Regulation of Power Plant Wastewater Discharges: Summary of EPA's Proposed Rule

Claudia Copeland
Specialist in Resources and Environmental Policy

July 30, 2013

Congressional Research Service
7-5700
www.crs.gov
R43169

CRS Report for Congress
Prepared for Members and Committees of Congress
c11173008

Summary

To implement the Clean Water Act (CWA), the Environmental Protection Agency (EPA) issues effluent limitation guidelines (ELG), or technology-based standards, for industrial dischargers. These standards are implemented through permits issued by states or EPA to individual facilities. The current effluent limitations for the steam electric industry were issued in 1982.

Two factors have altered existing wastestreams or created new wastestreams at many power plants since promulgation of the current ELG. These factors are the development of new technologies for generating electric power, such as coal gasification, and, as a result of federal and state requirements, the widespread implementation of air pollution controls to reduce emissions of hazardous air pollutants and acid gases, such as flue gas desulfurization (scrubber) systems. While scrubbers dramatically reduce emissions of harmful pollutants into the air, some create a significant liquid waste stream. As a result, pollutant discharges from this industry to surface waters have increased in volume and total mass. EPA believes that many current CWA permits for power plants do not fully address potential water quality impacts of these discharges.

Based on studies of the industry and to settle litigation brought by environmental advocates, in April EPA issued a proposed rule to revise the steam electric ELG. In developing the proposal, EPA evaluated eight regulatory options and ultimately identified four preferred alternatives out of the eight for regulation of existing sources, without singling out a preference for any one of the four, and one preferred alternative for regulation of new sources. The options differ in the wastestreams to be controlled, the size of units controlled, and the types of controls. A total of 1,079 steam electric plants that burn fossil fuels and whose primary purpose is generating electricity are subject to the ELG. Only a subset of the 1,079 plants are likely to incur compliance costs as a result of the rule—only up to 277—because a large portion of the industry has already implemented processes or technologies that are the basis for EPA's proposed regulatory options. All of the plants that are expected to incur compliance costs are coal- or petroleum coke-fired. EPA estimates that the annual compliance costs for the proposed options range from $185 million to $954 million, costs that the agency believes are economically achievable and would have minimal effects on the electricity market, both nationally and regionally. The proposal also would reduce pollutant discharges by 470 million to 2.6 billion pounds and reduce water use by 50 billion to 103 billion gallons per year, depending on the option. Estimated costs exceed estimates of monetized benefits under all proposed options; however, the CWA does not require that the benefits of regulation exceed or even equal the costs.

A proposed EPA rule under the Resource Conservation and Recovery Act (RCRA) on managing coal combustion residuals (CCR) also relates to the CWA ELG proposal, because both statutes address coal ash that is generated by power plants and released to the environment. In 2010 EPA proposed options for a RCRA rule, not yet finalized, concerning CCR management. The scope of the CWA ELG and RCRA rule differ. While both address disposal of CCR in surface impoundments at power plants, only the RCRA rule would regulate disposal of CCRs in landfills. In the preamble to the proposed ELG, EPA said that it seeks to minimize the potential for overlap of the two statutes' requirements. Further, based on data that it has analyzed in connection with the proposed ELG, EPA states in the proposal that the agency's current thinking about coordinating the two rules provides strong support for concluding that regulation of CCRs under the RCRA rule as nonhazardous would be appropriate.

Public comments on the proposed ELG can be submitted until September 20, 2013. A number of issues already have been raised by stakeholders. Industry is concerned that EPA will set overly stringent standards that will be an economic burden on generators and may not be achievable. One issue concerns impacts of the proposal on small entities, including small businesses and small governmental jurisdictions, which own 18% of the plants subject to the proposal. Environmental advocates are urging EPA to adopt the most stringent of the regulatory options that it evaluated, in order to promote the most environmentally protective technologies for use by steam electric plants.

EPA rules affecting steam electric power plants have been scrutinized and criticized based on their stringency, feasibility, and projected compliance costs. Congressional interest has been evident in legislation that has been introduced to alter the direction and substance of some of EPA's regulatory actions and initiatives. To this point, discussion of the power plant ELG has centered on the administrative proceedings at EPA and has not drawn attention of lawmakers.

Contents

Tables

Appendixes

Contacts

Introduction

Since 2009, the Environmental Protection Agency (EPA) has proposed, promulgated, and is developing a number of regulations affecting the operation of the nation's steam electric power plants. Given the central role of electric power in the nation's economy, concerns have been raised about the cost and potential impact of many of these regulations.

Industry and environmental advocacy groups have been keenly interested in both the substance of these rules and schedules for their implementation. A particular issue has been whether the regulations, especially the cumulative impact of implementing multiple rules, will lead to retirement of a significant number of electric generating units, with negative effects on the reliability of the nation's power supply. All together, these rules have been characterized by critics as a regulatory "train wreck" that would impose excessive costs and lead to plant retirements that could threaten the adequacy of electricity capacity across the country. EPA and many other analysts maintain that this will not be the case.

Much of the criticism addressed to EPA's actions has concerned Clean Air Act rules, but Clean Water Act (CWA) rules have been part of the discussion, as well, such as a pending rule to regulate cooling water intake structures at power plants and some industrial sources.[1] The most recent major rule affecting power plants that EPA has proposed concerns limits on discharges of wastewater, and it is the subject of this report. It is a complex rule, involving limits on seven pollutant wastestreams, that would update standards that were issued more than 30 years ago, which do not reflect today's power plant technology.

Background

The 1972 CWA established a comprehensive program to "restore and maintain the chemical, physical and biological integrity of the Nation's waters." To implement the act, EPA was directed to issue effluent limitation guidelines and standards, or technology-based regulations, for industrial dischargers. The effluent guidelines (ELG) are to reflect pollutant reductions that can be achieved by categories or subcategories of industrial point sources using technologies that represent appropriate levels of control. Since 1972, EPA has promulgated effluent limitation guidelines for 57 industrial categories, including for the steam electric power industry.

For point sources that introduce pollutants directly into U.S. waters (termed direct dischargers), limits on specific pollutants set in effluent guidelines are implemented through National Pollutant Discharge Elimination System (NPDES) permits that are issued by EPA or states. For sources that discharge to publicly owned treatment works, or POTWs, (termed indirect dischargers), EPA promulgates pretreatment standards that apply to those sources and are enforced by POTWs, and state and federal authorities. The guidelines and standards apply to direct and indirect discharges of conventional pollutants;[2] toxic pollutants, including toxic metals and toxic organic pollutants;

[1] For information, see CRS Report R41786, *Cooling Water Intake Structures: Summary of EPA's Proposed Rule*, by Claudia Copeland.

[2] CWA §304(a)(4) designates the following as conventional pollutants: biochemical oxygen demand (BOD5), total suspended solids, fecal coliform, pH, and any additional pollutants defined by EPA as conventional; EPA designated oil and grease as an additional conventional pollutant in 1979.

and non-conventional pollutants, which are all other pollutants that are not categorized as conventional or toxic (e.g., ammonia-N, phosphorus, and total dissolved solids).

The CWA established several different kinds of effluent limitations, four for new and existing direct dischargers and two for new and existing indirect dischargers. Effluent limitations are based on performance of specific technologies, but regulations do not require use of a specific control technology. In establishing effluent limitations, EPA considers the cost and/or economic achievability of the controls. The economic test differs based on the level of control specified in the ELG.

- Best Practicable Control Technology Currently Available (BPT)—BPT limitations generally are based on the average of the best existing performance of plants within the industry or subcategory. In specifying BPT, EPA considers the total cost of applying the control technology in relation to the effluent reduction benefits, as well as the age of the equipment and facilities, processes employed, and other factors. BPT limitations can cover conventional, toxic, and non-conventional pollutant discharges.
- Best Available Technology Economically Achievable (BAT)—BAT limitations generally represent the best existing performance in the industrial category or subcategory. BAT is the principal national means of controlling toxic and nonconventional pollutant discharges. Factors considered in assessing BAT include the cost of achieving BAT effluent reductions, processes employed, and other factors. The EPA Administrator has considerable discretion in assigning the weight accorded to these factors. BAT limitations may be based on effluent reductions attainable through changes in a facility's processes and operations.
- Best Conventional Pollutant Control Technology (BCT)—BCT is not an additional limitation, but it replaces BAT for the control of conventional pollutant discharges from existing industrial sources. The statute specifies factors to be assessed in determining BCT, including a two-part "cost reasonableness" test.
- New Source Performance Standards (NSPS)—NSPS are based on the best available demonstrated control technology (BADCT) and represent the most stringent control attainable through the application of technology. New plants have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.
- Pretreatment Standards for Existing Sources (PSES)—PSES are designed to control the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of a POTW. PSES standards are analogous to BAT for direct dischargers.
- Pretreatment Standards for New Sources (PSNS)—Like PSES, PSNS are designed to control the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of a POTW. EPA considers the same factors in promulgating PSNS that it does in promulgating NSPS.

The requirements of the statute embody the concept that, over time, industrial sources will achieve greater pollutant removal by employing progressively more stringent technologies. Thus, the 1972 law required sources to achieve effluent limitations based on BPT by July 1, 1977, and effluent limitations based on BAT by July 1, 1983 (in 1987 Congress modified the date to achieve BAT to March 31, 1989). New sources are expected to comply with applicable effluent limitations when they commence operation.

Steam Electric Industry ELG

EPA initially promulgated effluent limitation guidelines for the steam electric industry in 1974 and issued revised standards in 1982.[3] The current rules apply to about 1,100 nuclear- and fossil-fueled steam electric power plants nationwide, 495 of which are coal-fired.

Under the CWA, EPA has a duty to review existing effluent limitation guidelines at least every five years and, if appropriate, revise them. EPA had been studying the ELG for the steam electric power generating category since the mid-1990s and on several occasions indicated that a preliminary study of discharges from this category was necessary. In particular, during the 2005 review of the existing effluent guidelines for all categories, EPA identified the rules governing the steam electric power point source category for possible revision, based in part on data showing that the industry ranked high in discharges of toxic and nonconventional pollutants.

Broadly speaking, two factors have altered existing wastestreams or created new wastestreams at many power plants since promulgation of the current power plant ELG. These factors are the development of new technologies for generating electric power, such as coal gasification, and, as a result of federal and state requirements, the widespread implementation of air pollution controls to reduce emissions of hazardous air pollutants and acid gases (e.g., flue gas desulfurization [FGD], selective catalytic reduction [SCR], and flue gas mercury controls [FGMC]). In particular, the use of wet FGD systems (the kind that generate liquid discharges) to control sulfur dioxide air emissions has increased significantly since the last revision of the ELG in 1982. Consequently, each year the pollutant discharges from this industry are increasing in volume and total mass and account for 50%-60% of all toxic pollutants discharged into surface waters by all industrial categories currently regulated under the CWA, according to EPA. The main pollutants of concern for these discharges include metals (mercury, arsenic, selenium), nitrogen, and total dissolved solids (TDS).

EPA initiated a study, completed in 2009,[4] which found that the current regulations do not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades, specifically the increase of flue gas desulfurization (FGD) systems, or scrubbers, at coal-fired power plants to control air pollution. According to EPA, as of June 2008, 30% of coal-fired power plants were using FGD systems to control sulfur dioxide emissions from the flue gas generated in the plants' boilers and prevent buildup of certain corrosive constituents such as chlorides, and by 2025, nearly 80% of coal-fired generating capacity is expected to employ FGD systems. While scrubbers dramatically reduce emissions of harmful pollutants into the air, some create a significant liquid waste stream (especially wet scrubbers). In addition, discharges from coal combustion waste (CCW) surface impoundments at steam electric power plants have a potential to degrade water quality. EPA believes that many current CWA permits for power plants do not fully address potential water

[3] 40 CFR Part 423.

[4] U.S. Environmental Protection Agency, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report*, EPA 821-R-09-008, October 2009.

quality impacts of these discharges through appropriate pollutant limits and monitoring and reporting requirements. In addition, EPA identified several wastestreams that are relatively new to the industry (e.g., carbon capture wastewater) and others for which there is little characterization data (e.g., gasification wastewater).

In 2009, environmental groups sued EPA to compel the agency to commit to a schedule for issuing revised guidelines for this industry. Pursuant to a November 8, 2010, consent decree that it entered into with these litigants, EPA agreed to propose the revised power plant ELG by July 23, 2012, and to finalize the rule by January 31, 2014. These dates were subsequently modified and required EPA to propose revised effluent limitations by April 19, 2013, and to finalize the rule by May 22, 2014.[5] Pursuant to that agreement, EPA proposed revised standards on April 19. The proposal was published in the *Federal Register* on June 7. Public comments on the proposal will be accepted until September 20, 2013.[6]

Overview of Sources Regulated under the Proposed Rule

The proposed ELG applies to two broad categories of firms in the electric power industry, electric utilities and non-industrial non-utilities. Both categories produce electric power for distribution and/or sale.[7] Non-industrial non-utilities (which generally operate in a non-regulated pricing environment) account for 49% of plants but represent only 30% of total U.S. generating capacity. Utilities, which generally operate in a rate regulation framework, consist of investor owned utilities (2,776 plants that account for about 50% of all U.S. electric generating capacity); publicly owned utilities (federal, state, and municipalities operate a total of 1,040 plants, but they represent only 13% of U.S. electric generation capacity); and rural electric cooperatives (they operate 240 plants, representing 4% of U.S. generating capacity).

The number of steam electric plants subject to the ELG is 1,079 (units that do not burn fossil fuels or plants with a primary purpose other than generating electricity are not subject to the ELG). These plants operate approximately 1,210 generating units with total capacity of 741,000 megawatts (MW) of electricity. The 1,079 steam electric plants represent about 19% of the total

---

[5] Consent decree in Defenders of Wildlife and Sierra Club v. EPA, Case No. 10-cv-1915, D.C. D.C., December 12, 2012. Electric utility industry groups, which were not parties to the consent decree, attempted to challenge the dates in the consent decree, but a federal appeals court ruled that the industry lacked standing to intervene in the consent decree that compelled EPA to follow a timeline for the rulemaking. Defenders of Wildlife v. EPA, D.C. Cir., No. 12-5122, April 23, 2013.

[6] U.S. Environmental Protection Agency, "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule," 78 *Federal Register* 34432-34543, June 7, 2013. At the same time, EPA also published several supporting documents in connection with the proposed rule. *Technical Development document for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Document No. EPA-821-R-13-002, April 2013, hereinafter, TDD; *Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Document No. EPA-821-R-13-003, April 2013; *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, April 2013, hereinafter, Benefit-Cost; and *Regulatory Impact Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Document No. EPA-821-R-13-005, April 2013, hereinafter, RIA. See http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm. Extension of the public comment period from August 6, 2013, to September 20, 2013, was published at 78 *Federal Register* 41907, July 12, 2013.

[7] A third category in the industry, industrial non-utilities, is not primarily engaged in producing electricity for distribution and/or sale. Plants in this category are not subject to the ELG.

number of plants in the power generation sector, but represent about 70% of the national total electric generating capacity. The vast majority (93%) burn at least some amount of either coal or gas, and 74% of the steam electric units in the industry burn more than one type of fuel (e.g., coal and oil, coal and gas). Coal- and petroleum-coke fired plants comprise 44% of the 1,079 plants subject to the proposed ELG. Coal is the most common primary fuel type for stand-alone steam turbines, while gas is the primary fuel for nearly all combined cycle systems. Oil-fired units account for about 5% only. Nuclear plants account for about 4.5% of generating units.[8]

The largest capacity plants (>500 MW) comprise 63% of all steam electric power plants and 92% of the steam electric generating capacity for all plants regulated by the ELG. Most steam electric power plants are either gas- or coal-fired and have a generating capacity greater than 500 MW. Only a few plants (3%) have a capacity greater than 2,500 MW. The smallest plants, under 100MW, comprise about 10% of plants and provide less than 1% of generating capacity.[9]

Overview of the Current and Proposed Rules

The 1982 pollutant discharge limitations apply to 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,[10] and material storage and construction site runoff (including coal pile runoff). The current ELG contains standards for BPT, BAT, and PSES for existing sources and NSPS and PSNS for new sources.

- Current BPT regulations for the steam electric industry contain numeric limits to control total suspended solids (TSS) and oil and grease in low volume wastes, and fly ash and bottom ash transport water. They include numeric limits to control TSS, oil and grease, copper, and iron in chemical metal cleaning wastes; free available chlorine in cooling water discharges; and TSS in coal pile runoff.
- Current BAT regulations contain numeric limits to control total residual chlorine in once-through cooling water discharges; free available chlorine and toxic pollutants (generally requiring zero discharge) in cooling tower blowdown; and copper and iron in chemical metal cleaning wastes.
- Current NSPS regulations contain numeric limits to control TSS and oil and grease in low volume wastes; TSS, oil and grease, copper, and iron in chemical metal cleaning wastes; TSS and oil and grease discharges from bottom ash transport water; zero discharge limits on fly ash transport water; chlorine limitations on cooling water discharges; and TSS in coal pile runoff.
- Current PSES standards contain numeric limits on copper in chemical metal cleaning wastes; and toxic pollutants in cooling tower blowdown. Current PSNS standards contain numeric limits on copper in chemical metal cleaning wastes; and on chromium and zinc in cooling tower blowdown.

[8] TDD, p. 4-17, Table 4-3.

[9] TDD, p. 4-18, Table 4-4.

[10] Under the current ELG, low volume wastes mean wastewater from all sources except those for which specific limitations are included, such as wastewater from boiler blowdown or floor drains.

The April 2013 proposal would modify the BAT, NSPS, PSES, and PSNS requirements for existing and new sources.[11] The proposed rule would establish new or additional requirements for seven processes utilized by steam electric power plants and byproducts of those processes. EPA has found that these wastestreams, some of which were not evaluated or were evaluated to only a limited extent during the previous rulemakings, contain pollutants in concentrations and mass loadings that cause documented environmental impacts. EPA also has found that treatment technologies to reduce or eliminate the pollutant discharges are available, economically achievable, and have acceptable non-water quality environmental impacts.

In developing the power plant ELG proposal, EPA evaluated eight regulatory options[12] and ultimately identified four preferred alternatives out of the eight for regulation of existing discharges (referred to as Options 3a, 3b, 3, and 4a in the proposed rule) and one preferred alternative for regulation of new sources (Option 4). The preferred options are summarized in **Table 1**. In the proposed rule, EPA does not express a preference for any one of the four options for existing sources that discharge directly to surface water. The options differ in the wastestreams controlled by the regulation, the size of the units controlled, and the types of controls. Some of the preferred alternatives would establish more environmentally protective BAT requirements for discharges from two of the wastestreams from existing sources (i.e., FGD wastewater and bottom ash transport water). The four options incorporate differences that reflect stringency and cost. Proposed Option 3a is the least stringent and would be less costly to implement than the others, while Option 4a is the most stringent, with greater pollutant removal, and would be more costly to implement than the others. Options 3b and 3 are between Options 3a and 4a in stringency, pollutant removal, and cost.

The proposed ELG addresses 46 pollutants of concern that are known to be discharged by steam electric generating units and their processes, including several metals (arsenic, mercury, selenium), various non-metal compounds (chloride, fluoride, sulfate), nutrients, and conventional pollutants (oil & grease, biological oxygen demand (BOD)). The number of pollutants discharged by each of the regulated wastestreams varies. For example, FGD wastewater contains 34 pollutants of concern, fly ash transport water contains 24 pollutants of concern, and gasification wastewater contains 19 pollutants of concern.

[11] EPA is not proposing to revise the BPT effluent guidelines, because the same wastestreams would be controlled at the proposed BAT and NSPS levels of control.

[12] The eight regulatory options are shown in 78 *Federal Register* 34458, Table VII-1.

Table 1. Regulatory Options under Proposed Power Plant ELG

Technology basis for the main BAT/NSPS/PSES/PSNS regulatory options (see Notes)

Wastestreams	Option 3a (existing facilities)	Option 3b (existing facilities)	Option 3 (existing facilities)	Option 4a (existing facilities)	Option 4 (new sources)[a]
FGD wastewater	Best Professional Judgment (BPJ, i.e., site-specific determination)	Technology basis: chemical precipitation + biological treatment for plants with total wet-scrubbed capacity of 2,000 MW or greater (numeric limits for mercury, arsenic, selenium, nitrate-nitrite); for smaller units, BPJ	Technology basis: chemical precipitation + biological treatment (numeric limits for mercury, arsenic, selenium, nitrate-nitrite)	Technology basis: chemical precipitation + biological treatment (numeric limits for mercury, arsenic, selenium, nitrate-nitrite)	Technology basis: chemical precipitation + biological treatment (numeric limits for mercury, arsenic, selenium, nitrate-nitrite)
Fly ash transport water	Technology basis: dry handling (zero discharge)	Technology basis: dry handling (zero discharge)	Technology basis: dry handling (zero discharge)	Technology basis: dry handling (zero discharge)	Technology basis: dry handling (zero discharge, same as existing NSPS)
Bottom ash transport water	Technology basis: impoundment (same as existing BPT); PSES: no pretreatment standards proposed	Technology basis: impoundment (same as existing BPT); PSES: no pretreatment standards proposed	Technology basis: impoundment (same as existing BPT); PSES: no pretreatment standards proposed	Technology basis for units >400 MW: dry handling/closed loop (zero discharge); Technology basis for units <400 MW: impoundment (same as existing BPT); PSES: no pretreatment standards proposed for EGUs 400 MW or less; for larger units, zero discharge	Technology basis: dry handling/closed loop (zero discharge)
Combustion residual leachate from landfills or surface impoundments	Technology basis: impoundment (same as existing BPT)	Technology basis: impoundment (same as existing BPT)	Technology basis: impoundment (same as existing BPT)	Technology basis: impoundment (same as existing BPT)	Technology basis: chemical precipitation (zero discharge) (numeric limits for mercury and arsenic)

Wastestreams	Option 3a (existing facilities)	Option 3b (existing facilities)	Option 3 (existing facilities)	Option 4a (existing facilities)	Option 4 (new sources)[a]
Flue gas mercury control system wastewater	Technology basis: dry handling (zero discharge)	Technology basis: dry handling (zero discharge)	Technology basis: dry handling (zero discharge)	Technology basis: dry handling (zero discharge)	Technology basis: dry handling (zero discharge)
Gasification wastewater	Technology basis: vapor-compression evaporation (numeric limits for mercury, arsenic, selenium, TDS)	Technology basis: vapor-compression evaporation (numeric limits for mercury, arsenic, selenium, TDS)	Technology basis: vapor-compression evaporation (numeric limits for mercury, arsenic, selenium, TDS)	Technology basis: vapor-compression evaporation (numeric limits for mercury, arsenic, selenium, TDS)	Technology basis: vapor-compression evaporation (numeric limits for mercury, arsenic, selenium, TDS)
Nonchemical metal cleaning wastes	Technology basis: chemical precipitation (numeric limits for copper and iron[c]); PSES: numeric limits for copper	Technology basis: chemical precipitation (numeric limits for copper and iron[c]); PSES: numeric limits for copper	Technology basis: chemical precipitation (numeric limits for copper and iron[c]); PSES: numeric limits for copper	Technology basis: chemical precipitation (numeric limits for copper and iron[c]); PSES: numeric limits for copper	Technology basis: chemical precipitation NSPS: Numeric limits for TSS, oil and grease, copper, and iron; PSNS: numeric limits for copper

Source: Compiled by CRS from U.S. Environmental Protection Agency, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Proposed rule, 78 *Federal Register* 34432-34543, June 7, 2013.

Notes: Under Options 3a, 3b, 3, and 4a, for existing oil-fired generating units and generating units 50 MW or smaller, BAT=existing BPT for all wastestreams.

a. BPT = Best Practicable Technology; BAT = Best Available Technology; PSES = Pretreatment Standard for Existing Sources; PSNS = Pretreatment Standard for New Sources; NSPS = New Source Performance Standard

b. Under the proposed ELG, PSNS=NSPS, except PSNS would not include numeric limits for TSS, oil and grease, or iron in discharges of nonchemical metal cleaning wastes.

c. Existing discharges of nonchemical metal cleaning wastes that are currently authorized without iron and copper limits would be exempt from new copper and iron BAT limitations. For these discharges, BAT=BPT limits applicable to low volume wastes.

EPA also is proposing provisions in the rule that would prevent facilities from circumventing the effluent limitation standards and guidelines. These anti-circumvention provisions would prevent facilities from mixing wastewater from one of the more highly regulated waste streams with another that would be subject to a lower standard and disposing of the waste under the less stringent limit. EPA is seeking comment on whether these provisions would discourage water reuse. Further, EPA would prohibit facilities from using insufficiently sensitive analytical methods for compliance monitoring purposes, thus potentially masking the presence of a pollutant in the discharge, when EPA-approved methods are available that could detect exceedance of the effluent limit.

Proposed Revisions for Direct Discharges

As described above, EPA proposed four alternatives for *existing* direct discharge sources, without singling out a preference for any of the four. Under one preferred alternative for existing sources (referred to as Option 3a), the proposed rule would establish BAT that include:

- Zero discharge limit for all pollutants in fly ash transport water and wastewater from flue gas mercury control systems;
- Numeric 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 cleaning wastes; and
- Effluent limits for bottom ash transport water and combustion residual leachate from landfills and surface impoundments that are equal to the current BPT effluent limits for these discharges.

Option 3a could be considered the baseline preferred option. Each of the other three preferred options for existing direct discharging sources builds on the one that precedes it and includes more stringent requirements.

Under a second preferred alternative for BAT for existing sources (Option 3b), the proposed rule would establish numeric effluent limits for mercury, selenium, and nitrate-nitrite in discharges of FGD wastewater from steam electric facilities with a total plant-level wet scrubbed capacity of 2,000 MW or greater. For steam electric plants below that threshold, FGD wastewater controls would be determined according to the Best Professional Judgment (BPJ) of the permit writer. All other proposed Option 3b requirements are identical to the proposed Option 3a requirements.

Under a third preferred alternative for BAT for existing sources (Option 3), the proposed rule is the same as Option 3b, except that the threshold for numeric limits for FGD wastewater controls would be 50 MW or smaller (that is, small generating units would be subject to BPJ determinations).

Finally, under a fourth preferred alternative for BAT for existing sources (Option 4a), the proposed requirements would be identical to those under Option 3, except for pollutants in bottom ash transport water. Under this option, the proposed rule would establish zero discharge limits for this wastestream, except for generating units with a nameplate capacity of 400 MW or less. For these smaller units, the proposed rule would set BAT equal to BPT for discharges of pollutants in bottom ash transport water (i.e., with numeric effluent limits for TSS and oil and grease).

Under all four preferred options for existing sources, EPA is proposing to establish BAT effluent limits for existing oil-fired generating units and small electric generating units (EGUs), that is, those 50 MW or smaller, that differ from the effluent limits for all other generating units. For these facilities, EPA is proposing to set BAT effluent limits equal to existing BPT effluent limits for all of the wastestreams addressed by the proposed rule. According to EPA, 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 ELG. Likewise, small EGUs 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, while the amount of pollutants collectively discharged by small units is a small portion of pollutants discharged collectively by all power plants.

For all generating units that are *new* sources and will discharge directly to surface waters (including oil-fired and small generating units), EPA's proposal is the most stringent regulatory option, Option 4 (see **Table 1**). 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 NSPS zero discharge standard for all pollutants in fly ash transport water;
- 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.

Proposed Revisions for Indirect Discharges to Publicly Owned Treatment Works (POTWs)

As described above, EPA prescribes pretreatment standards for existing sources (PSES) and new sources (PSNS) that discharge wastewater to publicly owned treatment works (POTWs), rather than fully treating their wastes and discharging directly to nearby surface waters. Pretreatment standards are intended to prevent the discharge of pollutants that would pass through, interfere with, or otherwise be incompatible with the operation of the POTW.

For discharges from *existing* sources to POTWs (PSES), EPA is proposing to establish PSES that are equal to the proposed BAT for existing direct dischargers under each of the four preferred options with the following exceptions:

- Numeric standards for discharges of nonchemical metal cleaning wastes would be established only for copper;
- EPA is generally not proposing to establish pretreatment standards for discharges of bottom ash transport water under any of the options, except under Option 4a, which would include pretreatment standards for this wastestream for generating units with a nameplate capacity of 400 MW or greater; and
- For existing oil-fired and small generating units (i.e., 50MW or smaller), EPA is proposing only pretreatment standards for nonchemical metal cleaning wastes.

For discharges from *new* sources to POTWs (PSNS), Option 4 is EPA's preferred option. This option is equal to the proposed NSPS, described above, except that the proposed PSNS would not include numeric standards for TSS, oil and grease, or iron in discharges of nonchemical metal cleaning wastes.[13]

EPA believes that the technology for Option 4 is available and is economically achievable for new indirect discharging sources, because the costs to install technologies at new units are typically less than the costs to retrofit existing units. EPA did not propose Option 4 as a preferred option for existing sources that discharge to POTWs because of the projected compliance costs associated with certain of its requirements (i.e., zero discharge requirements for bottom ash for units equal to or below 400 MW). 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 pollution controls are installed at the time the new source is constructed.

The **Appendix** to this report provides more detailed description of the seven wastestreams that would be regulated under EPA's proposal.

Relationship of the Proposed ELG to Other EPA Rules and Rulemakings

The steam electric power sector is a source of significant pollutant emissions and discharges to the environment,[14] and thus is subject to pollution control requirements under a number of federal environmental laws. In the preamble to the proposed rule and documents supporting it, EPA discusses how the proposed ELG relates to several existing EPA rules and pending rulemakings. These include regulations under the Clean Air Act (such as Mercury and Air Toxics Standards promulgated in 2012)[15] and other provisions of the CWA (such as the pending cooling water intake rule).[16] A proposed rule under the Resource Conservation and Recovery Act (RCRA)[17] on managing coal combustion residuals (CCR) also relates to the CWA ELG proposal, because both statutes address coal combustion waste such as coal ash that is generated by electric utilities and independent power producers and released to the environment.

The Proposed ELG and the CCR Rulemaking under RCRA

Disposal of CCR onsite at individual power plants may involve decades-long accumulation of tons of dry ash (in a landfill) or wet ash slurry (in a surface impoundment) deposited at the site. In

13 According to EPA, this is because the agency generally does not establish pretreatment standards for conventional pollutants, such as TSS and oil and grease, because, although POTWs are not designed to treat most toxic pollutants, they are designed to treat conventional pollutants.

14 EPA estimates that the total pollutant loadings associated with combustion wastewater discharges from steam electric power plants alone contribute 50%-60% of the reported toxic-weighted pollutant loadings of the combined discharges of all industrial categories currently regulated in the United States. 78 *Federal Register* 34505.

15 For information, see CRS Report R42144, *EPA's Utility MACT: Will the Lights Go Out?*, by James E. McCarthy.

16 For information, see CRS Report R41786, *Cooling Water Intake Structures: Summary of EPA's Proposed Rule*, by Claudia Copeland.

17 RCRA established the federal program for regulating solid and hazardous waste management (42 U.S.C. 6901 et seq.). For information, see CRS Report RL30798, *Environmental Laws: Summaries of Major Statutes Administered by the Environmental Protection Agency*, coordinated by David M. Bearden.

December 2008, national attention was turned to risks associated with managing such large volumes of waste when a breach in a surface impoundment pond at the Tennessee Valley Authority's Kingston, TN, plant released 1.1 billion gallons of coal fly ash slurry that damaged or destroyed homes and property. Beyond the potential for a sudden, catastrophic release from a surface impoundment, a more common threat associated with CCR management is the leaching of contaminants commonly present in the waste, primarily heavy metals, resulting in surface or groundwater contamination. This risk is particularly high at unlined surface impoundments, which are in common use today.

The Kingston release also brought attention to how the waste is managed and regulated. CCR management is largely exempt from federal regulations and is regulated by individual states. According to EPA, national standards to regulate CCR are needed because of inconsistencies and deficiencies in state regulatory programs. To establish a national standard necessary to address potential threats of improper CCR management to human health and the environment, in June 2010, EPA proposed two regulatory options under RCRA. Under the first option, EPA would draw on its existing RCRA Subtitle C authority to list a waste as hazardous and to regulate it through authorized state programs. The second option would establish national criteria applicable to landfills and surface impoundments under RCRA's Subtitle D non-hazardous solid waste requirements. Under Subtitle D, EPA does not have the authority to implement or enforce its proposed requirements. Instead, EPA would rely on states to operate approved regulatory programs or citizen suits to enforce the new standards. However, the possible listing of CCR as hazardous waste has been very controversial. EPA is still evaluating public comments on the 2010 proposal and has not indicated when a final CCR rule might be issued.[18]

The scope of the CWA ELG and RCRA rule differ. While both address disposal of CCR in surface impoundments at power plants, only the RCRA rule would regulate disposal of CCRs in landfills. In the preamble to the proposed ELG, EPA said that it seeks to effectively coordinate any final RCRA and CWA requirements to ensure that the rules under the two statutes work together while minimizing the potential for overlap, especially concerning surface impoundments. The agency is considering two means of integrating the rules: (1) coordinating the design of any final CCR requirements and (2) coordinating the timing and implementation of requirements. For example, one possible consequence of the requirements in the ELG is that many power plants will convert from wet to dry fly ash handling systems and will no longer send such wastes to surface impoundments. If this occurs, it might affect the time frames for closure of impoundments under a RCRA rule, according to EPA. The agency anticipates that a facility would be able to determine whether any changes to its operations are needed to comply with the CWA ELG before it would be required to decide whether to retrofit or close surface impoundments to comply with any CCR rule. This likely effort to coordinate the two rules would effectively subordinate implementation of the RCRA rule to that of the CWA rule.

Further, based on data that EPA has analyzed in connection with the proposed ELG rule, the agency now believes that risks addressed in the RCRA CCR rule are much lower than previously estimated. While no final determination has been made, the newer data in combination with the

[18] For information on the CCR rulemaking, see CRS Report R43003, *Analysis of Recent Proposals to Amend the Resource Conservation and Recovery Act (RCRA) to Create a Coal Combustion Residuals Permit Program*, by Linda Luther, James E. McCarthy, and James D. Werner.

ELG requirements "could provide strong support" for concluding that regulation of CCR as nonhazardous waste would be appropriate.[19]

The ELG proposal does not contain any explicit decision or altered proposal with respect to the CCR rulemaking, but it describes the agency's "current thinking" about coordinating the two rules. In addition, the ELG proposal does incorporate some elements of the pending RCRA rule, as described next.

BMPS for CCR Impoundments

CWA Section 304(e) authorizes EPA to supplement effluent limitation guidelines with Best Management Practices (BMPs) for toxic or hazardous pollutants in order to control plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage that is ancillary to the regulated industrial process and may contribute significant amounts of pollutants to U.S. waters. In the ELG proposal, EPA said that it is considering using this authority to establish BMP requirements to address impoundment construction, operation, and maintenance. EPA explains that the BMPs under consideration are similar to structural integrity and corrective action requirements that EPA has proposed in the RCRA rulemaking that addresses CCR.[20] In the CWA proposal, EPA says that the BMP provisions being considered in both the ELG and CCR rulemakings, such as requiring that impoundment inspections be conducted weekly by a qualified person, are critical to ensure that owners and operators of impoundments become aware of structural stability problems before they occur. If included in the ELG rule, these BMPs would become conditions to be included in CWA permits, along with numeric limits and other requirements in that rule, thus utilizing the CWA to accomplish a portion of the agency's objectives in the CCR regulatory proposal, which is not yet final.

EPA proposes that the CWA rule also include BMP provisions for CCR surface impoundments similar to those for coal slurry impoundments at coal mines promulgated by the Mine Safety and Health Administration (MSHA).[21] These provisions in the proposed ELG would require facilities using CCR impoundments to submit to the CWA permitting authority (EPA or an authorized state) plans for design, construction, and maintenance of existing impoundments, as well as closure plans. They also would require periodic inspection and annual certification of the construction, operation, and maintenance of the impoundment.

Timing of New Requirements

EPA expects to promulgate a final ELG rule in 2014. The agency believes that providing a window of time for facilities to raise capital, plan and design systems, and construct and test equipment will enable installation of technology during planned shutdown or maintenance periods. Further, EPA anticipates that for many plants, changes to FGD wastewater treatment systems, fly ash and bottom ash systems, and leachate treatment systems would constitute major system modifications requiring several years to accomplish. Under all of the preferred regulatory options, EPA proposes that BAT limitations for existing sources (those that would establish

---

[19] 78 *Federal Register* 34442.

[20] The BMP provisions in the ELG proposal do not include closure requirements that were proposed as part of the CCR rulemaking.

[21] 30 CFR 77.216.

requirements more stringent than existing BPT requirements) would apply to discharges generated on or after the date established by the permitting authority that is as soon as possible within the next permitting cycle after July 1, 2017. Under EPA's proposed approach, all steam electric facilities will have the proposed BAT limitations applied to their permits no later than July 1, 2022, approximately eight years from the anticipated date of promulgation of a final regulation. Plants are assumed to implement the control technologies within the five-year window of 2017-2021, occurring roughly evenly in each of those years.

For those parts of the rule where EPA is proposing BAT limits equivalent to current BPT limits (e.g., combustion residual leachate), requirements would be applicable on the effective date of the final rule, since existing facilities presumably are already meeting these limits. Also, new NSPS and PSNS requirements (for new sources) would be applicable on the effective date of the rule.

Voluntary Incentive Program Allowing Additional Time for Compliance

EPA also is considering establishing a voluntary incentive program that would provide more time for existing plants to implement BAT requirements if they adopt additional process changes and controls, beyond those in the preferred regulatory options that EPA might finalize. In exchange for additional compliance time, power plants would ultimately be agreeing to adopt discharge limits more stringent than in the proposed rule.

This voluntary program would establish two levels of advanced technology performance requirements. First, power plants would be granted two additional years for compliance if they also dewater, close, and cap all CCR surface impoundments at the facility (except for those impoundments containing only combustion residual leachate). This would mean that the facility would be required to comply for discharges generated on or after the date established by the permitting authority that is as soon as possible within the next permitting cycle after July 1, 2019, rather than July 1, 2017.

Second, power plants would be granted five additional years if they eliminate the discharge of all process wastewater to surface waters, with the exception of cooling water discharges, by reducing the amount of wastewater generated and preferentially using recycled wastewater to meet water supply demands. This would mean that the facility would be required to comply with the rules for discharges generated on or after the date established by the permitting authority that is as soon as possible within the next permitting cycle after July 1, 2022, rather than July 1, 2017. The primary objective of this program would be to encourage individual power plants to install advanced pollution prevention technologies or make process changes to reduce toxic pollutant discharges beyond limits set by the proposed rule. Power plants would have until July 1, 2017, to commit to the program and submit a plan for achieving the additional pollutant reductions.

Costs and Benefits of the Proposal

Compliance Costs of the Proposed ELG

EPA estimates that, of the 1,079 total steam electric plants subject to the proposed ELG, only a subset are likely to incur compliance costs as a result of the rule. EPA identified up to 277 steam electric plants[22] that may incur non-zero compliance costs under one or more regulatory options, based on their wastestreams and existing control technologies (these plants generate and discharge FGD wastewater, fly ash transport water, bottom ash transport water, and/or combustion residual landfill leachate).[23] This is because a portion of the industry has already implemented processes or technologies that are the basis for the proposed regulatory options. Thus, these plants would incur no costs, or lower costs than if the processes or technologies had not already been implemented.[24] All of the plants that are expected to incur compliance costs are coal- or petroleum coke-fired.

Costs consist of capital and other one-time costs, plus annual fixed and variable O&M costs. Other fixed O&M costs will be incurred periodically, for example, every 3, 5, 6, and 10 years. Major compliance costs of the regulatory options are associated with controls on FGD and bottom ash transport wastewater (under some options) and fly ash transport wastewater. EPA determined that there would be no costs associated with gasification wastewater, flue gas mercury control wastewater, and nonchemical metal cleaning wastes because the proposed ELG is either setting requirements that are already in place based on BPT or because the proposed BAT technology is already the current industry standard.

In the Regulatory Impact Analysis accompanying the proposed ELG, EPA analyzed the economic impact of the proposal from several perspectives: compliance cost impacts on utilities, impacts on electricity markets, impacts on electricity costs and prices, and other impacts (e.g., impacts on residential and industrial consumers).

Impacts on Utilities

For this part of the analysis, EPA looked at plant-level costs. For the majority of existing steam electric plants, EPA estimated that compliance costs would be small. Under the four preferred regulatory options, 92%-97% of plants nationally are estimated to have costs less than 1% of revenue. Regionally, plants in the Midwest and Southeast are generally expected to have the highest compliance costs.

To assess compliance costs to steam electric plants, EPA considered costs on both a pre-tax and after-tax basis. Pre-tax costs provide insight on the total expenditures as initially incurred by the plants. According to EPA, 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.[25] **Table 2** summarizes EPA's estimates of compliance costs, on a pre-tax and after-tax basis, as well as social costs. Total social costs reflect the full value of the resources used for compliance, whether they are paid for by the regulated plants or

---

[22] EPA estimated the number of existing plants that would incur compliance costs under each option: under Option 3a, 66 plants would incur compliance costs; under Option 3b, 80 plants; under Option3, 155 plants; and under Option 4a: 200 plants. Under Options 4 and 5 (which are not preferred options), 277 plants would incur compliance costs. 78 *Federal Register* 34485, table IX-3.

[23] In fact, EPA expects that a small number of plants may incur compliance costs when accounting for retirements, repowerings, and conversions that have been announced since August 2012 and accounting for announced retirements, repowerings, and conversions that are scheduled to occur by 2022. Thus, the analyses overstate total compliance costs by assigning costs to units and plants that would no longer operate by the time the proposed ELG would need to be implemented.

[24] 78 *Federal Register* 34481.

[25] RIA, p. 3-6.

by all taxpayers in the form of lost tax revenues. Social costs of regulatory actions are the opportunity costs to society of employing resources to prevent the environmental damage otherwise occurring from discharges of wastewater containing metals, nutrients, and other pollutants.[26] To estimate social costs, EPA uses pre-tax costs.

Table 2. Total Annual Compliance Costs and Annualized Social Costs of Regulatory Options

(Millions of 2010$)

Option	Total Pre-Tax Compliance Costs	Total After-Tax Compliance Costs	Annualized Social Costs	
			3% Discount Rate	7% Discount Rate
Option 3a	$168.1	$108.4	$185.2	$164.6
Option 3b	$264.6	$182.2	$281.4	$257.2
Option 3	$561.3	$389.0	$572.0	$545.3
Option 4a	$947.8	$635.7	$954.1	$914.7

Source: EPA, RIA, Table 3-2, p. 3-7; EPA, Benefit- Cost, Table 11-1, p. 11-5.

Notes: EPA estimated the annualized social costs using two discount rates: 3% and 7%. The 3% discount rate reflects society's valuation of differences in the timing of consumption; the 7% discount rate reflects the opportunity cost of capital to society. In Circular A-4, the Office of Management and Budget recommends that 3% be used when a regulation affects private consumption, and 7% be used in evaluating a regulation that will mainly displace or alter the use of capital in the private sector. See Benefit-Cost, p. 1-2.

Electricity Market Impacts

EPA also examined impacts of the proposal on electricity markets. This analysis looked at changes in capacity to plant or unit closures (i.e., capacity closures and avoided closures); changes in the price of electricity (due to increased generation costs); changes in generation; and changes in cost of generating electricity including fuel costs, capital, and O&M.[27] Overall, EPA concluded that the proposed ELG would not significantly affect total costs of electricity production either in the short run (2020) or the long run (2030). Under Option 3, the electricity market would generate 286 million kWh less electricity in 2020 and 62 million less kWh in 2030; under Option 4, it would generate 884 million kWh less in 2020 and 81 million kWh less in 2030. Few if any generating units are expected to retire as a result of ELG. Option 3 results in avoided closures, and Option 4 results in net closure of 9 EGUs (14 closures and 5 avoided closures), but no full plant closures.

In the long term (in 2030), under Option 3, the net change in total capacity would be relatively small and actually would increase by 106 MW (0.02%) due to avoided plant closures. Nationally, total annual costs would increase by 0.6%, so this option is expected to have relatively little economic consequence. Under Option 4, in 2030, small reductions in steam electric generating capacity and electricity generation are expected to occur. The agency's model projects a 1.4%

[26] Benefit-Cost, p. 11-4.

[27] This analysis only looked at two of the four preferred options—Options 3 and 4—because impacts of Option 4a are expected to be between those of Options 3 and 4, and impacts of Options 3a and 3b are less than those of Option 3.

increase in total costs nationally in 2030, with the largest increases regionally in the Southeast and Midwest.

EPA also analyzed impacts in the short term (2020) to capture the period when plants would be implementing compliance technologies. Under Option 3, EPA projects market-level results for all plants. At the national level, total production costs would increase by 0.4%, and under Option 4, at the national level, total production costs would increase by 1.1%.

EPA estimates that coal-based electricity generation along with coal consumption would decline slightly under the proposal—declining less than 0.1% under Option 3 and declining by 0.3% under Option 4. Generation using other fuels, including gas, nuclear power, and renewable fuels such as biomass, would increase modestly. The largest increase in fuel use is a 0.4% increase in natural gas under Option 4. No coal plants are projected to close as a result of the rule.[28]

EPA acknowledges some uncertainties in these analyses. For example, it assumes that electricity demand at the national level would not change between the baseline and post-compliance options, and the model does not capture changes in demand that may result from electricity price increases associated with proposed ELG. Also, fuel prices—differences in actual fuel prices vs. modeled prices, such as lower natural gas prices—would be expected to affect the cost of electricity generation and the amount of electricity generated, but effects of fuel prices are not reflected in the analysis.

Other Impacts

EPA examined impacts of the ELG on residential, commercial, industrial, and transportation consumers and concluded that industrial consumers would experience the highest price increases relative to their baseline electricity price (ranging from 0.07% to 0.41% nationally, depending on the option), while residential consumers would experience the lowest price increases (0.04% to 0.23% nationally, depending on the option). Residential household electricity costs would increase on average $0.48 annually under Option 3a, $0.75 under Option 3b, $1.59 under Option 3, and $2.69 under Option 4a.

EPA also performed an analysis to estimate employment changes in the directly regulated electric power industry sector. The analysis concluded that employment effects would be positive under all of the preferred regulatory options, that is, that there could be average annual job increases ranging from 168 under Option 3a to 865 under Option 4a. EPA notes that these estimates are likely to be over-estimated because of the methodologies used in the analysis.[29]

Many stakeholders and other observers have criticized EPA for not analyzing the impacts of its regulatory proposals on jobs, the labor market, and the economy broadly, arguing that the agency fails to consider the economy-wide effects of its rules. EPA does not have a robust methodology to fully assess impact of all possible changes in employment, so it is difficult for the agency to project how the ELG would affect employment levels in the entire U.S. economy. Thus, EPA did not quantify long-run economy-wide regulatory changes in employment resulting from the ELG, which would depend on how the electric power sector adjusts to regulatory requirements, as well

[28] RIA, p. 10-10; U.S. Environmental Protection Agency, *Proposed Effluent Limitation Guidelines & Standards for the Steam Electric Power Generating Industry*, EPA-821-F-13-002, April 2013, p. 2.

[29] 78 *Federal Register* 34502-3.

as indirect upstream and downstream effects in the rest of the economy, and the overall state of the economy and the labor market.[30]

Environmental Benefits/Pollutant Reductions Compared with Costs

EPA estimated the reduction of conventional, non-conventional, and priority (toxic) pollutants that would result from the regulatory proposal. The projected pollutant reductions are 484 million pounds per year under Option 3a, 932 million pounds under Option 3b, 1.64 billion pounds under Option 3, and 2.65 billion pounds under Option 4a. Under all of the options, the largest amount of pollutant reduction (more than 96%) is nonconventional pollutants, such as ammonia, phosphorus, and TDS. Additionally, the regulatory options would eliminate or reduce water withdrawals associated with wet fly ash and bottom ash transport and wet FGD scrubbers by 50 billion gallons per year (Option 3a), 52 billion gallons per year (Option 3b), 53 billion gallons per year (Option 3), or 103 billion gallons per year (Option 4a).[31] Reduced water usage is significant, because total water withdrawals by the steam electric industry (primarily for cooling purposes) are larger than those of any other category of use.[32]

EPA expects a number of environmental and ecological improvements and reduced impacts to wildlife and human health to result from reductions in effluent loadings for the different proposed options. The agency conducted an environmental assessment that examined several beneficial outcomes, including improvements in water quality, reduction in impacts to wildlife, and reduction in number of receiving waters with potential human health cancer and non-cancer risks.

In that analysis, EPA estimated that reduced pollutant loadings to surface waters would improve water quality by reducing metal concentrations to receiving waters. Metals in combustion wastewater discharges such as arsenic, cadmium, copper, and chromium can drastically alter aquatic populations and communities and the surrounding ecosystems that rely on them. Option 3a would reduce metal concentrations by up to 33% on average, while the other options for regulating existing sources would provide greater metals reduction—up to 48% under Option 4a. Selenium is the metal most frequently associated with environmental impacts following exposure to combustion wastewaters.[33] On average, total selenium receiving water concentrations would be reduced from 33% to 60% under the preferred options.

Using minks and eagles as representative indicator species, EPA estimated the impacts to wildlife that consume fish exposed to steam electric discharges. The agency calculated that the number of immediate receiving waterbodies with potential impacts to wildlife would be reduced, ranging from 23% reduction of impacted waterbodies under Option 3a to 51% reduction under Option 4a.

Further, EPA estimated that reductions in arsenic loadings from the proposed options would result in a reduction in potential cancer risks to humans that consume fish exposed to combustion wastestream discharges. The EPA model calculated reduction in waters that contain fish

[30] RIA, pp. 6-9 – 6-10.

[31] Benefit-Cost p. 1-1.

[32] Water withdrawals for thermoelectric power were 195 billion gallons in 2000, or 48% of total withdrawals. U.S. Geological Survey, *Estimated Use of Water in the United States in 2000*, Circular 1268, 2004.

[33] 78 *Federal Register* 34505.

contaminated with inorganic arsenic that would present cancer risks above the one-in-a-million threshold and determined that immediate receiving waters with cancer risks above that threshold would be reduced up to 40% after compliance with Option 3a, and up to 80% under Option 4a. Likewise, EPA estimated reduced risk of systemic and other effects to humans, such as neurological and developmental effects, and calculated that exceedances of non-cancer reference doses from fish consumption would decrease in up to 19% of surface waters under Option 3a and up to 53% of surface waters under Option 4a.

EPA acknowledges that there are varying degrees of completeness and rigor in its ability to assess benefits. Where possible, EPA quantifies expected effects and quantifies associated human health and ecological benefits—such as reduced incidence of cancer from arsenic exposure via fish consumption—but EPA is able to monetize only a small subset of health benefits associated with reduced steam electric discharges. Other benefits can be quantified, but not monetized, such as reduced non-cancer adverse health effects. Finally, due to data limitations and gaps in understanding how society values certain water quality changes, some effects can be neither quantified nor monetized, such as reduced sediment contamination and increased property values from water quality improvements.[34]

As shown in **Table 3**, total annualized monetized benefits (human health, recreational uses, improved ecological conditions, groundwater quality, avoided impoundment failures, air-related, reduced water withdrawals) range from $312 million under Option 3, to $606 million under Option 4 at a 3% discount rate; or $230 million under Option 3, to $425 million under Option 4 at a 7% discount rate (each of those numbers reflects a range). Benefits were inferred but not estimated for some options, but EPA expects that the benefits of Options 3a and 3b to be less than those of Option 3, and benefits of Option 4a to be between those of Options 3 and 4.

Table 3 also shows the net annual monetized benefits (i.e., benefits minus costs) for the four preferred options. Net benefits are negative under all of the preferred options, meaning that costs are greater than monetized benefits, even allowing for analytic challenges in quantifying benefits of clean water rules. Still, it should be noted that the CWA does not require that the benefits of regulation exceed or even equal the costs. It does require that effluent limitations "result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[35]

An alternative way to look at the regulatory options is by incremental analysis, looking at how the net benefits change from option to option, which EPA also calculated, as shown in **Table 3**. At a 3% discount rate, the incremental change in mean net benefits in moving from Option 3a to 3b is an additional -$30.1 million (the negative value indicates that the increase in costs is larger than the increase in benefits), while the increment is -$184.5 million when moving from Option 3b to Option 3, and -$203.9 million when moving from Option 3 to Option 4a.

[34] Quantifying and monetizing the benefits of regulations is challenging because of a large number of uncertainties in approaches used to value benefits. In connection with a separate current CWA rulemaking concerning cooling water intake structures (CWIS), EPA has attempted to improve its analysis of benefits by conducting a national survey of consumers' willingness to pay. It attempts to determine how much ratepayers would be willing to pay to reduce fish losses and mitigate other aquatic impacts from CWIS. The survey has been controversial, and critics say that it is likely to overstate the benefits of strict regulation. For discussion, see CRS Report R41786, *Cooling Water Intake Structures: Summary of EPA's Proposed Rule*, by Claudia Copeland. EPA is not proposing to conduct a similar willingness to pay survey in connection with the power plant ELG.

[35] CWA §301(b)((2)(A); 33 U.S.C 1311(b)(2)(a).

Table 3. Total Annualized Benefits and Social Costs by Regulatory Option and Discount Rate

(Millions of 2010$)

Option[a]	Total Monetized Benefits[b]		Total Social Costs		Net Annual Monetized Benefits		Incremental Net Annual Monetized Benefits	
	3%	7%	3%	7%	3%	7%	3%	7%
Option 3a	$139.4	$104.8	$185.2	$164.5	-$45.8	-$59.8	-$45.8	-$59.8
Option 3b	$205.5	$153.0	$281.4	$257.2	-$75.9	-$104.2	-$30.1	-$44.4
Option 3	$311.7	$230.4	$572.0	$545.3	-$260.4	-$314.9	-$184.5	-$210.7
Option 4a	$480.8	$342.3	$954.1	$914.7	-$463.3	-$572.4	-$203.9	-$257.5

Source: EPA, *Benefit and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA-821-R-13-004, April 2013, Table 12-1, p. 12-2.

Notes: Values are based on the discounting of costs and benefits to 2014, the rule promulgation year. EPA estimated the annualized value of future benefits using two discount rates: 3% and 7%. The 3% discount rate reflects society's valuable of differences in the timing of consumption; the 7% discount rate reflects the opportunity cost of capital to society. In Circular A-4, the Office of Management and Budget recommends that 3% be used when a regulation affects private consumption, and 7% be used in evaluating a regulation that will mainly displace or alter the use of capital in the private sector. See Benefit-Cost, p. 1-2.

a. Includes preferred regulatory alternative for existing sources and Option 4 for new sources.

b. EPA did not estimate monetized benefits of Options 3a, 3b and 4a; the values included in the table represent benefits inferred by EPA, for illustrative purposes, based on the agency's analyses of all other options.

EPA also analyzed the cost-effectiveness of the four preferred options. Cost-effectiveness refers to the relative efficiency of alternative regulatory options in removing toxic pollutants from effluent discharges. It is defined as the incremental annual cost (in 1981 constant dollars) per incremental toxic-weighted pollutant removals for that option. For the four preferred options for existing sources, Option 3a is the most cost-effective ($27), and Option 4a is the least cost-effective ($57). Options 3a and 3b were estimated to have cost-effectiveness of $31 and $44, respectively.[36] Cost-effectiveness of controls for new sources cannot be easily determined, because it is difficult to predict which plants will construct new units, the exact characteristics of such units, or timing of new unit construction.

Issues

Steam electric power plants are highly technical and complex industrial operations. So, too, the proposed ELG is very technical and complex. As described in this report, EPA has identified and is seeking public comment on four preferred options that apply to seven types of power plant wastestreams, and it has proposed discharge limits for direct and indirect existing and new sources. The agency has already extended the original 60-day public comment period for 45 days more, until September 20, 2013, which was less of an extension than utility companies had requested. Stakeholders are preparing their public comment submissions now.

[36] See 78 *Federal Register* 34504 for discussion.

Some of the issues likely to be raised by stakeholders were previewed at an EPA public hearing on portions of the proposed rule in July.

Industry is concerned that EPA will set overly stringent standards that will be an economic burden on generators and may not be achievable. The technology bases of EPA's proposal are available, companies generally agree, but they may require extensive retrofitting that is costly and could reduce generating plant effectiveness, and some may be infeasible (e.g., may not be physically possible within the plant's footprint). Many in industry are concerned that the CWA rules will impose new requirements at the same time that power plants are implementing other EPA rules, especially Clean Air Act rules. EPA has attempted to address the issue of timing by proposing that the revised ELG would take effect no sooner than 2017 for existing sources and would be implemented through 2021 and by proposing steps to coordinate the CWA rule with RCRA requirements.

One issue concerns impacts of the proposal on small entities, including small businesses and small governmental jurisdictions. The Regulatory Flexibility Act (RFA) requires agencies to prepare a regulatory flexibility analysis of most rules, and the RFA as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) requires EPA to convene a Small Business Advocacy Review Panel for most rules, unless the agency can certify that a rule will not have a significant economic impact on a substantial number of small entities.[37]

EPA did analyze impacts of the proposed ELG on small entities. It determined that small entities (municipalities and rural electric cooperatives) own 18% of the 1,079 steam electric plants subject to the proposal. More than half of generating units owned by small entities are 50 MW or smaller. EPA found that 14 plants may incur compliance costs under at least one of the regulatory options. However, EPA expects that economic impacts will be minimized by its proposal that EGUs with a capacity of 50 MW or smaller would not be subject to more stringent requirements (i.e., for these units, BAT would be equal to current BPT standards). As a result, EPA estimated that no more than six small entities would incur costs exceeding 1% of revenue, and no more than four entities would incur costs exceeding 3% of revenue—a small number in absolute terms and as a percentage of the total number of small entities, according to EPA. Under some options (e.g., Option 3a and 3b), no small entities would have costs exceeding 1% of revenue. Consequently, EPA found that none of the preferred options in the ELG support a finding of significant economic impact on small entities, and it certified that finding in the proposal.[38]

Nevertheless, a number of stakeholders are concerned that EPA has underestimated costs of portions of the rule (for example, by overestimating the bottom ash removal efficiencies of power plants) and that the rule will affect small entities disproportionately. Some are critical that EPA did not convene a SBREFA panel, with small business representatives participating, to evaluate the impact prior to the proposed rulemaking.[39]

Environmental advocates view the proposed ELG differently from industry. Many urge that EPA adopt Options 4 or 5 for existing sources, because these options would require the most environmentally protective technologies (i.e., dry handling of fly ash and bottom ash by all plants,

[37] 5 U.S.C. §§601 et seq.

[38] 78 *Federal Register* 34528-34530.

[39] In June 2011, EPA issued a notice inviting small businesses to nominate representatives to participate in a SBREFA panel in connection with the rule. However, no panel was convened.

and chemical precipitation plus biological treatment or evaporation of FGD scrubber waste by all plants). They do not support adoption of regulatory options such as Options 3a and 3b that would set BAT equal to current BPT standards for some wastestreams and thus allow continued use of surface impoundments for bottom ash and combustion residual leachate, because surface impoundments can be a significant source of contamination of surface and ground water. EPA acknowledges that Options 4 and 5 would provide greater pollution control, but it rejected these options because of higher compliance costs.

Documents available in the public docket for the ELG rulemaking support criticisms that have been raised by environmental groups that, during review of the rule by the Office of Management and Budget (OMB), substantive changes were made to EPA's proposal. New regulatory options, 3a, 3b, and 4a, were added, and EPA's preferred regulatory options for existing sources were changed. In the document submitted to OMB for interagency review, pursuant to E.O. 12866, Options 3 and 4 were co-proposed as preferred options for existing sources. In the final document released on April 19, Option 4 is no longer a preferred option for existing sources; Option 3 remains a preferred option; and Options 3a, 3b, and 4a were also identified as preferred options. Several changes in methodology were made, including calculation of monetized benefits from reduced impoundment failures. All of the final changes to the proposal from the document submitted by EPA to OMB are identified in a "redline" version of the proposal that is included in the regulatory docket.[40] Environmental groups assert that OMB's changes to the rule were improper and result in a weaker proposal with less control of toxic waste discharges than EPA had developed.[41]

Some environmental advocates do not support EPA's proposal to allow power plants additional time for compliance if they agree to close coal ash storage impoundments and take other steps beyond requirements of the ELG (see "Voluntary Incentive Program Allowing Additional Time for Compliance"). They argue that the proposed incentive plan would undercut the need for a strict coal ash disposal rule under RCRA. According to environmental groups, both a CWA rule to limit liquid discharges and a RCRA rule to address transport, handling, and storage of wastes are needed for a comprehensive regulatory structure of coal combustion waste. Consequently, these groups have criticized discussion in the proposal suggesting that EPA is now considering designating coal combustion residual waste as nonhazardous, rather than hazardous (see "The Proposed ELG and the CCR Rulemaking under RCRA").

Conclusion

As noted in the introduction to this report, EPA rules affecting steam electric power plants have been scrutinized and challenged based on their stringency, feasibility, and projected compliance costs. Some argue that these rules may change the economics of power production, the fuel profile of the electricity market, and electricity rates. Congressional interest has been evident in legislation that has been introduced to alter the direction and substance of some of EPA's regulatory actions and initiatives. Some bills have passed the House, and several provisions of

[40] "Summary of the Substantive Changes Made During Interagency Review Under Executive Order 12866," http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OW-2009-0819-2237.

[41] Environmental Integrity Project, et al., *Closing the Floodgates: How the Coal Industry is Poisoning Our Water and How We Can Stop It*, July 2013, 48 p.

appropriations bills have been enacted.[42] To this point, discussion of the power plant ELG has centered on the administrative proceedings at EPA and has not drawn attention of lawmakers.

[42] For discussion, see CRS Report R41561, *EPA Regulations: Too Much, Too Little, or On Track?*, by James E. McCarthy and Claudia Copeland.

Appendix. Steam Electric Power Plant Wastestreams Regulated under the Proposed ELG

This Appendix provides additional detail on the seven wastestreams from steam electric power plants that EPA proposes to regulate.[43]

FGD Wastewater

FGD systems remove sulfur dioxide from the flue gas so that it is not emitted into the air. There are approximately 401 FGD systems either currently operating or that will be installed by January 2014. Approximately 90 are dry systems that do not generate any wastewater systems, while 311 are wet FGD systems that generate a slurry. Dry FGD systems typically remove 80% to 90% of the SO2, which is less than a wet FGD system which in some cases can remove up to 99%. In wet FGD systems, the flue gas stream comes in contact with a liquid stream containing a sorbent, which is used to effect the transfer of pollutants from the flue gas to the liquid stream. EPA identified 72 steam electric plants with dry FGD systems and 145 steam electric power plants that generate FGD wastewater from wet FGD systems. Of the 145 with wet FGD systems, 117 discharge FGD wastewater after treatment using one or more of several technologies alone or in combination, including surface impoundments, chemical precipitation systems, biological treatment, vapor-compression evaporation systems, and constructed wetlands. The remaining 28 plants do not discharge wastewater to surface waters or POTWs. EPA estimates that the steam electric industry discharged a total of 24 billion gallons of FGD wastewater in 2009. Wastewaters generated by wet FGD systems generally contain significant levels of metals and other pollutants of concern. EPA found that treatment technologies are available to treat these pollutants in FGD wastewater; however, most plants use only surface impoundments that are designed primarily to remove suspended solids from FGD wastewater via settling.

Historically, power plants relied on surface impoundments to treat FGD wastewater because NPDES permits generally focused on controlling suspended solids for this wastestream. Today, 54% of plants that discharge FGD wastewater rely on this technology alone, which is the technology basis for current BPT effluent limits. Metals in FGD wastewater are present both in particulate form, which can be substantially removed by settling (e.g., arsenic), and in soluble (i.e., dissolved) form that is not effectively and reliably removed by surface impoundments. More advanced technologies are available that are effective at removing both soluble and dissolved forms of metals, as well as nitrogen and TDS. EPA is co-proposing three options that include such technologies and is co-proposing options under which some or all facilities would be subject to a site-specific determination by permitting authorities of what constitutes BAT (i.e., BPT). The technology basis for options 3, 3b (for plants with a total wet-scrubbed capacity of 2,000 MW or more), 4a, and 4 (for NSPS) is chemical precipitation/coprecipitation used in combination with anoxic/anaerobic biological treatment to optimize removal of selenium. Three percent of U.S. plants that discharge FGD wastewater use this combination of technologies. Six U.S. power

[43] Sources: U.S. Environmental Protection Agency, "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule," 78 *Federal Register* 34432-34543, June 7, 2013, and U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Document No. EPA-821-R-13-005, April 2013.

plants operate FGD treatment systems that include a biological treatment stage to reduce nitrogen compounds (nitrate/nitrite) and selenium. Under Option 3a (for all plants) and Option 3b (for plants with total wet-scrubbed capacity of less than 2,000 MW), the determination of technology would be made by permitting authorities using "best professional judgment," or BPJ.

Fly Ash Transport Water

Fly ash is the combustion residual of fine ash particles entrained in flue gases. Depending on the boiler design, as much as 70% to 80% of the ash from a pulverized coal furnace consists of fly ash. Many plants transport fly ash from the boiler using water as the motive force, known as sluicing. (TDD)

Because current NSPS regulations prohibit the discharge of pollutants in fly ash transport water, all plants built since 1982, as well as many existing generating units that have converted, already have dry fly ash handling systems that use air to transport fly ash to storage silos. EPA estimates that over 80% of existing generating units use dry ash fly handling systems that utilize mechanical, pressure, or other technologies.

EPA identified 393 generating units at 144 plants that transport (i.e., sluice) fly ash with water to a surface impoundment to remove particulates from the wastewater by means of gravity. Thus, steam electric units generating wet fly ash transport water tend to be older units (e.g., more than 30 years old). Most of these plants are located east of the Mississippi River. Fly ash transport water is one of the largest volume flows for coal-fired power plants. EPA estimates that the steam electric industry generated 128 billion gallons of fly ash transport water in 2009, with the average plant generating 4.2 MGD. In addition, amounts released to surface waters from impoundment overflow or discharge totaled 81 billion gallons in 2009. Studies have found that fly ash transport waters generated from wet systems at coal-fired power plants contain significant concentrations of metals, including arsenic, selenium, and mercury.

EPA is proposing 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. As with FGD wastewater, surface impoundments are not effective at removing soluble forms of metals and nutrients.

Bottom Ash Transport Water

Bottom ash, sometimes referred to as boiler slag, is the combustion residual of heavier ash particles collected at the bottom of a boiler. Since 70%-80% of the ash from a pulverized coal furnace consists of fly ash, the remaining 20%-30% is bottom ash. Like fly ash, bottom ash can be transported from the boiler using water and when it is, it is typically directed to an on-site ash impoundment for treatment. EPA found that bottom ash transport waters generated from wet systems at coal-fired power plants contain significant concentrations of the same metals found in fly ash transport water. Bottom ash transport water is an intermittent stream from steam electric units, but it is still one of the larger volume flows. EPA identified 870 EGUs (345 plants)—67% of plants—that wet sluice (transport) at least a portion of their bottom ash to a surface impoundment or a dewatering bin for solids removal. EPA estimates that the steam electric industry generated a total of 255 billion gallons of bottom ash transport water in 2009, with the average plant generating 2.5 MGD. In addition, amounts released to surface waters from impoundment overflow or discharge totaled 157 billion gallons in 2009.

According to EPA, many coal and oil-fired power plants design their bottom ash handling systems either to not use water to transport bottom ash away from the boiler or manage the transport water in a manner that eliminates or reduces the need to discharge bottom ash transport water to surface waters. EPA estimates that by the time the final rule is promulgated in 2014, about 45% of plants will either use dry bottom ash handling systems or will not discharge bottom ash transport water.

For Options 3a, 3b, 3, and 4a (for units less than or equal to 400 MW), EPA proposes effluent limitations and standards for existing sources equal to current BPT effluent limitations, based on technology of gravity settling in surface impoundments to remove suspended solids. For new sources (Option 4) and under Option 4a (for existing units larger than 400 MW), EPA proposes zero discharge, based on either using bottom ash handling technologies that do not require transport water, or managing a wet-sluicing bottom ash handling system to that it does not discharge bottom ash transport water or pollutants associated with bottom ash transport water. About 20% of coal- and petroleum coke-fired units that generate bottom ash operate systems that eliminate the use of transport water. Technologies to achieve zero discharge include mechanical drag systems, remote mechanical drag systems, and impoundment-based systems that are managed to eliminate all discharge of bottom ash transport water and associated pollutants.

Combustion Residual Leachate from Surface Impoundments and Landfills

Combustion residuals include fly ash, bottom ash, and FGD solids, which are generally collected by or generated from air pollution control technologies. These residuals may be stored at the plant in on-site landfills or surface impoundments (ponds). Based on industry surveys, EPA says that there are about 228 plants that operate combustion residual landfills and 264 plants that operate combustion residual surface impoundments. When a landfill or impoundment has reached its capacity, it will typically be closed to protect against environmental release of pollutants in the waste. However, these landfills or impoundments may continue to generate leachate, which is the liquid that drains or leaches from a landfill or surface impoundment. EPA estimates that 66 plants generate approximately 6.6 billion gallons per year of combined impoundment and landfill leachate.

In addition to leachate, stormwater that enters the impoundment or contacts and flows over the landfill would be contaminated with combustion residual pollutants, such as heavy metals. Power plants manage these wastewaters in various ways. Stormwater collection systems typically consist of one or more small impoundments. Most landfills and some impoundments have leachate collection systems, which may be combined with stormwater or sent to a separate impoundment. According to EPA, 63% of combustion residual landfills and 51% of combustion residual impoundments are lined. Unlined impoundments and landfills to not collect leachate that migrates away from the impoundment or landfill, which can potentially cause groundwater and/or drinking water contamination.

Once collected, the landfill or impoundment leachate can be recycled back to the landfill or impoundment or within the plant, or it is discharged. Some plants discharge the effluent from leachate impoundments, while others send the leachate impoundment effluent to another impoundment that handles ash transport water or other systems.[44] Surface impoundments are the

[44] At some plants, leachate from impoundments and landfills is not collected and can potentially migrate to nearby groundwaters or surface waters.

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. Physical/chemical and chemical precipitation technologies also have been demonstrated capable of treating pollutants in combustion residual leachate.

For Options 3a, 3b, 3, and 4a, EPA proposes effluent limitations and standards for existing sources equal to current BPT effluent limitations, based on technology of gravity settling in surface impoundments to remove suspended solids. The rule would remove leachate from the definition of low volume wastes[45] 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). For new sources, under Option 4 the technology basis of the rule proposes chemical precipitation/coprecipitation. Such 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, and, like FGD wastewater, combustion residual leachate is similarly amenable to chemical precipitation treatment.[46] However, as is the case with FGD wastewater, this technology is not effective at removing selenium, boron, and other parameters that contribute to TDS (e.g., magnesium, sodium).

Flue Gas Mercury Control (FGMC) System Wastewater

In response to recent Clean Air Act rules and other state regulations requiring limits on air emissions of mercury and other air toxics, plants are beginning to install systems to improve removals of mercury from flue gas emissions. Thus, these systems are relatively new to the steam electric industry. FGMC systems remove mercury from the flue gas, so that it is not emitted into the air. In 2009, there were approximately 120 operating FGMC systems, with an additional 40 planned for installation by 2020. Approximately 90% of the currently operating FGMC systems are dry systems that add oxidizers to the coal prior to combustion and move the oxidized mercury in the wet FGD system. Using oxidizers does not generate a new wastestream, but the mercury concentration in FGD wastewater may be increased as a result, because oxidized mercury is more easily removed by the FGD system. About 6% of the currently operating systems involve injection of activated carbon into the flue gas to adsorb the mercury, which can generate a new wastestream at a plant that is likely sent to a surface impoundment.[47] According to EPA, coal-fired power plants can minimize or eliminate the discharge of FGMC particulate handling transport water using the same technologies that are available for fly ash, such as wet or dry vacuum pneumatic systems, pressure systems, or combined vacuum/pressure systems. EPA identified 6 plants that manage their FGMC waste with systems that use water to transport the waste to surface impoundments.

Under all of the four preferred options for existing sources and Option 4 for new sources, the technology bases would be zero discharge using dry handling technologies to store and dispose of fly ash without utilizing transport water. Effluent limits based on dry handling would completely

[45] Under the current ELG, low volume waste sources include a variety of wastestreams, such as wastewater associated with wet scrubber air pollution control systems, boiler blowdown, and floor drains. Plants typically combine low volume wastes with other plant wastewaters for treatment, often in surface impoundments. The proposed ELG would remove FGD wastewater, combustion residual leachate, and carbon capture wastewater from the collective group of low volume waste sources.

[46] EPA did not propose chemical precipitation under Option 4 for bottom ash transport water due to cost considerations.

[47] The type of handling system (wet or dry) for the remaining 4% is unknown.

eliminate the discharge of pollutants in FGMC wastewater. EPA did not propose utilizing surface impoundments, which can remove particulate forms of metals and other pollutants, but are not capable of removing dissolved metals and nitrates. Under all options, EPA proposes to remove FGMC wastewater from the definition of low volume wastes.

Gasification Wastewater

IGCC plants use coal or petroleum coke and subject it to high temperature and pressure to produce a synthetic gas, which is used as the fuel for combined cycle generating plants. After the synthetic gas is produced and prior to combustion, it undergoes cleaning to remove chlorides and other contaminants. This step can generate wastewater and condensate that require treatment prior to reuse or discharge. EPA identified two plants that currently operate IGCC units, a third scheduled to operate in 2013, and a fourth that is scheduled to begin commercial operation in 2014. Two technologies in use to treat gasification wastewaters are vapor-compression evaporation systems and cyanide destruction systems.

The technology basis for the effluent limitations for all regulatory options is vapor-compression evaporation, which is currently used by the two operating IGCC plants and will be used by a third plant scheduled to begin commercial operation soon. Surface impoundments are not effective at removing the pollutants of concern in gasification wastewater.

Nonchemical Metal Cleaning Wastes

Cleaning of metal process equipment, such as boiler tubes, is done to remove scale and corrosion products that accumulate and can retard heat transfer. Wastes that result include the metals of which the boiler is constructed (such as iron, copper, nickel, and zinc) and alkaline reagents used to neutralize the sulfur oxides produced from fossil fuels with significant sulfur content. Some metal cleaning operations occur frequently at many plants, while others are performed infrequently. Surface impoundments and chemical precipitations systems are two of the most common methods of treating metal cleaning wastes, according to EPA. Some plants employ other approaches to control or eliminate the discharge of metal cleaning wastes, such as physical/chemical treatment systems, recycling, or wastewater evaporation, which eliminates the discharge.

The current ELG applies to a broad term, "metal cleaning waste," that does not differentiate between chemical or nonchemical cleaning of metal process equipment. The current ELG for metal cleaning waste includes BPT effluent limits for allowable levels of TSS, oil and grease, copper, and iron in metal cleaning wastes (both chemical and nonchemical). The current ELG includes BAT/NSPS for chemical metal cleaning waste (with limits on TSS, oil and grease, copper, and iron), but not for nonchemical metal cleaning waste. Because some metal cleaning operations do not use chemicals (e.g., air heater cleaning and soot blowing), EPA now proposes BAT/NSPS for nonchemical metal cleaning waste for the same four pollutants covered by the current ELG.

The technology basis for the effluent limitations for all regulatory options is chemical precipitation, which can handle both suspended solids and can precipitate dissolved metals.

Author Contact Information

Claudia Copeland
Specialist in Resources and Environmental Policy
ccopeland@crs.loc.gov, 7-7227