(11).

(13) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (a)(3) through (a)(10) of this section. Concentration limits shall be based on the concentrations specified in this section.

(14) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a)(1) through (a)(13) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

(The information collection requirements contained in paragraphs (a)(8)(ii), (a)(9)(ii), and (a)(10)(ii) were approved by the Office of Management and Budget under control number 2040–0040. The information collection requirements contained in paragraph (a)(10)(iii) were approved under control number 2040–0033.)

(b) 2014 New source performance standards. Any new source as of [insert date of publication of final rule], subject to this subpart, must achieve the following new source performance standards:

(1) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(2) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

(3) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

(4) The quantity of pollutants discharged in chemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of chemical metal cleaning wastes times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0
Copper, total	1.0	1.0
Iron, total	1.0	1.0

(5) The quantity of pollutants discharged in nonchemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of nonchemical metal cleaning wastes times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0
Copper, total	1.0	1.0
Iron, total	1.0	1.0

(6) There shall be no discharge of wastewater pollutants from bottom ash transport water. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(7) There shall be no discharge of wastewater pollutants from fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(8)(i) For any plant with a total rated electric generating capacity of 25 or more megawatts, the quantity of pollutants discharged in once through cooling water from each discharge point shall not exceed the quantity determined by multiplying the flow of once through cooling water from each discharge point times the concentration listed in the following table:

Pollutant or pollutant property	NSPS
	Maximum concentration (mg/l)
Total residual chlorine	0.20

(ii) Total residual chlorine may not be discharged from any single generating unit for more than two hours per day unless the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control. Simultaneous multi-unit chlorination is permitted.

(9)(i) For any plant with a total rated generating capacity of less than 25 megawatts, the quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum concentration (mg/l)	Average concentration (mg/l)
Free available chlorine	0.5	0.2

(ii) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10)(i) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed below:

Pollutant or pollutant property	NSPS	
	Maximum concentration (mg/l)	Average concentration (mg/l)
Free available chlorine	0.5	0.2

Pollutant or pollutant property	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
The 126 priority pollutants (Appendix A) contained in chemicals added for cooling tower maintenance, except:	[1]	[1]
Chromium, total	0.2	0.2
Zinc, total	1.0	1.0

[1] No detectable amount.

(ii) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(iii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the limitations for the 126 priority pollutants in paragraph (b)(10)(i) of this section 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.

(11) Subject to the provisions of § 423.15(b)(12), the quantity or quality of pollutants or pollutant parameters discharged in coal pile runoff shall not exceed the limitations specified below:

Pollutant or pollutant property	NSPS
	For any time
TSS	not to exceed 50 mg/l.

(12) Any untreated overflow from facilities designed, constructed, and operated to treat the coal pile runoff which results from a 10 year, 24 hour rainfall event shall not be subject to the limitations in § 423.15(b)(11).

(13)(i) The quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	8	6

Pollutant or pollutant property	NSPS	
	Maximum for any1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed
Mercury, total (ng/L)	242	119
Selenium, tota (ug/L)	16	10
Nitrate/nitrite as N (mg/L)	0.17	0.13

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(13)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the FGD wastewater in any other plant process or commingling of the FGD wastewater with any water or other process wastewater, except for any combustion residual leachate or any other FGD wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

(14) There shall be no discharge of wastewater pollutants from flue gas mercury control wastewater. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(15)(i) The quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day	Average ff daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	4	(1)
Mercury, total (ng/L)	1.76	1.29
Selenium, total (ug/L)	453	227
Total dissolved solids (mg/L)	38	22

[1] This regulation does not specify this type of limitation for this pollutant; however, permitting authorities may do so as appropriate.

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(15)(i) of this section, as applicable, by monitoring for all pollutants (except pH) prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with any water or other process wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

(16)(i) The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	8	6
Mercury, total (ng/L)	242	119

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(16)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the combustion residual leachate in any other plant process or commingling of the combustion residual leachate with any water or other process wastewater, except for any FGD wastewater or any other combustion residual leachate. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

(17) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (b)(3) through (b)(16) of this section. Concentration limits shall be based on the concentrations specified in this section.

(18) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b)(1) through (b)(16) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

■ 7. Section 423.16 is amended by adding paragraphs (c) and (e) through (i) to read as follows:

§ 423.16 Pretreatment standards for existing sources (PSES).

* * * * *

(c) Except for those discharges of nonchemical metal cleaning waste that are currently authorized without meeting standards for copper, the pollutants discharged in nonchemical metal cleaning wastes shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSES pretreatment standards
	Maximum for 1 day (mg/l)
Copper, total	1.0

* * * * *

(e)(1) For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, dischargers must meet the standards in this paragraph by a date determined by the control authority that is as soon as possible beginning July 1, 2017. These standards apply to pollutants in FGD wastewater generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Such effluent limitations shall not allow the quantity of pollutants in FGD wastewater to exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	8	6
Mercury, total (ng/L)	242	119
Selenium, total (ug/L)	16	10
Nitrate/nitrite as N (mg/L)	0.17	0.13

(2) A discharger must demonstrate compliance with the standards in paragraph (e)(1) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the FGD wastewater in any other plant process or commingling of the FGD wastewater with any water or other process wastewater, except for any combustion residual leachate or FGD wastewater. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

Note to (e): All proposed revisions to section 423.16(e) reflect proposed Option 4a, Option 3, and Option 3b (for units located a facilities with a total wet-scrubbed capacity of 2,000 MW or more), only. Under proposed Option 3a and Option 3b (for units located at facilities with a total wet-scrubbed capacity of less than 2,000 MW), POTWS would need to develop local limits to address the introduction of pollutants found in FGD wastewater by steam electric plants to the POTWs that cause pass through or interference, as specified in 40 CFR 403.5(c)(2).

(f) For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, there shall be no discharge of wastewater pollutants from fly ash transport water generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(g) For any electric generating unit with a total nameplate generating capacity of more than 400 megawatts and that is not an oil-fired unit, there shall be no discharge of wastewater pollutants from bottom ash transport water generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

Note to (g): All proposed revisions to section 423.16(g) reflect proposed Option 4a, only. For proposed Option 3, Option 3a, and Option 3b, the regulations would not specify a PSES for bottom ash transport water.

(h) For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, there shall be no discharge of wastewater pollutants from flue gas mercury control wastewater generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(i)(1) For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, dischargers must meet the standards in this paragraph by a date determined by the control authority that is as soon as possible beginning July 1, 2017. These standards apply to pollutants in gasification wastewater generated on or after a date determined by the control authority that is as soon as possible beginning July 1, 2017. Such effluent limitations shall not allow the quantity of pollutants in gasification wastewater to exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	4	(1)
Mercury, total (ng/L)	1.76	1.29
Selenium, total (ug/L)	453	227
Total dissolved solids (mg/L)	38	22

[1] This regulation does not specify this type of limitation for this pollutant; however, permitting authorities may do so as appropriate.

(2) A discharger must demonstrate compliance with the standards in paragraph (i)(1) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with any water or other process wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

■ 8. Section 423.17 is amended by revising paragraphs (a) and (b) to read as follows:

§ 423.17 Pretreatment standards for new sources (PSNS).

(a) 1982 Pretreatment standards for new sources. Except as provided in 40 CFR 403.7, any new source as of November 19, 1982, subject to this subpart, which introduces pollutants into a publicly owned treatment works must comply with 40 CFR part 403 and the following pretreatment standards for new sources (PSNS), and the revised requirements of § 423.16 of this part, published on [insert date of publication of final rule]:

(1) There shall be no discharge of polychlorinated biphenyl compounds such as those used for transformer fluid.

(2) The pollutants discharged in chemical metal cleaning wastes shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for any 1 day
Copper, total	1.0

(3) [Reserved].

(4)(i) The pollutants discharged in cooling tower blowdown shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for any time (mg/l)
The 126 priority pollutants (Appendix A) contained in chemicals added for cooling tower maintenance, except:	[1]
Chromium, total	0.2
Zinc, total	1.0

[1] No detectable amount.

(ii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the limitations for the 126 priority pollutants in paragraph (a)(4)(i) of this section 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.

(5) There shall be no discharge of wastewater pollutants from fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(b) 2014 Pretreatment standards for new sources. Except as provided in 40 CFR 403.7, any new source as of [insert date of publication of final rule], subject to this subpart, which introduces pollutants into a publicly owned treatment works must comply with 40 CFR part 403 and the following pretreatment standards for new sources (PSNS):

(1) There shall be no discharge of polychlorinated biphenyl compounds such as those used for transformer fluid.

(2) The pollutants discharged in chemical metal cleaning wastes shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for 1 day (mg/l)
Copper, total	1.0

(3) The pollutants discharged in nonchemical metal cleaning wastes shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for 1 day (mg/l)
Copper, total	1.0

(4)(i) The pollutants discharged in cooling tower blowdown shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for any time (mg/l)
The 126 priority pollutants (Appendix A) contained in chemicals added for cooling tower maintenance, except:	[1]
Chromium, total	0.2
Zinc, total	1.0

[1] No detectable amount.

(ii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the limitations for the 126 priority pollutants in paragraph (b)(4)(i) of this section 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.

(5) There shall be no discharge of wastewater pollutants from fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(6)(i) The quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

	Pollutant or pollutant property	PSNS
		Maximum for any 1 day
Arsenic, total (ug/L)	8	6
Mercury, total (ng/L)	242	119
Selenium, total (ug/L)	16	10
Nitrate/nitrite as N (mg/L)	0.17	0.13

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(6)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the FGD wastewater in any other plant process or commingling of the FGD wastewater with any water or other process wastewater, except for any combustion residual leachate or any other FGD wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

(7) There shall be no discharge of wastewater pollutants from flue gas mercury control wastewater. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(8) There shall be no discharge of wastewater pollutants from bottom ash transport water. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge prohibition in this paragraph.

(9)(i) The quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

	Pollutant or pollutant property	PSNS
		Maximum for any 1 day
Arsenic, total (ug/L)	4	(1)
Mercury, total (ng/L)	1.76	1.29
Selenium, total (ug/L)	453	227
Total dissolved solids (mg/L)	38	22

[1] This regulation does not specify this type of limitation for this pollutant; however, permitting authorities may do so as appropriate.

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(9)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the gasification wastewater in any other plant process or commingling of the gasification wastewater with any water or other process wastewater. Compliance with the standards must reflect results obtained from sufficiently sensitive analytical methods.

(10)(i) The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in the following table:

	Pollutant or pollutant property	PSNS
		Maximum for any 1 day
Arsenic, total (ug/L)	8	6
Mercury, total (ng/L)	242	119

(ii) A discharger must demonstrate compliance with the standards in paragraph (b)(10)(i) of this section, as applicable, by monitoring for all pollutants (except pH) at a point prior to use of the combustion residual leachate in any other plant process or commingling of the combustion residual leachate with any water or other process wastewater, except for any FGD wastewater or any other combustion residual leachate. Compliance with the effluent limitations must reflect results obtained from sufficiently sensitive analytical methods.

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