BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In the Matter of: STANDARD FOR THE DISPOSAL OF COAL COMBUSTION RESIDUALS IN SURFACE IMPOUNDMENTS: PROPOSED NEW 35 ILL. ADMIN. CODE 845	)))))))))))	PCB 2020-019 (Rulemaking - Water)

NOTICE OF ELECTRONIC FILING

To: Attached Service List

PLEASE TAKE NOTICE that on August 27, 2020, I electronically filed with the Clerk of the Illinois Pollution Control Board ("Board") the **Prefiled Testimony of Mark Hutson** and **Attachments** thereto, copies of which are served on you along with this notice. Attachments are being filed separately due to size restrictions.

Dated: August 27, 2020

Respectfully Submitted,

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BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)
	)
STANDARDS FOR THE DISPOSAL OF	) R 20-19
COAL COMBUSTION RESIDUALS IN	) (Rulemaking – Land)
SURFACE IMPOUNDMENTS: PROPOSED	)
NEW 35 ILL. ADM. CODE 845	)
	)

PRE-FILED TESTIMONY OF MARK HUTSON

I have been asked to provide input and suggest modifications that I believe are necessary to enhance and strengthen proposed Illinois Pollution Control Board rules pertaining to Coal Combustion Residues (CCR) in Illinois. I view this effort as a long needed and critically important next step in protecting the quality of groundwater and surface water throughout the State of Illinois. A central tenet of responsible waste management is that it be prevention-based. The United States Environmental Protection Agency (EPA) articulated this tenet in its 1993 guidance for owners and operators of solid waste disposal facilities stating: "Ground water is … used extensively for agricultural, industrial, and recreational purposes. Landfills can contribute to the contamination of this valuable resource if they are not designed to prevent waste releases into ground water … Cleaning up contaminated ground water is a long and costly process and in some cases may not be totally successful."[1]

Unlike other forms of solid waste such as municipal solid waste (MSW), inorganic coal combustion residuals and the metals they contain do not biodegrade. Coal ash that is left in unlined storage facilities will be capable of leaching toxic metals into Illinois' groundwater at any time in the present or in the future for as long as soluble metals in the ash are allowed to come into contact with water. Therefore, an effective closure of coal ash storage sites requires that the coal ash waste be securely and permanently isolated from water: including precipitation, surface water, and groundwater.

Failure to isolate coal ash waste from water will result in leaching of contaminants, i.e. formation of leachate. "Leachate" "includes liquid, including any suspended or dissolved constituents in the liquid, that has percolated through or drained from waste or other materials placed in a landfill, or that passes through the containment structure (e.g., bottom, dikes, berms) of a surface impoundment."[2] When released to groundwater or surface water, leachate from coal ash

[1] EPA, 1993, Criteria for Solid Waste Disposal Facilities, A Guide for Owners/Operators, EPA/530-SW-91-089, March 1993. (Attachment 1).

[2] EPA, 2015, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,838, 67,838 and 67, 847 (November 3, 2015) (40 C.F.R. Part 423) (hereafter "EPA, 2015") (Attachment 2).

storage/disposal facility impairs and degrades water quality and the environment. Due to the lack of a bottom liner, unlined CCR facilities “allow the leachate to potentially migrate to nearby groundwater, drinking water wells, or surface waters.”[3]

These facts along with my personal knowledge and experience in investigating and remediating soil and groundwater contamination sites inform my opinions and recommendations for improving the proposed Illinois CCR rules. My review of the proposed rules has shown me that Illinois is off to a good start, but also identifies areas of concern with the current proposal. In this testimony, I intend to highlight issues and provide suggested improvements to address problems that are either not contemplated by the rules or are needed to enhance the effectiveness and protections provided to Illinois residents and the environment.

Qualifications

I express the opinions in this letter based on my formal education in geology and over 40 years of experience on a wide range of environmental characterization and remediation sites. My education includes Bachelor of Science and Masters of Science degrees in geology from Northern Illinois University and the University of Illinois at Chicago, respectively. I am a registered Professional Geologist (PG) in Georgia, Kansas, Nebraska, Illinois, Indiana, Wisconsin, and North Carolina, a Certified Professional Geologist by the American Institute of Professional Geologists, and am a Past President of the Colorado Ground Water Association.

My entire professional career has been focused on regulatory, site characterization, and remediation issues related to waste handling and disposal practices and facilities, for regulatory agencies and in private practice. I have worked on contaminated sites in over 35 states and the Caribbean. My site characterization and remediation experience includes activities at sites located in a full range of geologic conditions, including soil and groundwater contamination in both consolidated and unconsolidated geologic media, and a wide range of contaminants. I have served in various technical and managerial roles in conducting all aspects of site characterization and remediation including definition of the nature and extent of contamination (including developing and implementing monitoring plans to accurately characterize groundwater contamination), directing human health and ecological risk assessments, conducting feasibility studies for selection of appropriate remedies to meet remediation goals, and implementing remedial strategies. Much of my consulting activity over the last 15 years has been related to groundwater contamination and permitting issues at coal ash storage and disposal sites in numerous states, including Alabama, Arizona, Colorado, Georgia, North Carolina, Illinois, Indiana, Kansas, Maryland, Minnesota, Mississippi, Montana, New Mexico, Nevada, North Carolina, Pennsylvania, South Carolina, Virginia, and Wisconsin.

[3] EPA, 2015, at 67,847.

Discussion and Suggestions

My comments provide discussion of and suggested improvements to the proposed Illinois CCR rules. The areas covered are grouped into the following general subject areas, including:

- CCR Must Permanently Be Segregated From Water
- CCR Units Must Be Located In Permanently Stable Locations
- Groundwater Monitoring and Analysis Must be Protective
- Closures and Corrective Actions Must be Effective and Permanent
- The Duration of Post-Closure Care Period Must Reflect the Risk of the Closure

A short discussion and identification of needed improvements to the proposed rules covering each of these general areas is provided below.

1) CCR Must Be Permanently Segregated From Water

CCR that is left in unlined disposal facilities will be capable of leaching metals into groundwater at any time from the present to the distant future for as long as soluble metals remain in the waste and are allowed to come into contact with water. Therefore, an effective closure of CCR storage sites requires that the waste be securely and permanently isolated from water: including precipitation, surface water, and groundwater. Failure to permanently isolate CCR from water will result in leaching of soluble contaminants and is one of the most common issues that I encounter at CCR disposal sites in Illinois and nationwide. This problem stems from the fact that many coal generation facilities were located along the banks of surface water bodies to facilitate the ready availability of cooling water. The depth to groundwater at sites located along rivers and lakes is typically shallow. However, during high water events the measured groundwater elevation can increase dramatically, including up to and above the ground surface. Where unlined CCR disposal facilities are constructed more deeply below the surface, groundwater may be within the disposal unit at all times. Where the unlined waste containment unit is less deep, groundwater migrates into the unit only under high water conditions. The result of both of these conditions is that groundwater flows into disposed CCR, either continuously or intermittently, causing soluble contaminants to be leached into the porewater within the waste and migrate out of the disposed waste as CCR leachate. Once released to groundwater or surface water, leachate from a CCR disposal facility can degrade water quality and the environment.[4]

Industry very commonly proposes capping disposed CCR in place as the preferred closure method. Capping CCR in place can indeed be appropriate in some locations where the CCR disposal unit was successfully designed and constructed to permanently sequester disposed waste

[4] Impacted environmental media may include groundwater, saturated and occasionally saturated soils, surface water, and sediments in the stream-bottom sediment column.

from water. However, the ability of capping in place to adequately sequester disposed CCR is very often limited by the presence of shallow groundwater.

Capping interrupts vertical percolation of water into the waste from the surface. It does nothing however to prevent shallow groundwater from migrating laterally through waste placed below the water table in an unlined landfill or impoundment. It must be made clear that leaving waste in place at or below the highest seasonal zone of subsurface saturation is not allowed.

The need for permanent isolation of the waste from water also dictates that locations subject to regular shallow groundwater conditions, such as floodplains, are not appropriate locations for wastes to be disposed. During high water events, groundwater flows from the river into surrounding sediments and groundwater beneath and within the impoundment will rise in response, resulting in groundwater re-wetting any disposed ash remaining in the impoundment. The result of this re-wetting of ash will be enhanced production of leachate. Even minor but more frequent flood events stimulate formation and release of CCR constituents to groundwater from any CCR that is occasionally saturated by high groundwater. Concerns with potential damage to and/or release of CCR from disposal units allowed to remain in place in unstable and inappropriate locations, such as on floodplains, are discussed in the next section of my testimony.

Without a clear and specific prohibition on leaving CCR in contact with groundwater, owner/operators are free to propose CCR unit closures that fail to contain CCR constituents in the closed CCR disposal unit. Utilities are essentially making the bet that migration of contaminants out of the disposal unit after closure will disperse and be sufficiently diluted such that additional remediation will not be required. Nationwide there are numerous examples of unlined CCR impoundments and landfills that have been constructed such that waste is either constantly or periodically saturated, where groundwater flows through waste. A particularly egregious example of a utility that is pushing the envelope of propriety is provided at Georgia Power's Plant Wansley.[5]

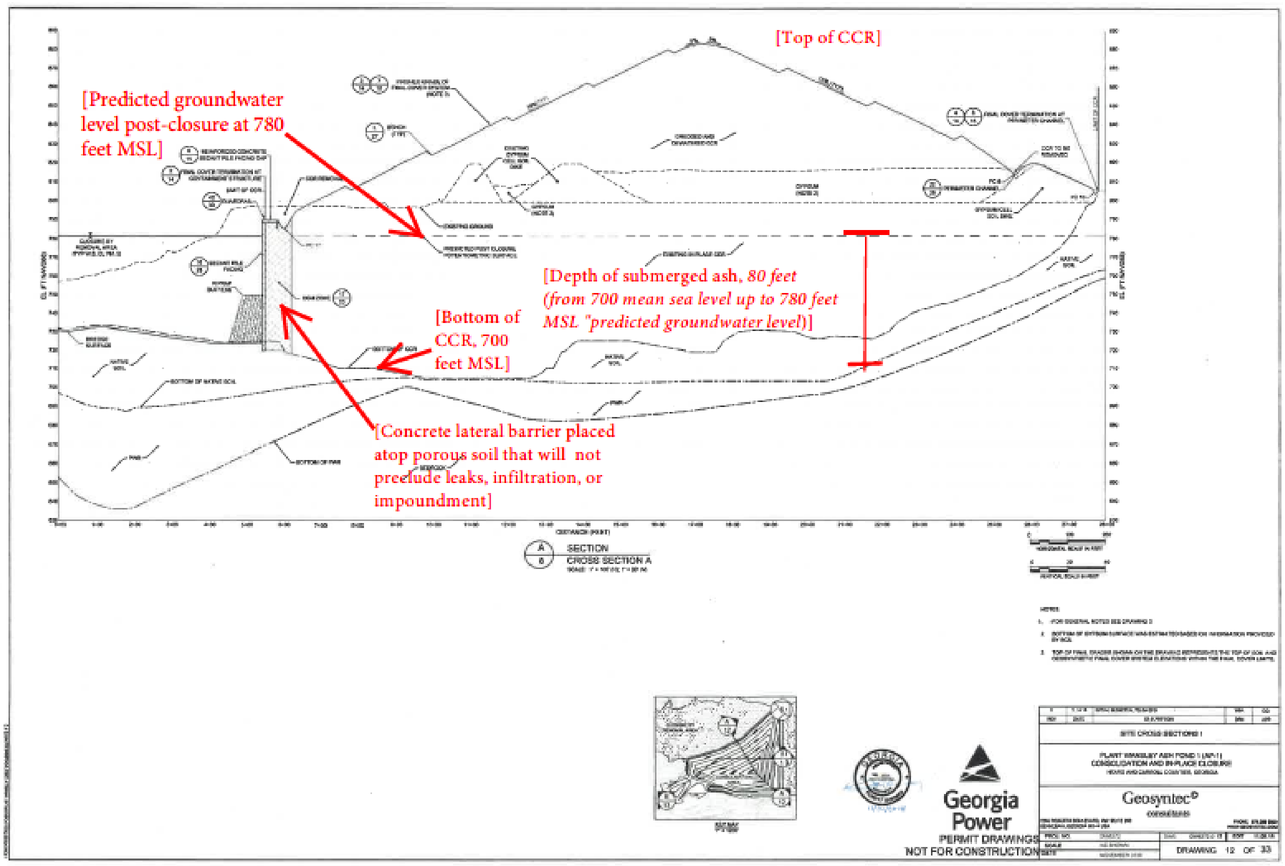
The Plant Wansley Closure Plan establishes Georgia Power's intent to close AP-1 by performing the following major actions:

- Construct a deep soil mix containment structure (berm) with a concrete pile facing to create a 138-acre cap-in-place area (Consolidation Area) that separates the existing coal ash delta from the remainder of the impoundment (Closure-By-Removal Area);
- Dewatering of the CCR located within the Consolidation Area, as necessary to support closure activities;
- Dredging of the CCR from the Closure-By-Removal Area;
- Dewatering and placement of the dredged material within the Consolidation Area;

[5] Geo-Hydro, Inc. Review of Closure Permit Application and Other Pertinent Materials, Plant Wansley Ash Pond 1, July, 2019 (Attachment 3).

- Final grading of the Consolidation Area prior to capping; and
- Installation of a final cover system over the Consolidation Area.

The overarching problem with Georgia Power's proposed Closure Plan is the basic truth that this plan would result in establishing a permanent waste disposal cell within, and over the deepest portions of, the existing impoundment; essentially creating a waste disposal cell within a surface water lake. This is, to my knowledge, an unprecedented closure proposal that upends common precepts of proper waste containment and permanent disposal, which allows the perpetuation of significant pollution rather than the remediation of it. An annotated cross-section through the proposed Consolidation Area and Closure by Removal Area is shown below.[6]



Minimizing the potential for leachate generation and subsequent migration out of containment are key goals that must be achieved at CCR disposal sites that are not achieved under the currently proposed rules. There are several specific areas in the proposed CCR rules that, in my opinion, need to be modified to adequately protect the Illinois environment and public.

Suggested areas for improvement of the proposed rules include:

[6] Drawing shows annotations over a base layer of Closure Drawing 12 of 33.

- 845.120 (Definitions) - The definitions provided with the proposed rules define aquifer, but do not mention perched or other zones of saturation that might be present in some locations above the uppermost "aquifer". The point of the CCR rules should be to keep waste out of water, whether or not it is capable of yielding such quantities. Saturated zones located above the first aquifer can transmit water into waste and facilitate leachate migration from buried waste. The uppermost zone of saturation, as well as the uppermost aquifer, should be defined and incorporated into the CCR rules.
- 845.220(b)(1)(A) (New Construction) - The location standard should be changed from 5 feet above "uppermost aquifer" to 5 feet above "highest seasonal zone of saturation."
- 845.220(b)(1) (New Construction) - The plans should include a demonstration that new CCR impoundments are not located within the area of inundation of the probable maximum flood for the location.
- 845.220(c)(2)(A) (Corrective Action Construction) – Approval of a Corrective Action Plan should be contingent on successful demonstration that ash will not be in intermittent, recurring, or sustained contact with water.
- 845.220(d)(1)(A) (Closure Construction) – Approval of a Closure Plan should be contingent on successful demonstration that ash will not be in intermittent, recurring, or sustained contact with water.
- 845.220(a)(3) (Site Location Map) – The location maps should show the boundaries of the probable maximum flood as well as the 1% annual probability flood. Floods with a probability of 1% in any year are becoming more common as the climate warms. The probable maximum flood is a better indicator of potential risks to waste disposal units located in flood-prone areas.
- 845.230(d)(2) (Initial Operating Permits) – Initial operating permits for inactive, or inactive closed CCR surface impoundments must require submission of structural stability assessment, safety factor assessment, and inflow design flood control system plan.
- 845.300 (Placement Above the Uppermost Aquifer) – The requirement must be revised to state that the base of the surface impoundment must be no less than five feet (1.52 meters) above the uppermost zone of saturation.
- 845.700 (Required Closure or Retrofit of CCR Surface Impoundments) – The trigger for required closure due to upper aquifer location should be modified to require closure of any unit that has waste placed within five feet (1.52 meters) above the uppermost zone of saturation.
- 845.750 (Closure with a Final Cover System) - Closure of unlined CCR units in place should only be permitted if the owner demonstrates that there will be no intermittent, recurring, or sustained hydraulic connection between CCR and groundwater following closure.

2) CCR Units Must Be Located In Permanently Stable Locations

The Illinois Pollution Control Board should consider floodplains as unstable locations for the purposes of the CCR rule. Storm-induced high water events are capable of overtopping berms and increase the potential for catastrophic release of wastes. Rising water elevations caused by even minor high water events will re-wet CCR contained in the unlined disposal unit and renew production of leachate each time.

Sites located on active floodplains are subject to hydrologic and geomorphic processes which, over time, will damage facilities and eventually cause catastrophic releases of stored wastes. Locating waste containment structures within the 100-year floodplain should be viewed, at best, as unacceptable waste management planning and a practice that will facilitate contamination of waters of the state and have potentially catastrophic results for future residents. Large flood events will eventually create flood conditions that will overtop the berms and increase the potential for catastrophic release of wastes. Over the long term, capping CCR impoundments in place on the floodplain is neither secure nor permanent.

River channels are not stationary features. Lateral and/or downstream channel migration or sudden switches of the channel location, likely initiated during a flood event, will eventually impinge on and undercut containment structures. An active floodplain along a meandering river can never be an acceptable location for establishing or maintaining a permanent waste disposal facility. The addition of more coal ash to waste disposal units in such locations is equally unacceptable. The Illinois CCR rules should drive down the volume of waste subject to eventual release during flood events, and prohibiting placement of additional waste on floodplains is an important first step.

Hydrologic dangers to waste disposal sites located on floodplains were illustrated in 2018 when rising floodwaters in Wilmington, North Carolina inundated CCR storage and disposal units at Duke Energy’s L.V. Sutton Steam Plant. Flood waters from storms upstream of the plant sent flood waters from the Cape Fear River through current and former ash impoundments, breached an ash landfill, and released an unknown quantity of ash. Attachment 4 provides articles written at the time describing floodwater inundation of CCR storage and disposal units at these facilities.

Retaining CCR containment structures, whether operating or closed, on a river’s floodplain must be viewed as an unacceptable waste management practice that will facilitate contamination of the waters of Illinois and have potentially catastrophic results for future residents. Since the utility that buries the waste on the floodplain is only responsible for maintaining the facility for 30 years (if groundwater protection standards have been met by that time), facility damage or releases of waste that occur after that time will be left for others to correct. The inadequacy of the 30-year post closure care period is discussed separately in a later section.

Photograph released by Duke Energy shows flooding from the swollen Cape Fear River overtopping an earthen dike at the L.V. Sutton Power Station near Wilmington, NC. (Washington Post, September 22, 2018)

The previous discussions of the hazards involved in siting CCR storage and disposal units on unstable floodplains are not intended to undermine the importance of other site stability concerns. Structural stability assessments, safety factor assessments, and inflow design flood control system plans must be provided to IEPA, made available for public review, and approved by IEPA. Regulators cannot make informed decisions about the level of risk posed by a unit[7] in the absence of assessments and plans pertaining to the structural stability of the site. Public acceptance of any proposed waste management unit requires information and buy-in based on availability of relevant facts. The ability to sequester CCR from water and contain disposed waste in the proposed location requires that unstable conditions, including locations on active floodplains, be identified and unstable locations be eliminated as sites of CCR storage or disposal units. All of the above is true of inactive impoundments as well as active ones. Locations on floodplains and along cut banks of rivers cannot be accepted as being appropriate for the permanent disposal of CCR wastes.

Suggested areas for improvement of the proposed rules to assure that waste is disposed only in stable locations include:

- 845.120 (Definitions) – The definition of unstable areas must be modified to explicitly include locations on a floodplain within the 100-year flood zone and any location on the active floodplain of a meandering river.

[7] The level of risk posed by a unit informs how soon a unit must close and what type of closure and corrective action will be protective of health or the environment, among other things.

- 845.230(d)(2) (Initial Operating Permits) – Initial operating permits for inactive, or inactive closed CCR surface impoundments must require submission of structural stability assessment, safety factor assessment, and inflow design flood control system plan.
- 845.340 (a) (Unstable Areas) – An additional factor to be considered when determining whether an area is unstable should be added. The added factor should make it clear that an existing or new CCR surface impoundment or any lateral expansion of a CCR surface impoundment must not be located on a floodplain within the 100-year flood area of inundation.

3) Groundwater Monitoring and Analysis Must be Protective:

Over the last decade I have personally reviewed monitoring data on scores of CCR disposal sites located in many parts of the country, including Illinois. This experience has shown that there are commonly overlooked elements of groundwater monitoring systems that are often ignored by owner/operators and regulators that must be examined if the monitoring program is to adequately identify impacts to water quality from CCR disposal units. Often overlooked items include:

Determination of the elevation and chemistry of liquid and/or porewater within the CCR unit:

The elevation of liquid and/or porewater inside all CCR impoundments and landfills must be reliably and regularly measured. It is very common practice for the elevation of liquids within impoundments and landfills to go undetermined and unmonitored. Measurement of free liquid and porewater head inside both lined and unlined impoundments and landfills is needed to obtain an accurate approximation of the direction of groundwater flow in the immediate vicinity of unlined units and assist with leak detection in lined units. The apparent water table or potentiometric surface can appear wildly different when the internal leachate elevation is considered than when it is ignored, up to and often including reversal of indicated flow directions on the upgradient side of unlined impoundments. Monitoring wells originally considered as upgradient or background monitoring locations can in fact be impacted by local flow out of the CCR unit. This is a critical issue when considering systems monitoring unlined impoundments and landfills, some of which have maintained high hydrostatic head for several decades.

Unexplained changes in liquid head inside lined CCR impoundments and landfills can provide an initial warning of unwanted changes. Unexplained decreases in liquid head might indicate increased leakage out of a unit, while unexplained increases in liquid elevation might indicate increased infiltration through a cap or inward leakage of groundwater into the unit. Regular collection of porewater and free liquid elevation data is needed to develop normal elevation ranges to be used as baseline values to compare to newly developed data.

Knowledge of the chemical composition of leachate is needed to identify CCR constituents associated with each impoundment of landfill. The chemical composition of leachate and porewater in landfills or impoundments evolves over time as feedstock coal sources, plant processes, sluice volumes, precipitation volumes, waste/water contact time, etc. all change. Porewater chemistry is also horizontally and vertically variable through the disposed CCR. I have observed that concentrations of CCR contaminants in porewater samples vary widely between sample locations. I have also repeatedly observed that samples of impoundment water collected from open water areas of an impoundment or of porewater from the upper portion of the waste column often show lower concentrations of CCR-associated metals than samples collected from deeper in the accumulated waste. These observations make sense when one considers that porewater at the top of the waste column is regularly diluted with infiltrating precipitation and has spent little time in contact with the waste as compared with porewater from lower portions of the CCR unit. This realization causes me to recommend that samples of the porewater source in each CCR unit from multiple locations near the bottom of each unit be required. Collection of impoundment water rather than porewater from near the bottom of the waste is a problem commonly observed in Alternative Source Demonstrations (ASD's). The validity and value of an ASD based on impoundment water rather than porewater chemistry is highly questionable.

Measurement of porewater elevation within CCR units may provide early indications of leakage into or out of a unit. Identification of the range of constituent concentrations in the porewater defines the source concentrations should leakage from a unit develop. Suggested areas for improvement of the proposed rules to assure that liquid contained in impoundments is appropriately characterized and incorporated include:

- 845.620(b) (Hydrogeologic Site Characterization) – This item should be modified to require characterization of the hydraulic characteristics (hydraulic conductivity and porosity) of the source materials and porewater elevation as well as characterization of the underlying migration pathways.
- 845.630(a) (Groundwater Monitoring Systems) – An additional performance standard item should be added that requires that the owner or operator on a CCR impoundment install a monitoring system capable of characterizing the elevation of liquid within the unit as well as the chemistry of leachate collected from near the bottom of the CCR unit during each monitoring event.

Determination of Unambiguous Background Groundwater Quality:

The available data set must be evaluated to determine if reliable and unambiguous background groundwater quality values have been established. Improper or ambiguous background values can be caused by a variety of issues including local flow out of the impoundment (described above), impacts from other nearby facilities, and lithologic changes between upgradient and downgradient monitoring locations. In addition to groundwater quality from wells not affected by leakage from a known CCR unit, the concentration of each parameter in groundwater unimpacted by any site operations should be determined. Unimpacted water quality must be identified so that the effects of unknown source areas and general operations on water quality can be evaluated. Accurate characterization of unimpacted groundwater quality is also needed to distinguish the location of the leading edge of any downgradient contaminant plume.

Comparisons of downgradient water quality to "background" concentration using intra-well analyses are not effective in monitoring an existing facility since intra-well tests do not compare each well against "background". An intra-well analysis compares each well to itself over time.

Suggested areas for improvement of the proposed rules to assure that liquid contained in unlined impoundments is appropriately characterized and incorporated include:

- (845.630)(a)(1) (Groundwater Monitoring Systems) – The performance standard should be modified to indicate that the owner/operator must represent the quality of background groundwater that has not been affected by any site operations as well as water that is not affected by leakage from known CCR sources.
- (845.640)(g)(1) (Groundwater Sampling and Analysis Requirements) – The discussion of selection of the statistical method must clearly indicate that an intra-well method is only applicable to new facilities where monitoring wells are installed and monitoring initiated prior to accepting wastes.

Characterization and Containment of All Contaminants:

The proposed rules establish groundwater protection standards that correspond to 40 CFR 257, Appendix III and Appendix IV. This list certainly captures many common CCR-related groundwater contaminants. However, the proposed list of parameters excludes other parameters that have existing Illinois groundwater protection standards (Section 620.410) that are frequently released to groundwater from CCR storage and disposal sites. The excluded CCR-related parameters include Iron, Manganese, and Vanadium. Illinois EPA in its stakeholder draft provided that both Part 620 groundwater standards and those set forth in the proposed CCR rules would apply, but deleted that provision in this draft. I have personally reviewed CCR monitoring data from multiple CCR sites that show each of these parameters at concentrations elevated above groundwater protection standards in ash porewater and downgradient monitoring wells. Each of these parameters should be included in the list of required analytes at their already existing groundwater protection standard concentrations. Facilities requesting permission to operate or close in place must be capable of containing all CCR contaminants. The Pollution Control Board should not permit facilities to ignore common CCR contaminants that already have existing Groundwater Quality Standards. Suggested areas for improvement of the proposed rules to assure that applicable Groundwater Quality Standards are achieved include:

- 845.600(a)(1) (Groundwater Protection Standards) – The common CCR-related parameters Iron, Manganese, and Vanadium should be included in the list of CCR Groundwater Protection Standards at their existing Part 620 concentrations.

Groundwater Monitoring Program Must Provide Readily Useful Information

In many states the Annual Reports of groundwater monitoring results are bare-bones documents that present the analytical laboratory results with little or no tabulation, no concise summary of statistical test results, no evaluation of trends in contaminant concentrations over time, and no technical discussion of what the data shows. Monitoring reports in some states do not even include groundwater level information or maps upon which to examine flow directions at the time of the sampling event. While these reports meet the meager requirements of some states, they shift the burden of tabulating, plotting, summarizing, and interpreting analytical results on the agency reviewers and make it virtually impossible for the public to read a document and gain an understanding of impacts to groundwater quality from the subject sites. In order to streamline review, monitoring data must be summarized, displayed, tested, and interpreted by the owner/operator with oversight and approval by IEPA. Monitoring data must be made available to both regulators and the public in machine-readable format[8] in order to facilitate efficient review. In an effort to assure that monitoring reports prepared for IEPA and public review are user friendly and provide an appropriate level of detail and interpretation, I make the following suggestions for improvements to the Illinois CCR rules:

- 845.610 (Annual Groundwater Monitoring and Corrective Action Report) - The Annual report should; (a) for unlined impoundments, include the elevation of water/leachate within the unit and descriptions of the local direction of groundwater flow, (b) for all impoundments, include time-series graphs for each parameter at each monitoring location showing concentrations changes over time, as well as a time-series graph of water elevations in each monitoring location, and, provide machine-readable data table in a commonly used format in order to facilitate efficient agency and public data review.

Determine the Size and Extent of Releases

Determination of the size, shape, extent, and concentration of each contaminant released from a CCR storage/disposal facility is necessary to understand the current and potential future risks, to evaluate corrective actions, and to be able to notify potential downgradient receptors of the release (845.650(d)(2)). The proposed rules require that additional monitoring wells necessary to define the contaminant plume(s) be installed, but fails to specify the specific questions to be answered by the characterization. In addition, the monitoring program requirement fails to require that surface water and sediment sampling be conducted in the commonly observed event that contaminant plumes are shown to be migrating toward surface water discharge areas.

While it is often, but not always, difficult to detect contamination in flowing surface water caused by discharging CCR contaminants, detailed sampling of the upper few feet of sediment and/or porewater at the bottom of a stream or lake can often detect metals that have precipitated from solution or attached to sediments as groundwater flows into sediment. Contaminants

[8] Machine–readable formats would include commonly used text, spreadsheet, or database files.

released from CCR and transported from the CCR disposal facility with groundwater flow is often thought of as discharging directly into nearby receptors such as streams and river. In practice however, metals contained in released CCR leachate can accumulate to elevated concentrations in stream-side and/or bottom sediments while contamination of surface water remains undetectable due to high dilution. For this reason it is imperative that characterization of releases into nearby surface water bodies must include detailed investigation of stream-bottom.

Suggested areas for improvement of the proposed rules to assure that applicable Groundwater Quality Standards are achieved include:

- 845.650(d)(1)(a) (Groundwater Monitoring Program) - A sufficient number of wells must be installed inside and outside the leading edge(s) of the contaminant plume to determine the location and rate of movement of the leading edge of the plume and identify contaminant concentrations and internal concentration gradients for each contaminant.
- 845.650(d)(1)(a) (Groundwater Monitoring Program) – The rate of movement of the leading edge(s) must be evaluated in order to estimate the time until the plume reaches the property boundary or potential receptors.
- 845.650(d)(1)(e) (Groundwater Monitoring Program) – A new measure should be added to the list that requires implementation of regular surface water and sediment/sediment pore water sampling in all locations that a contaminant plume may be discharging to surface water. Sediment/sediment porewater sampling must provide for characterization of the sediment/sediment porewater column at regular intervals to the bottom of the sediment column.

Alternate Source Demonstration (ASD) Rules Need Improvement

Alternate Source Demonstrations (ASD's) are utilized by owner/operators to explain statistical exceedances identified in the groundwater monitoring program. Some of the most often utilized explanations provided in ASD's that I have reviewed are changing groundwater flow directions, monitoring wells supposedly impacted by other on-site or off-site operations, and discrepancies between downgradient monitoring and the quality of water within the impoundment. As was previously described, sampling of impoundment water rather than from waste porewater is commonly observed in ASD's. The validity of an ASD based on impoundment water rather than porewater chemistry is highly questionable. The chemical composition of CCR disposed in impoundments is highly variable between locations and depths sampled. This variability requires that multiple samples of disposed CCR be analyzed in order to determine the range of constituent concentrations within the waste. An ASD that claims that results from one or a very limited number of waste samples prove that the disposed CCR is not the source of observed groundwater impacts is essentially ignoring the variability of the source material.

An example of an ASD that claims to prove that a CCR impoundment is not the source of contamination by a CCR-related by parameter is provided at the Dynegy Midwest Generation, Baldwin Bottom Ash Pond. Groundwater monitoring at this site[9] detected Lithium in a downgradient monitoring at concentrations above the applicable groundwater protection standard. An ASD prepared to explain this apparent exceedance consisted of collecting 2 samples of water from within the impoundment for comparison to the downgradient well. One of the samples was of impounded water held in the impoundment and the second sample was of CCR porewater from a piezometer located near the center of the impoundment rather than from near the impacted monitoring well. As I previously discussed, samples of impoundment water collected from open water areas of an impoundment or of porewater from the upper portion of the waste column often show lower concentrations of CCR-associated metals than samples collected from deeper in the accumulated waste. One should not expect that the concentration of impounded surface water within the unit would reflect the chemistry of leachate that has migrated through the waste column and exited the bottom of the impoundment.

Porewater within a CCR disposal unit is horizontally and vertically variable. This variability produces concentrations of CCR-related contaminants in porewater samples that vary widely between sample locations. A single porewater sampled collected at distance from the downgradient monitoring well should not be assumed to represent the chemistry of porewater across the impoundment nor of leachate that has exited the impoundment. Similar issues to these have been identified in sites located in several other states as well as in Illinois. An example of a report describing problems with an ASD at Georgia Power's Plant Scherer is provided in Attachment 6.

An affirmative demonstration of the source and aerial extent of impacts identified as a potential alternative source must be required in order to allow regulatory personnel to ascertain which, if any, monitoring points are affected and what remedial actions, if any, might be necessary. ASDs are currently proposed to be submitted to the approving agency without notification of the public. Since ASDs potentially represent a significant change in our understanding of the site, and ASDs seem to be often offered in an attempt to avoid corrective action requirements, I recommend that Illinois treat an ASD as a permit change requiring notification of the public and approval by IEPA.

In an effort to facilitate public disclosure of ASD's submitted to IEPA I make the following suggestion for improvements to the Illinois ADS rules:

- 845.650(d)(4) (Alternate Source Demonstration) – This section of the rules should be re-drafted to require that ASD's be submitted to IEPA as permit modifications rather than as simple documents that are reviewed and approved or disapproved within 30 days. It

[9] Dynegy Midwest generation, 2020, 2019 Annual Groundwater Monitoring and Corrective Action Report, Baldwin Bottom Ash Pond, Baldwin Energy Complex, January 31, 2020. (Attachment 5).

should also be modified to require an affirmative demonstration of the location of the alternative source and the extent of the source's impacts to water quality.

4) Closures and Corrective Actions Must be Effective and Permanent

The proposed rules specify that closure of a CCR surface impoundment, or any lateral expansion of a CCR surface impoundment, must be completed either by leaving the CCR in place and installing a final cover system or through removal of the CCR and decontamination of the CCR surface impoundment.10 Effective management of coal ash requires that the waste be permanently isolated from water: including precipitation, surface water, and groundwater. Completion of a Closure Alternatives Analysis that examines the "long-and short-term effectiveness and protectiveness of the closure method," along with several other issues including the "ease or difficulty of implementing a potential closure method" is required by the proposed regulations.

Unfortunately, the bottom of many CCR waste units are located at or below the water table so that some portion of the disposed waste is either continually or intermittently wetted. Construction of even the best synthetic cap over the waste will not control formation and migration of leachate in CCR wastes that are continuously or intermittently wetted by contact with groundwater. It is my opinion that the rules should specify that leaving industrial waste in the form of CCR buried in unlined impoundments should be prohibited unless there are at least 5-feet of vertical separation between the bottom of the impoundment and the elevation of the seasonal high groundwater elevation, including any perched water zones, irrespective of whether the water-bearing unit is classified as an aquifer.

In Place Closures

The proposed Illinois CCR rules specify that "Closure must be in a manner that will: Control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere."[11] Capping of CCR units with an engineered composite cap can be useful at sites where the disposed waste is located well above the seasonal high groundwater elevation. At these sites a properly designed, constructed, and functioning cap will reduce the volume of precipitation that infiltrates through the waste. The volume of water that will infiltrate through a cap depends on the design, materials used, and construction quality. Construction of even the best cap over the waste will not control formation and downgradient migration of leachate in CCR wastes that are continuously or intermittently submerged in groundwater. This is the

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[10] Section 845.710 – Closure Alternatives
[11] Section 845.750 – Closure with a Final Cover System

reason for my previous recommendation that in-place closures should not be allowed in locations with shallow groundwater, including floodplains.

Units that violate the aquifer location restriction must not be eligible to receive additional CCR during closure. Addition of CCR during closure of impoundments in contact with groundwater is adding contaminant mass to the source of groundwater contamination. Adding additional mass to the CCR source would extend the duration over which contaminants are released to the environment, may increase the concentration of released contaminants, and have the practical effect of limiting the range of remedial options.

Many sites have proposed In-Place Closures using some combination of cap construction along with remedial such as slurry wall construction, groundwater recovery and treatment, or other methods many of which require frequent maintenance and monitoring. There are several possible combinations of remedies that can be designed, constructed, and operated well enough that contaminant releases are reduced during the 30-year post closure care period. The problem, of course, is that the CCR will supposedly remain in the disposal unit forever, while operation and maintenance of remedial systems, including the cap system, will be allowed to stop after 30 years if the groundwater protection standards have been met by that time. Disposal of CCR must be treated as a permanent problem deserving a permanent remedy, not a remedy that relies on continuing intervention to contain contamination to the disposal site.

Cap System Requirements

Many closure plans for sites that I have recently reviewed have proposed to close CCR sites in place by grading the surface of landfills or impoundments and placing a synthetic cover layer that is composed of geosynthetic cover material with artificial grass attached to shield the cover material from deterioration. Unfortunately, synthetic cover systems left on the surface are subject to deterioration from exposure to sunlight and physical damage from storms, animals, vegetation; and unfortunately, from humans who decades in the future will have forgotten or never known that driving a jeep up the big artificial-grass covered hill down by the river is not allowed. The sales literature for one commonly proposed artificial cover states that “With a design life of 100+ years, the lifespan of the ... system extends well beyond the post-closure maintenance period.”[12] The goal of any CCR unit closure should be to permanently isolate the waste from water. Closure with a system intended only to outlast the typical post-closure care period is clearly inadequate.

The proposed rules allow an owner or operator to demonstrate that another low permeability layer construction technique or material provides equivalent or superior performance. My

[12] ClosureTurf (2018), ClosureTurf, A Predictable Benchmark of Performance at 4. (Attachment 7); ClosureTurf (2018), Frequently Asked Questions. (Attachment 8).

recommendation for improvement of the proposed rules to make Close-In Place systems as secure as possible is:

- 845.750(c)(1) (Final Cover System) – This section of the proposed rules should be modified to specify that the alternative cover system be protected from environmental and human damage, and that the cap system performs as well or better, and the expected life of the cover system is expected to be as long or longer, than the cover system described in the proposed rules.

Monitored Natural Attenuation

Closure plans that propose Monitored Natural Attenuation (MNA) are often submitted for sites located on floodplains and very close to active river channels. In the majority of these sites the only documented "natural attenuation" mechanisms shown to reduce contaminant concentrations are dispersion and dilution, processes that do not actually remove contaminants from groundwater. In other words, many sites propose to simply let their CCR contaminants flow into the river via the groundwater conduit. In order to assure that Closure Plans that rely on MNA are more than the all too commonly proposed "it will not be detectible once it gets in the river" remedy, I propose that additional rules specific to closures that rely at least in part on MNA be developed. Requirements that I suggest should be added include:

- Attenuation mechanisms other than dispersion and dilution must be documented to be acting on the contaminant plume to actually remove contaminants from groundwater.
- There must be a demonstration that the location and rate of movement of the leading edge of any contaminant plumes are reliably identified.
- Any contaminant plumes are documented not to be discharging into receiving surface waters, water supply wells, or other sensitive receptors.
- Attenuation of contaminant in sediment at the bottom of a receiving surface water body does not constitute MNA.

Groundwater Flow and Transport Modeling

The requirements for evaluating closure alternatives (845.710(d)(2)) describe a requirement that the results of groundwater contaminant transport modeling and calculations showing how the closure alternative will achieve compliance with the applicable groundwater protection standards. Because Closure-In Place often leaves CCR containing soluble metals in unlined landfills and impoundments, and because those metals will still be available to leach into water if/when the closure system fails, the requirements for evaluating the short and long-term performance of Close-In-Place remediation must include groundwater fate and transport modeling that critically explores possible long-term closure system performance. The ability of a remedy to continue to contain CCR contaminants in the unit over an extended time must be required. As part of this analysis the owner/operator should be required to model system performance at least until groundwater protection standards have been achieved and include evaluations of how declining closure system performance (such as estimated cap deterioration[13]) will affect compliance with groundwater quality standards. In order to assure that performance issues with Close-In-Place Remedies are evaluated I make the following suggestions for improvements to the proposed rules:

- 845.220(c)(2) (Corrective Action Construction Permits) – This rule should be altered to specify that the groundwater modeling and calculations must show how the corrective action will achieve compliance with the applicable groundwater standards as well as how the closure plan will achieve the applicable groundwater standards.
- 845.710(d)(3) (Closure Alternatives) – Specify that groundwater modeling evaluate closure system performance and groundwater quality at least until groundwater protection standards are met, incorporating reasonably foreseeable declines in closure system performance.

Use of CCR During Closures

The proposed CCR rules indicate in Section 845.750(d), that additional waste may be placed in surface impoundment during closure for the purposes of grading and contouring the final cover system. This section goes to describe restrictions to the use of CCR for this purpose.

No amount of hydrogeologic characterization and engineering will render the active floodplain along a meandering river an acceptable location for permanent disposal of a utility's waste. The addition of CCR to such impoundments is equally unacceptable. Addition of CCR to a waste disposal area located in unstable areas, including floodplains, is essentially increasing the size, concentration, and duration of environmental and health impacts that will surely develop or continue far into the future. Closing and enlarging CCR containment structures on the 1% annual probability floodplain must be viewed as an unacceptable waste management practice that will facilitate contamination of waters of the United States and have potentially catastrophic results for future residents.

Addition of CCR during closure of unlined impoundments in contact with groundwater is simply adding contaminant mass to the source of groundwater contamination. The added waste would extend the duration over which contaminants can be released to the environment, may increase the concentration of released contaminants, and have the practical effect of limiting the range of remedial options available to address contamination. For these reasons I recommend adding a condition to Section 845.750(d) indicating that:

- Units that are lined or unlined, located on unstable areas (including floodplains), or that do not meet a revised requirement for 5 feet of unsaturated soils between the bottom of

[13] ClosureTurf (2018), Frequently Asked Questions. ClosureTurf claims "longevity over 100 years to half-life as proven by multiple independent evaluations."

waste and the highest seasonal zone of saturation are not eligible to receive additional CCR during closure.

Closure By Removal

Closure by removal is an effective and permanent remedy. Since the source of contamination is being removed there is no need for long term monitoring and site maintenance, and the property can be made available of other uses. Groundwater monitoring data from CCR removal projects that I am familiar with have shown surprisingly rapid reductions in groundwater contaminant concentrations during the removal process. It appears that lowering of the internal leachate elevations by dewatering processes may reduce the volume of leachate migrating from the unit well before the source materials are all removed. Once the contaminant source materials are removed, improvements to water quality are expected to continue to improve.

Real world confirmation that excavation and removal of coal ash from surface impoundments will improve groundwater quality has been generated in South Carolina. Electric utilities in South Carolina have committed to excavate ash from all impoundments in the state. Groundwater monitoring data and documents submitted by South Carolina Electric and Gas (SCE&G) on their Wateree Station (Wateree) and Santee Cooper submittals on their Grainger Generating Station (Grainger) provide clear examples of the beneficial impact that ash removal can have on groundwater quality. Arsenic is the primary ash constituent of concern to groundwater quality at each of these locations. Ash impoundments at these stations were closed by excavating ash, letting the ash dry (as necessary), and shipping the ash off-site for beneficial use and/or landfilling. The bottom and sides of the impoundments were over-excavated by a minimum of 1-foot to remove ash that may have penetrated into the surrounding materials.

Photograph of removal process taken during visit to the Wateree Station in South Carolina.

While complete removal of the ash was in process, some wells in the vicinity of the excavated areas at Wateree and Grainger showed rapid improvements in groundwater quality. Pursuant to an agreement with a local conservation group the project to completely remove ash from the Wateree Station commenced during the second half of 2012. The concentration of arsenic in monitoring well MW-11, located directly downgradient of the initial area of excavation in Ash Pond 1, had decreased from 690 ug/l in May 2012 to 56.4 ug/l in May 2017. The ash impoundment removal projects at the Wateree station were projected to require 8 years to complete.

Removal of ash from the Grainger Station was initiated in 2014. The concentration of arsenic in monitoring wells located downgradient of the initial excavation decreased from an April 2014 concentration of 1,098.2 ug/l in monitoring well GGSMW-10 to a concentration of 209 ug/l in March of 2017. Arsenic concentrations in monitoring wells GGSMW-3 and GGSMW-11 decreased from 901.5 and 401.8 ug/l in April 2014 to 250 and 207 ug/l in March 2017, respectively. The ash impoundment removal project at the Grainger station was originally projected to require 9 years to complete. Attachment 9 provides news articles describing the rapid reductions in groundwater contamination observed during waste excavation at South Carolina sites.

Groundwater contaminant measurements may vary from time period to time period during removal of ash due to changes made during the removal process. But the trend over time in improvements in groundwater quality in locations near areas excavated to date at these facilities provide real-world confirmation at these sites that excavation and beneficial re-use and/or landfilling of ash will decrease contaminant concentrations. Further, removal of the source of contamination is essential to stopping the continuing flow of contaminants into groundwater and connected surface waters.

Closure Progress Reporting

Corrective action and site closures never go completely smoothly, no matter how much advance planning is incorporated into the process. Easy and effective communication with IEPA and the public is needed in order to allow IEPA to monitor progress and evaluate the need for process revisions. The posted progress reports would also be a useful way to gain and maintain public acceptance and explain any unexpected activities or inconveniences that they might encounter. For this reason I suggest that the following addition to the list of Publicly Accessible Internet Site Requirements (Section 845.810):

- Quarterly progress reports must be posted demonstrate progress along the mutually agreed corrective action plan and schedule and identify unanticipated developments that arise during the course of the project.

5) The Duration of Post-Closure Care Period Must Reflect the Risk of the Closure

Unlike municipal solid waste, inorganic CCR does not biodegrade. CCR waste that is Capped-In-Place will remain in the unit and be capable of leaching contaminants into the groundwater at any time in the distant future that the cap begins to leak. Even the best caps will not last indefinitely. A cap can begin to leak through natural processes such as erosion, cap penetrations by vegetation and/or animals, or simply as the cap degrades with UV exposure and age. Damage to a cap can also happen through human activities, such as when people in pick-up trucks or on dirt bikes decide to turn the "big hill out where the old plant used to be" into a playground. Infiltration of significant water through the cap will generate leachate and resume environmental impacts. Capping CCR waste in place is essentially a process of shifting forward the environmental remediation costs associated with electricity production during our lifetimes to be paid by our grandchildren.

There are many examples of closed CCR waste sites that continue to contaminate groundwater for decades after closure. One example is the Yard 520 Landfill in Town of Pines, Indiana. Beginning in 1966, Yard 520 Landfill was utilized to dispose of CCR waste[14] from the Northern Indiana Public Service Company (NIPSCO) Michigan City Generating Station. CCR waste was accepted in the North Area of Yard 520 Landfill for 21 years, until 1987. A 2 ½ foot thick engineered clay cap was installed on the North Area in the mid-1990s. A Closure Certification Report on the North Area was issued in 1996.

In the early 2000s, EPA determined that high concentrations of boron and molybdenum detected in residential drinking water wells in Town of Pines were related to the North Area of Yard 520 Landfill. EPA and four potentially responsible parties (PRPs) entered into Administrative Order on Consent (AOC I) on January 24, 2003 that required the PRPs to extend municipal water service from Michigan City to the affected residences in Town of Pines.

In April 2004, 17 years after the last waste was accepted and 9 years after the Closure Certification Report was issued, EPA and the PRPs entered into AOC II that required the PRPs to conduct a Remedial Investigation and Feasibility Study (RI/FS) of the site. The Record of Decision (ROD) for the Yard 520 landfill RI/FS, signed in 2016, called for investigation of properties in Town of Pines to identify, excavate, and replace soils found to be above clean-up levels, phytoremediation of the groundwater plume, long-term groundwater monitoring, and land use controls on surrounding properties. Of particular importance to the current discussion is the requirement in the 2016 Yard 520 ROD for "Long-Term Groundwater Monitoring." Establishment of a Long Term Groundwater Monitoring program was included in the ROD that was signed approximately 29 years after the last waste was place in the landfill and 20 years after the site was certified to be capped and closed. The "Long-Term Groundwater Monitoring"

[14] Less than 5 percent of the materials disposed of in this landfill consisted of construction and demolition wastes generated from the steel making process.

required by the ROD is now beginning, 21 years after site closure and 30 years after waste acceptance was discontinued. The entire duration of groundwater monitoring at the Yard 520 should be expected to extend for 50 or more years.

Signed:

Dated: August 27, 2020

Attachment List

1. EPA, 1993, Criteria for Solid Waste Disposal Facilities, A Guide for Owners/Operators, EPA/530-SW-91-089, March 1993.
2. EPA, 2015, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,838, 67,838 and 67, 847 (November 3, 2015) (40 C.F.R. Part 423)
3. Geo-Hydro, Inc. Review of Closure Permit Application and Other Pertinent Materials, Plant Wansley Ash Pond 1, July, 2019
4.
    a. Glenn Thrush, Kendra Pierre-louis. "Florence's Floodwaters Breach Defenses at Duke Energy Plant, Sending Toxic Coal Ash Into River." *The New York Times*, The New York Times, 21 Sept. 2018.
    b. Brady Dennis, Steven Mufson. "Dam Breach Sends Toxic Coal Ash Flowing into a Major North Carolina River." The Washington Post, WP Company, 22 Sept. 2018.
    c. Knoblauch, Jessica A. "Along With Flooding, Hurricane Florence Unleashes Toxic Coal Ash." Earthjustice, 19 Nov. 2018.
5. Dynegy Midwest generation, 2020, 2019 Annual Groundwater Monitoring and Corrective Action Report, Baldwin Bottom Ash Pond, Baldwin Energy Complex, January 31, 2020.
6. Geo-Hydro, Inc. Review of Closure Permit Application and Other Pertinent Materials Plant Scherer Ash Pond 1, July, 2019
7. ClosureTurf (2018), ClosureTurf, A Predictable Benchmark of Performance.
8. ClosureTurf (2018), Frequently Asked Questions.
9.
    a. Fretwell, Sammy. "Arsenic Levels Decline in Pollution Tests at LR Coal Plant." The State, 1 Feb. 2016.
    b. Wren, David. "Santee Cooper's Coal Ash Removal Reducing Arsenic Levels." Post and Courier, The Post and Courier, 5 June 2016.

CERTIFICATE OF SERVICE

The undersigned, Jeffrey Hammons, an attorney, certifies that I have served by email the Clerk and by email the individuals with email addresses named on the Service List provided on the Board's website, available at https://pcb.illinois.gov/Cases/GetCaseDetailsById?caseId=16858, a true and correct copies of the **Pre-filed Testimony of Mark Hutson** and **Attachments** thereto before 5 p.m. Central Time on August 27, 2020. The number of pages in the email transmission is 240 pages.

Respectfully Submitted,

/s/Jeffrey T. Hammons____________

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The following are attachments to the testimony of Mark Hutson.

ATTACHMENT 1

United States
Environmental Protection
Agency

Solid Waste
and Emergency Response
(OS-305)

EPA/530-SW-91-089
March 1993

EPA

Criteria for Solid Waste Disposal Facilities

A Guide for Owners/Operators

Owners/operators must set up a system to ensure that hazardous wastes are kept out of municipal landfills.

To make waste management more effective, federal, state, tribal, and local governments are adopting an integrated approach to waste management. This strategic approach involves a mix of three waste management techniques: 1) decreasing the amount and/or toxicity of waste that must be disposed of by producing less waste to begin with (source reduction); 2) increasing recycling of materials such as paper, glass, steel, plastic, and aluminum, thus recovering these materials rather than discarding them; and 3) providing safer disposal capacity by improving the design and management of incinerators and landfills.

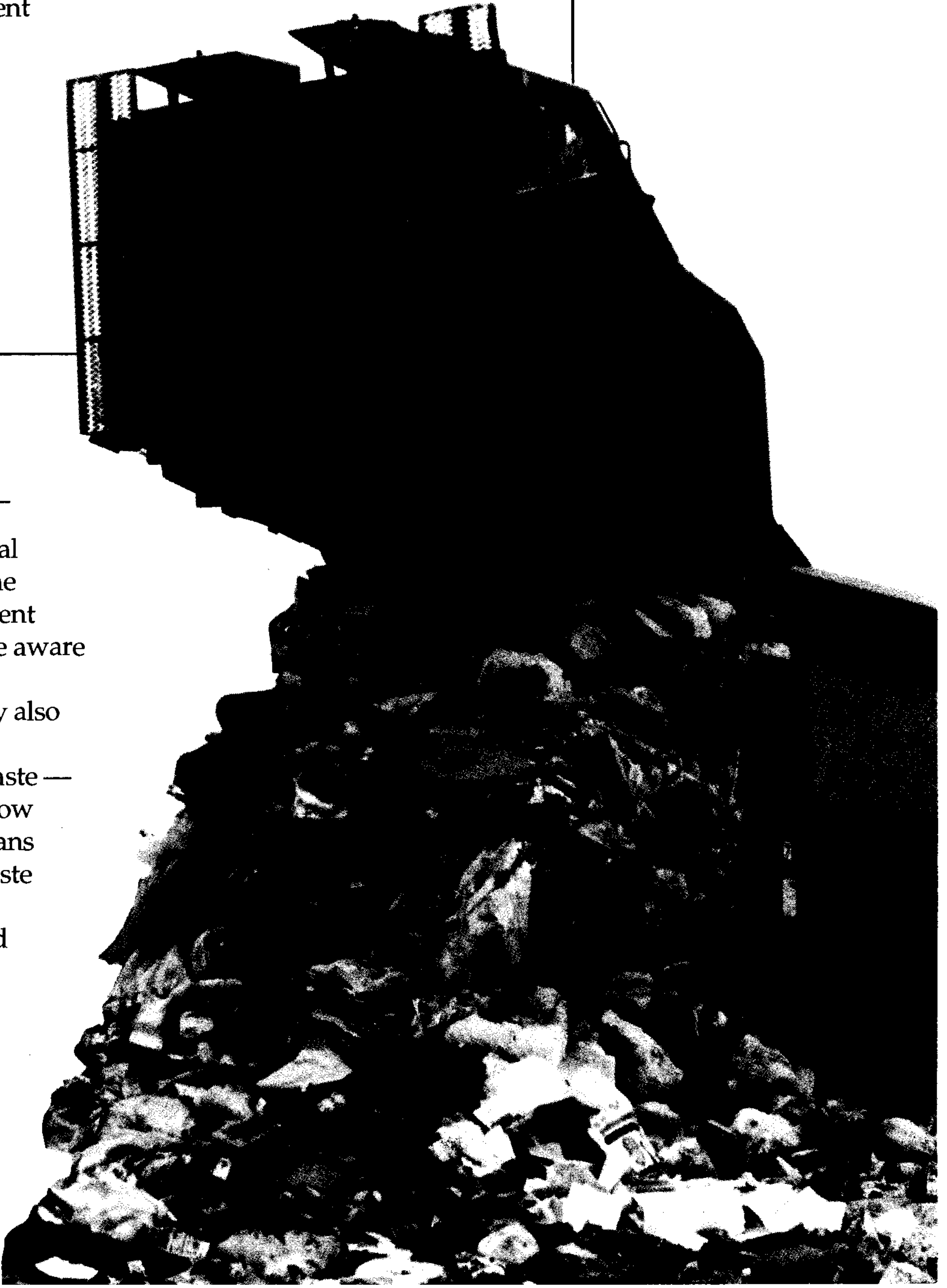
Source reduction and recycling will keep a lot of waste out of municipal landfills, but we still need landfills. The challenge is to make them safe in order to protect our communities and our environment—and that requires a strong partnership of federal, state, and tribal governments; industry; and citizens.

EPA's continuing mission is to minimize the risks from landfills. The criteria described in this booklet are an important part of this effort. They establish minimum national standards for landfill design, operation, and management that will enhance landfill safety and boost public confidence in landfills as a component of a workable integrated waste management system.

This booklet summarizes the provisions of the U.S. Environmental Protection Agency's (EPA's) Municipal Solid Waste Landfill (MSWLF) Criteria. It discusses the major requirements of these regulations, who is required to comply and when, how the rule will be implemented and enforced, and where to obtain more information. States and Indian tribes are expected to adopt these federal standards and implement the regulations through their own permit programs. This booklet highlights the increased flexibility given to states and tribes that develop EPA-approved programs.

This booklet provides only an overview of the federal regulations. Readers affected by them should refer to the actual regulations, which are published in Volume 40 of the *Code of Federal Regulations*, Part 258 (see the *Federal Register*, October 9, 1991, 56FR50978). The Agency encourages landfill owners/operators to work with their respective state or tribal authorities, since state and tribal programs may have different requirements.

Although written primarily for owners/operators of municipal solid waste landfills, this booklet also will be useful for others, including state and tribal government officials, who are responsible for implementing the regulations.



Introduction

The problems caused by municipal solid waste landfills have become a source of public concern in recent years. As Americans have become more aware of the potential threat to health and the environment from toxic substances, they also have become more concerned about the generation and management of solid waste — sometimes to the point of refusing to allow new landfills near their homes. Americans are generating more municipal solid waste each year, but available landfill space is declining. In 1990, Americans generated over 195 million tons of municipal solid waste, and the annual amount is expected to increase to more than 220 million tons by 2000.

The Purpose of These Regulations

Historically, landfills have been associated with some significant problems, including ground-water contamination, which partly explains the public's resistance to new facilities.

Ground-water contamination. Nearly half the country's population draws its drinking water from aquifers and other ground-water bodies. Ground water also is used extensively for agricultural, industrial, and recreational purposes. Landfills can contribute to the contamination of this valuable resource if they are not designed to prevent waste releases into ground water or detect them when they occur. Cleaning up contaminated ground water is a long and costly process and in some cases may not be totally successful. Affected communities often bear both the cleanup costs and the expense of providing other sources of potable water. By adopting a philosophy of prevention, the regulations' improved design standards will protect ground water.

Difficulties in landfill siting. The problem of managing the increased volume of municipal solid waste is compounded by rising public resistance to siting new landfills. The regulations are designed to ensure that new or expanded landfills do not contaminate ground water and thus become community burdens. As a result, they protect the intrinsic value of ground water and can help avert the pressures associated with landfills that can drive down property values.

Specific prevention measures written into the regulations include location restrictions, operating and design criteria, and requirements for final cover and post-closure care. The regulations also require ground-water monitoring to detect any releases of contaminants from landfills. Corrective action and financial assurance provisions ensure immediate and effective responses to such releases.

Some Definitions Under the Regulations

Municipal solid waste landfill (MSWLF): A discrete area of land or an excavation that receives household waste, and that is not a land application unit, surface impoundment, injection well, or waste pile, as those terms are defined in the law. (Household waste includes any solid waste, including garbage, trash, and septic tank waste derived from houses, apartments, hotels, motels, campgrounds, and picnic grounds.) An MSWLF unit also may receive other types of wastes as defined under Subtitle D of the Resource Conservation and Recovery Act (RCRA), such as commercial solid waste, nonhazardous sludge, small quantity generator waste, and industrial solid waste. Such a landfill may be publicly or privately owned. An MSWLF unit can be a new unit, an existing unit, or a lateral expansion (see definitions below).

Existing unit: A municipal solid waste landfill unit that is receiving solid waste as of October 9, 1993. Waste placement in existing units must be consistent with past operating practices or modified practices to ensure good management.

Lateral expansion: A horizontal expansion of the waste boundaries of an existing unit; does not include expansion in the vertical dimension.

New unit: Any municipal solid waste landfill unit that has not received waste prior to October 9, 1993.

Small landfill: A landfill serving a community that disposes of less than 20 tons of municipal solid waste per day, averaged yearly.

EPA has carefully considered the impacts of the regulations on local governments. Where possible, EPA has written the regulations to allow flexibility in both the technical requirements and their implementation. For example, the regulations provide relief from the more costly requirements for certain small landfills. Moreover, states and tribes with EPA-approved landfill permitting programs are given the opportunity to provide considerable flexibility in applying all major components of the landfill criteria, so that site-specific conditions can be considered in such areas as design and ground-water monitoring.

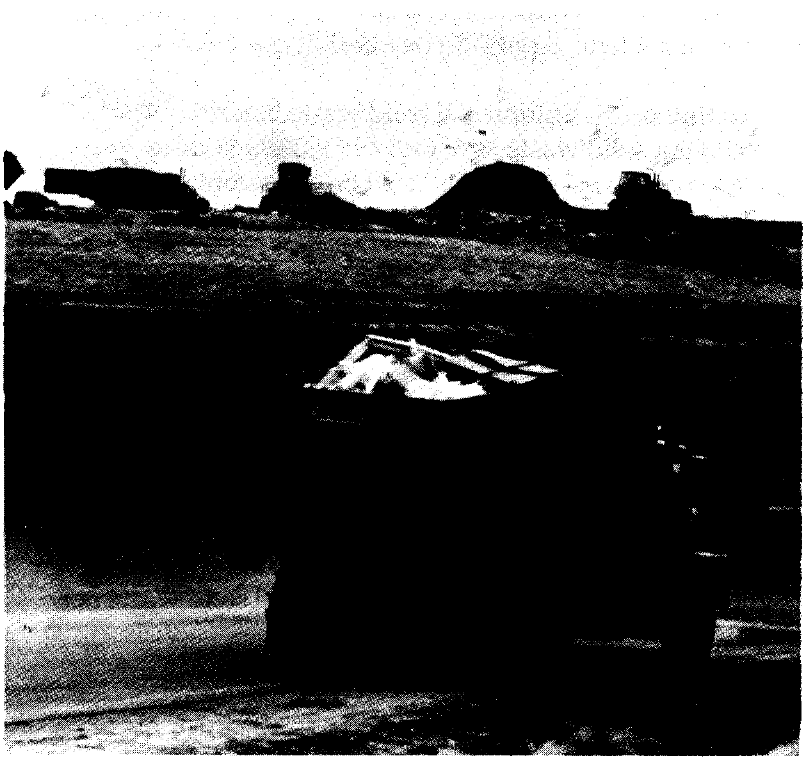
Who Is Covered?

Landfills receiving waste on or after October 9, 1993, must comply with the regulations.

The regulations apply to owners/operators of all municipal solid waste landfills that receive waste on or after October 9, 1993. Landfills that stop accepting waste between October 9, 1991, and October 9, 1993, need only comply with the requirements for final cover (see page 16). Landfills that stopped accepting waste before October 9, 1991, do not need to comply with these regulations.

The regulations apply to landfills that accept household waste, which means any solid waste (including garbage, trash, and sanitary waste in septic tanks) derived from households (including single and multiple residences, hotels and motels, bunkhouses, ranger stations, crew quarters, campgrounds, picnic grounds, and day-use recreation areas). They do not apply to units (including landfills, surface impoundments, waste piles, and land application units) that accept only industrial nonhazardous waste (e.g., construction/demolition landfills). (Owners/operators of these units would be required to comply with the provisions of 40 CFR Part 257.)

As mentioned, owners/operators of certain small landfills may be eligible for exemption from the regulations governing design, ground-water monitoring, and corrective action. See the section entitled "Exemptions for Small Landfills," page 5.



When Do the Requirements Apply?

The requirements concerning *location restrictions, design criteria* (new and lateral expansion units only), *operating criteria*, and *closure/post-closure care* are effective October 9, 1993. *Ground-water monitoring and corrective action requirements* are effective three, four, or five years after October 9, 1991, depending on a unit's proximity to drinking water intakes (see sidebar, page 15). The *financial assurance requirements* are effective April 9, 1994.

These dates reflect the requirements of the federal MSWLF criteria. Contact your state or tribal authority to determine specific state/tribal effective dates.

Implementation of the Regulations: Federal, State, Tribal, and Owner/Operator Responsibilities

Implementation by approved states and Indian tribes

States and tribes are entitled to develop their own permitting programs incorporating the federal landfill criteria to ensure that owners/operators are complying. States and tribes also may establish requirements that are more stringent than those set by the federal government. EPA's role is to review and approve these programs.

EPA is developing the State/Tribal Implementation Rule, which will delineate the requirements for receiving EPA approval. For permit programs to be considered adequate, a state or tribe must have the capability of issuing permits or some other form of prior approval, and must establish conditions requiring owners/operators to comply with the landfill regulations. A state or tribe must also be able to ensure compliance through monitoring and enforcement actions and must provide for public participation.

By securing approval for its program, a state or tribe has the opportunity for more flexibility and discretion in implementing the criteria according to local needs and conditions. Owners/operators located in a jurisdiction with an approved program may benefit from this potential flexibility, which extends to all parts of the regulations (see box, page 6).

Implementation in states/tribes without approved programs

EPA expects that although most states will be approved by the effective date of the rule, some simply may not apply. In these cases, owners/operators are required to implement the federal regulations. Each owner/operator must document compliance and supply this documentation to the state or tribe on request. Owners/operators must comply with state/tribal requirements.

Citizen roles

While state, tribal, and local governments are responsible for ensuring compliance with their waste programs, private citizens play an important role, too. Individuals can help ensure that facilities comply with state or tribal rules and regulations through such activities as participating in any public meetings regarding landfill siting and permit issuance, and working closely with their responsible state, tribal, and local officials. Citizens also have the right to sue landfill owners/operators who are not in compliance with the federal regulations.

Exemptions for Small Landfills

Approximately 6,000 municipal landfills are potentially subject to the criteria. Quite a few — nearly 50 percent — are defined as "small" landfills, meaning they receive an average of no more than 20 tons of municipal solid waste per day (figured annually). These landfills generally serve communities of fewer than 10,000 people.

The landfill design, ground-water monitoring, and corrective action provisions required under the criteria are likely to be expensive. Small communities might be unable to spread these costs among many users, thereby leading to significant increases in per-capita disposal assessments.

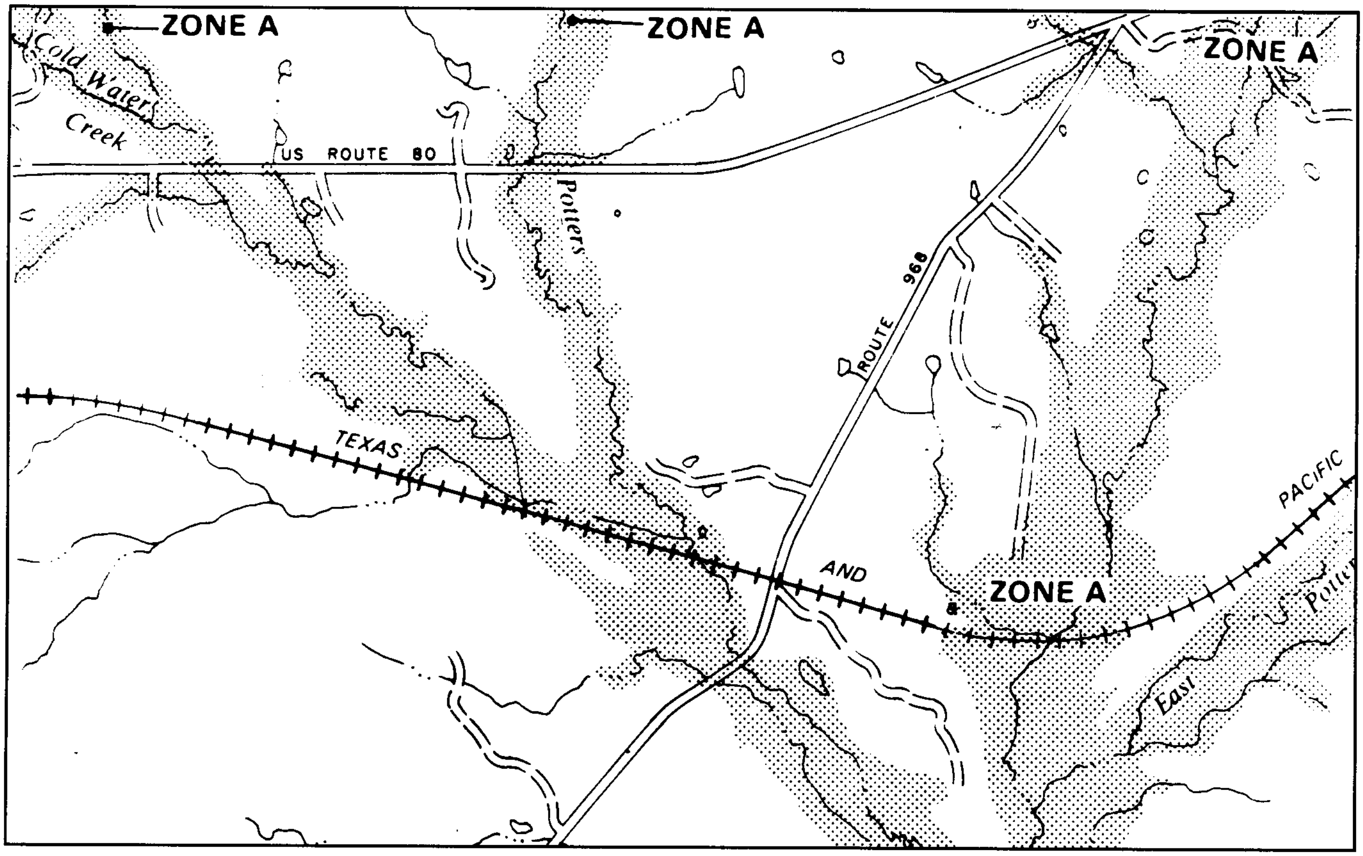
The regulations are designed to provide the opportunity for some relief from the more costly requirements without compromising human health or the environment. An owner/operator of a small landfill may be exempted from the design, ground-water monitoring, and corrective action requirements under two circumstances:

1) There is no evidence of ground-water contamination, the community has no practical waste management alternative, and the landfill is located in an area that receives less than 25 inches of precipitation annually.

2) There is no evidence of ground-water contamination and the community undergoes an annual interruption of surface transportation, lasting at least three consecutive months, that prevents access to a regional facility. This exemption is less widespread since, for example, it may be more applicable to certain communities in rural Alaska.

These exemptions are available to qualifying small landfills in all states or tribal jurisdictions, even those without EPA-approved permitting programs, providing the state or tribal program does not restrict the exemption.

Some small landfills serving small communities, such as this one in the dry, western United States, may qualify for exemption from some of the requirements.



Special restrictions apply to landfills sited in floodplains, indicated here as the shaded area.

(The exemptions supplement the flexibility in implementing the regulations given all communities in states and tribal jurisdictions with approved programs. See page 6.)

Owners/operators qualifying for exemptions must show why they qualify and include the documenting information in their operating records. Owners/operators are also required to comply with all other MSWLF regulations, including the location, operation, closure and post-closure, and financial assurance provisions.

If the owner/operator of an exempt facility learns of ground-water contamination at the site, the exemption is no longer applicable and the owner/ operator must comply with the requirements for design, ground-water monitoring, and corrective action.

Complying With the Regulations

The regulations describe six categories of criteria for municipal solid waste landfills:

1) Location
2) Operation
3) Design
4) Ground-water monitoring and corrective action
5) Closure and post-closure care
6) Financial assurance

Owners/operators are responsible for reviewing the criteria to determine which of the provisions apply to their landfill(s). (Owners/operators should refer to EPA's *Technical Manual for Solid*

Waste Disposal Facility Criteria for details.) They should also bear in mind that state or tribal programs might include provisions that do not mirror the federal provisions discussed below. Owners/operators are therefore encouraged to work with their state and tribal regulators in complying with the regulations.

Location Criteria Summary

Location	Applicability*	Closure If Demonstration Cannot Be Met?
Airport Safety	N,E,L	Yes
Floodplains	N,E,L	Yes
Wetlands	N,L	No
Fault Areas	N,L	No
Seismic Impact Zones	N,L	No
Unstable Areas	N,E,L	Yes

*(N=New, E=Existing, L=Lateral Expansion)

Location

There are six location restrictions that apply to municipal landfills. Owners/operators must demonstrate that their units meet the criteria and keep the demonstration documents in the facility operating record.

If an owner/operator cannot show compliance with the airport safety, floodplain, or unstable-area provisions, the unit must be closed by October 9, 1996. However, states and tribes with EPA-approved programs can extend this deadline by as much as two years when no alternative waste management capacity exists and there is no immediate threat to human health and the environment.

Restricted areas include:

1. Airports

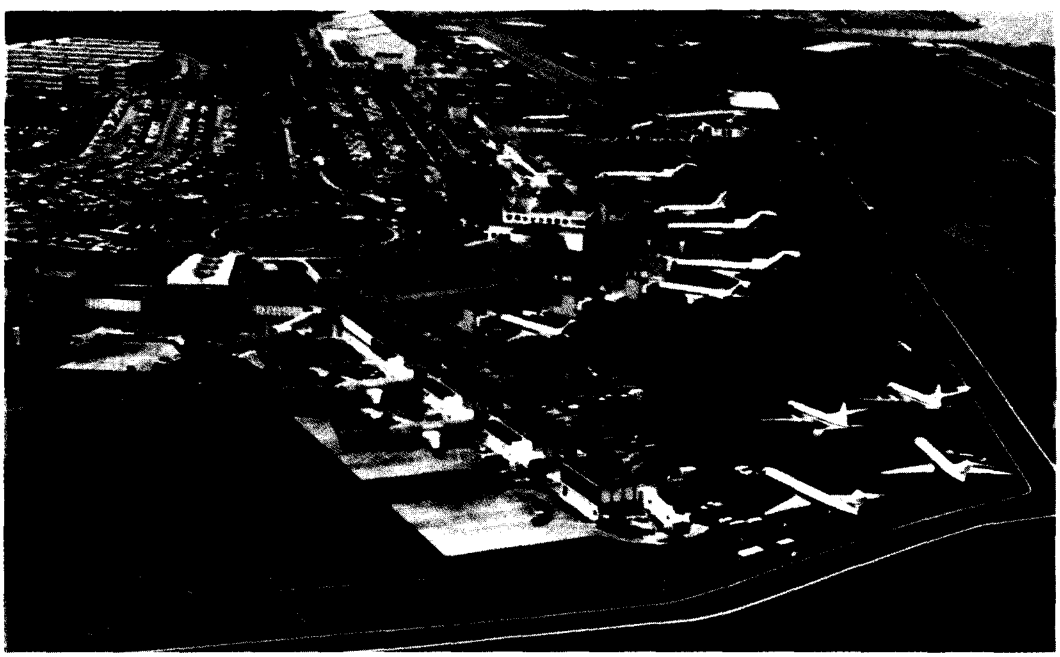
The owner/operator of a municipal landfill located within 10,000 feet of the end of any airport runway used by turbojet aircraft, or within 5,000 feet of any airport runway used only by piston-type aircraft, must demonstrate that the unit does not pose a bird hazard.

If an owner/operator plans to build a new unit or laterally expand an existing unit within 5 miles of any airport, the airport and the Federal Aviation Administration must be notified.

2. Floodplains

Units located in 100-year floodplains cannot restrict the flow of the 100-year flood, reduce the temporary water storage capacity of the floodplain, or allow the washout of solid waste.

The regulations impose special requirements on landfills near airports to prevent compromises to air traffic safety.



3. Wetlands

In general, owners/operators of new or expanding municipal landfills may not build or expand in wetlands. However, states or tribes with EPA-approved permitting programs can make exceptions for units able to show:

- No siting alternative is available.
- Construction and operation will not (1) violate applicable state/tribal regulations on water quality or toxic effluent; (2) jeopardize any endangered or threatened species or critical habitats; or (3) violate protection of a marine sanctuary.
- The unit will not cause or contribute to significant degradation of wetlands.
- Steps have been taken to achieve no net loss of wetlands by avoiding effects where possible, minimizing unavoidable impacts, or making proper compensation (e.g., restoring damaged wetlands or creating man-made wetlands).

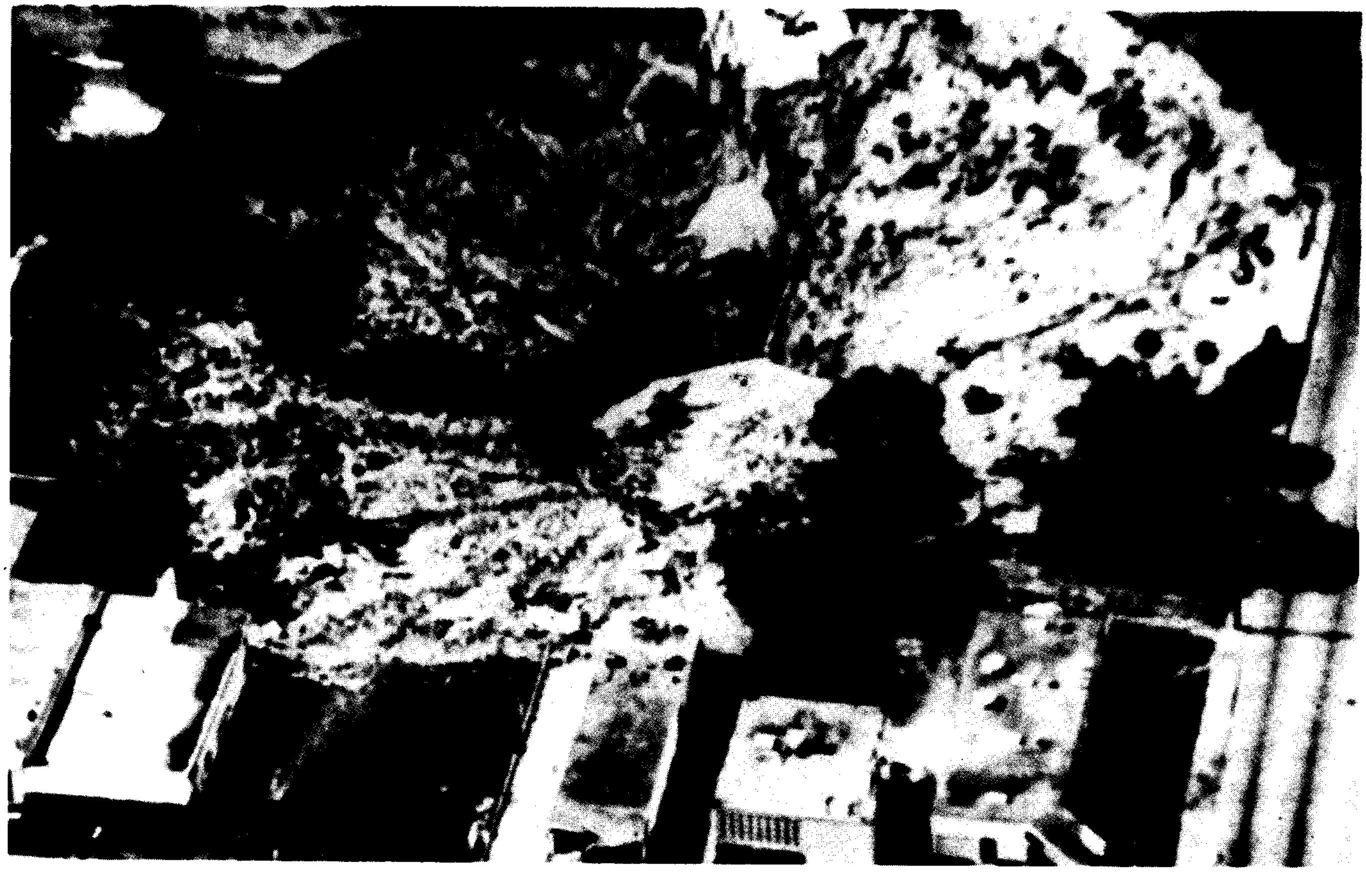
4. Fault areas

New units or lateral expansions are generally prohibited within 200 feet of fault areas that have shifted since the last Ice Age. However, the director of an approved state or tribal program may allow an alternative setback distance of less than 200 feet if the owner/operator can show that the unit will maintain structural integrity in the event of a fault displacement.

5. Seismic impact zones

When a new or laterally expanding unit is located in a seismic impact zone, its containment structures (liners, leachate collection systems, surface-water control systems) must be designed to resist the effects of ground motion due to earthquakes.

Landfills may not be built in unstable areas prone to landslides, mudslides, or sinkholes, such as the one shown here.



6. Unstable areas

All owners/operators must show that the structure of their units will not be compromised during "destabilizing events," including:

- Debris flows resulting from heavy rainfall.
- Fast-forming sinkholes caused by excessive ground-water withdrawal.
- Rockfalls set off by explosives or sonic booms.
- The sudden liquification of the soil after a long period of repeated wetting and drying.

Operation

All owners/operators must comply with the requirements for proper management of municipal solid waste landfills. These cover a range of procedures, including:

1. Receipt of regulated hazardous waste

The owner/operator must set up a program to detect and prevent disposal of regulated quantities of hazardous wastes and polychlorinated biphenyl (PCB) wastes. The program must include procedures for random inspections, record keeping, training of personnel to recognize hazardous and PCB wastes, and notification of the appropriate authorities if such waste is discovered at the facility.

2. Cover material

The owner/operator must cover disposed solid waste with at least 6 inches of earthen material at the end of each operating day to control vectors, fires, odors, blowing litter, and scavenging. An approved state or tribe may allow an owner/operator to use an alternative cover material or depth, and/or grant a temporary waiver of the cover requirement (if local climate conditions make such a requirement impractical).

3. Vectors

The owner/operator is responsible for controlling vector populations. Vectors include any rodents, flies, mosquitoes, or other animals or insects capable of transmitting disease to humans. Application of cover at the end of each operating day generally controls vectors.

4. Explosive gases

The owner/operator must set up a program to check for methane gas emissions at least every three months. If the limits specified in the regulations are exceeded, the owner/operator must immediately notify the state/tribal director (that is, the official in the state or area responsible for implementing the landfill criteria) and take immediate steps to protect human health and the environment. The owner/operator also must develop and implement a remediation plan within 60 days. States and tribal jurisdictions with approved programs may alter this interval.

5. Air quality

Open burning of waste is not permitted except for infrequent burning of agricultural waste, silvicultural waste, land-clearing debris, diseased trees, or debris from emergency clean-up operations. Owners/operators must comply with the applicable requirements of their State Implementation Plans for meeting federal air quality standards.

6. Access

The owner/operator must control public access to prevent illegal dumping, unauthorized vehicular traffic, and public exposure. Artificial and/or natural barriers may be used to control access.

Owners and operaters must ensure that each day's waste is covered to control litter and disease-bearing vermin.

7. Storm water run-on/run-off

The owner/operator must build and maintain a control system designed to prevent storm waters from running on to the active part of the landfill. The run-on control system must be able to handle water flows as heavy as those expected from the worst storm the area might undergo in 25 years.

The owner/operator also must build and maintain a surface water run-off control system that can collect and control, at a minimum, the surface water volume that results from a 24-hour, 25-year storm. Run-off waters must be managed according to the requirements of the Clean Water Act, particularly with regard to the restrictions on the discharge of pollutants into water bodies and wetlands.

8. Surface water protection

All landfills must be operated in a way that ensures they do not release pollutants that violate the Clean Water Act, which protects surface waters.

9. Liquids

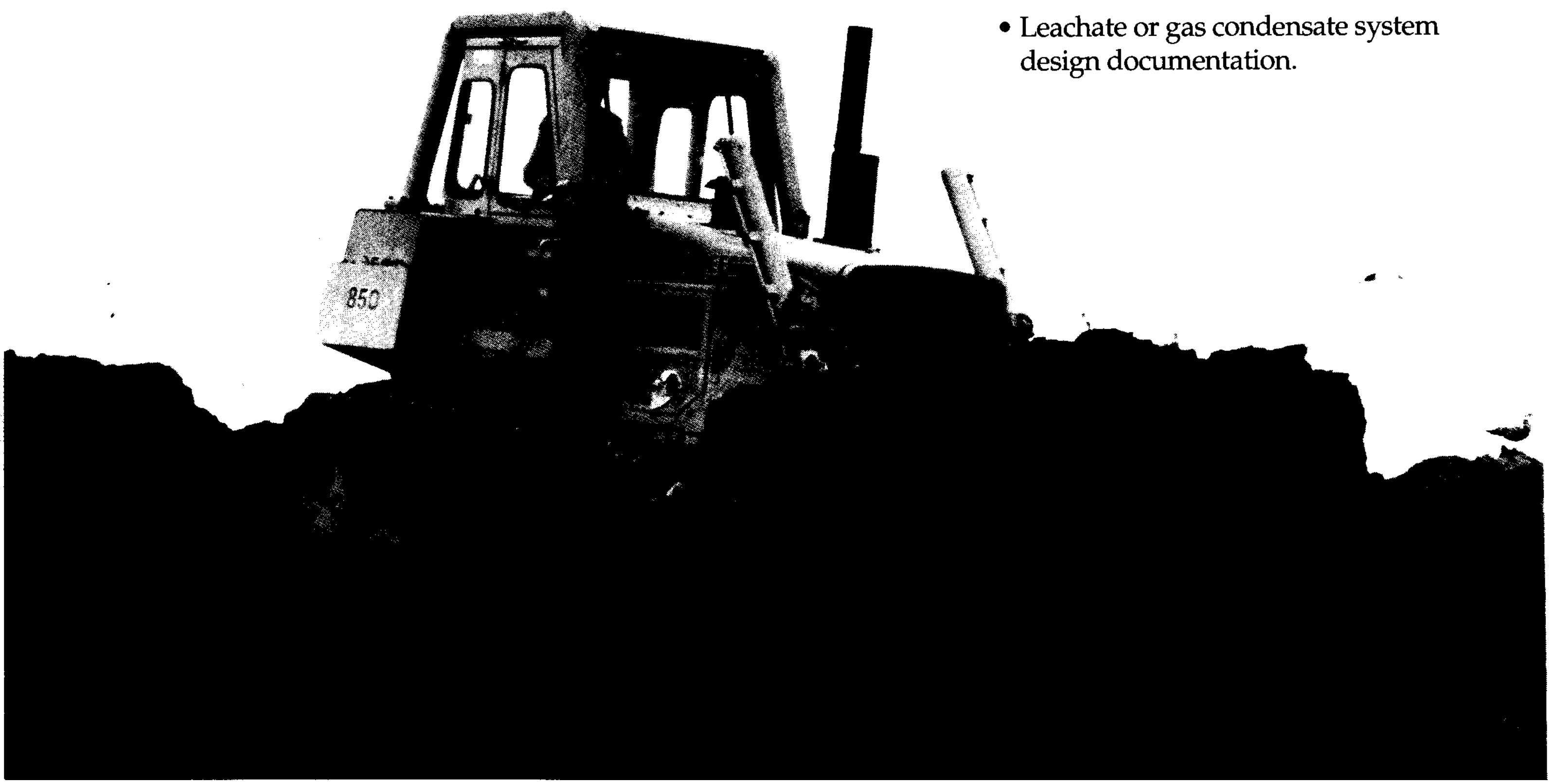
A landfill cannot accept bulk or noncontainerized liquid waste unless (1) the waste is nonseptic household waste, or (2) it is leachate or gas condensate that is recirculated to the landfill, and the unit is equipped with a composite liner and leachate collection system as described below under "Design."

Containers of liquid waste may be placed in the landfill only if the containers: (1) are similar in size to those typically found in household waste, such as cleaning, automotive, or home-improvement products (i.e., containers such as 55-gallon drums are excluded); (2) are designed to hold liquids for use other than storage; or (3) hold only household waste (containers collected in routine pickups from households).

10. Record-keeping

Owners/operators are required to keep certain documents in or near the facility, including:

- Location restriction demonstrations.
- Procedures for excluding hazardous waste.
- Gas monitoring results.
- Leachate or gas condensate system design documentation.



- Ground-water monitoring and corrective action data and demonstrations.
- Closure and post-closure plans.
- Cost estimates and financial assurance documentation.

Design

The criteria for landfill design apply only to new units and lateral expansions. (Existing units are not required to retrofit liner systems.) The criteria give owners/operators two basic design options.

First, in states and tribal areas with EPA-approved programs, owners/operators may build their landfills to comply with a design approved by the state/tribal director. In approving the design, the director must ensure that it meets the EPA performance standard, i.e., that Maximum Contaminant Levels (MCLs) will not be exceeded in the uppermost aquifer at a "relevant point of compliance." This point is determined by the approved-state/tribal director, but it must be no farther than 150 meters from the landfill unit boundary and on land owned by the landfill owner. (EPA has already set MCLs for a number of solid waste constituents; see table.)

Maximum Contaminant Levels
(as of October 9, 1991)

Chemical	MCL (mg/l)
Arsenic	0.05
Barium	1.0
Benzene	0.005
Cadmium	0.01
Carbon tetrachloride	0.005
Chromium (hexavalent)	0.05
2,4-Dichlorophenoxy acetic acid	0.1
1,4-Dichlorobenzene	0.075
1,2-Dichloroethane	0.005
1,1-Dichloroethylene	0.007
Endrin	0.0002
Fluoride	4
Lindane	0.004
Lead	0.05
Mercury	0.002
Methoxychlor	0.1
Nitrate	10
Selenium	0.01
Silver	0.05
Toxaphene	0.005
1,1,1-Trichloromethane	0.2
Trichloroethylene	0.005
2,4,5-Trichlorophenoxy acetic acid	0.01
Vinyl chloride	0.002

In reviewing these performance-based designs, approved states and tribes also must consider other factors, such as the hydrogeologic characteristics of the facility and surrounding land, the local climate, and the amount and nature of the leachate.

The second option is a design developed by EPA that consists of a composite liner and a leachate collection system. In general, landfills in states or tribal jurisdictions without EPA-approved programs must use this design. The composite liner system combines an upper liner of a synthetic flexible membrane and a lower layer of soil at least 2 feet thick with a hydraulic conductivity of no greater than 1×10^{-7} cm/sec. The leachate collection system must be designed to keep the depth of the leachate over the liner to less than 30 centimeters.

The criteria also provide an option for owners/operators in nonapproved states or tribal jurisdictions to use the performance standard (rather than the EPA design described above), providing that *both* of the following conditions are met:

- EPA does not promulgate a State/Tribal Implementation Rule by October 9, 1993.
- The state or tribe determines that the alternative design meets the

performance standard in the federal criteria; the state or tribe petitions EPA to review this determination; and EPA does not deny the determination within 30 days.

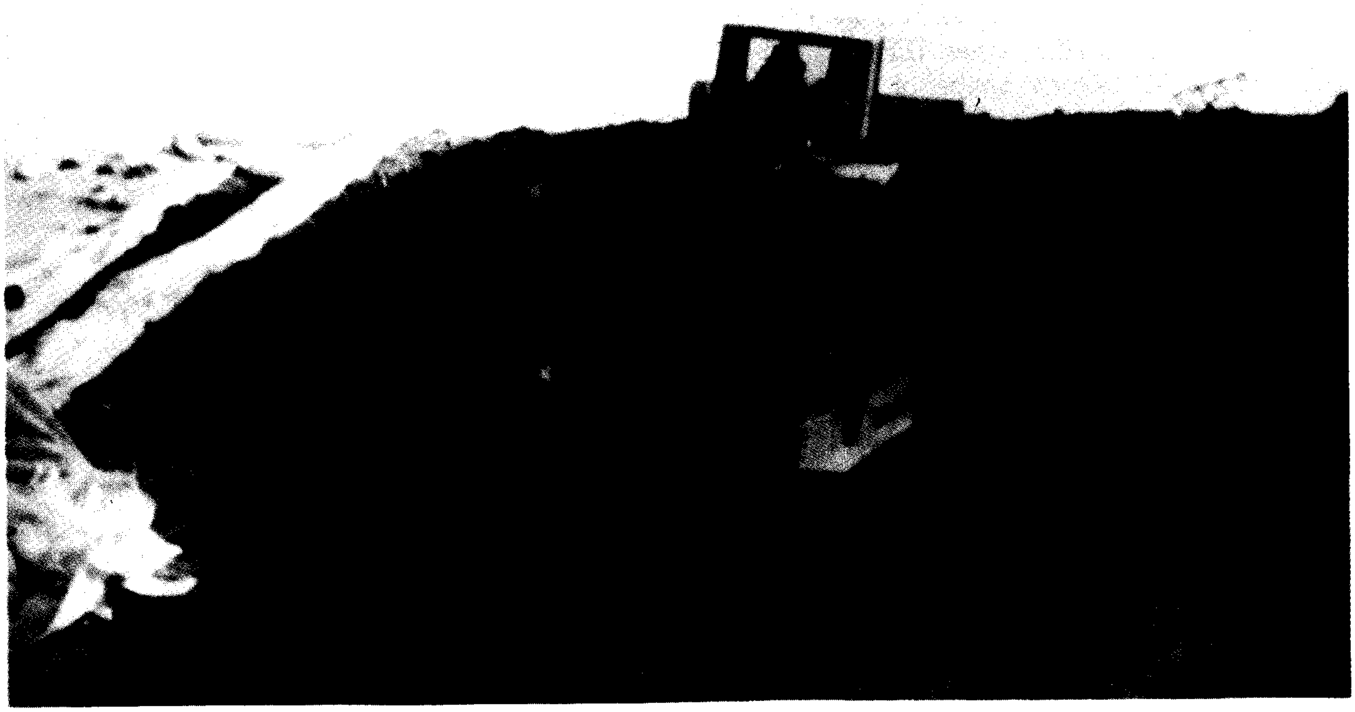
Ground-Water Monitoring and Corrective Action

This section sets criteria for ground-water monitoring systems, programs for sampling and analysis of ground water, and corrective action as necessary to ensure that human health and the environment are protected. Here, as with the other provisions in the federal criteria, approved states and tribes may adopt programs with requirements that are more stringent than the federal criteria. Again, owners/operators are encouraged to work closely with their states or tribes.

Ground-water monitoring systems

Generally, ground-water monitoring must be conducted at all MSWLF units. Owners/operators must install enough ground-water monitoring wells in the appropriate places to accurately assess the quality of the uppermost aquifer (1) beneath the landfill before it has passed the landfill boundary (to determine background quality) and (2) at a relevant point of compliance (down-gradient). Owners/operators should consider the specific characteristics of the sites when establishing their monitoring systems, but the systems must be certified as adequate by a qualified ground-water scientist or the director of an EPA-approved state/tribal program.

In approved states and tribal jurisdictions, an owner/operator may be able to obtain a variance from the ground-water monitoring requirements if the owner/operator can demonstrate that the landfill is located over a geologic structure that will prevent hazardous constituent migration to the ground water. The demonstration must show that no migration of constituents from the unit will occur during the unit's life, including the closure and post-closure care period.



Performance of a landfill cover must meet certain federal minimum criteria.

Detection and assessment monitoring programs

States and tribes with EPA-approved programs have the flexibility to design ground-water monitoring programs that are well-suited to the landfills operating in their area, and that may therefore differ from the federal program. In states/tribes without an approved permit program, owners/operators must follow the federal regulations describing detection and assessment monitoring.

During detection monitoring, owners/operators must take ground-water samples and analyze them for specific constituents (as defined in the federal regulations or by the director of an approved state/tribal program). Under the federal regulations, sampling and analysis must be conducted at least twice a year. Approved state/tribal programs may set alternative frequencies, but sampling and analysis must be done at least annually. If significant ground-water contamination is detected, owners/operators may seek to demonstrate that the results are due to contamination from other sources, sampling error, or natural variation in ground-water quality. Otherwise, owners/operators must notify the appropriate state/tribal official and begin assessment monitoring.

The purpose of assessment monitoring is to determine the nature and extent of ground-water contamination. During assessment monitoring, ground-water must be analyzed both for constituents detected initially and for other constituents (defined in the federal criteria or by the director of an approved state/tribal program). States and tribes with EPA-approved programs specify the frequency for sampling and analysis conducted during assessment monitoring. In nonapproved states and tribes, the frequency is specified in the federal regulations. As in detection monitoring, if ground-water analysis shows significant contamination, owners/operators might be able to make the determination that the landfill is not the source of the contamination. If the owner/operator cannot make this determination, then the ground water must be cleaned up (see "Corrective Action" below). In EPA-approved states and tribes, it must be cleaned up to levels specified by the state/tribal director; in nonapproved states and tribes, contamination must not exceed federal limits set for drinking water quality or background levels.

The federal ground-water monitoring requirements are more complex and technical than described here. A thorough explanation of the regulations can be found in EPA's *Technical Manual for Solid Waste Disposal Facility Criteria.*

Schedule for Implementing Ground-Water Monitoring

An EPA-approved state or tribe can set its own schedule, provided at least 50 percent of all the state's or tribe's units comply by October 9, 1994, and all are in compliance by October 9, 1996.

If a state or tribe has not been approved by EPA, owners/operators must comply with the following schedule for installing ground-water monitoring systems:

- If a site is less than 1 mile in any direction from a drinking water intake (whether surface or ground-water), by October 9, 1994.
- If the site is farther than 1 mile but less than 2 miles, by October 9, 1995.
- If the site is more than 2 miles, by October 9, 1996.

New units must install monitoring systems prior to accepting any waste.

Some owners/operators may choose to install leachate collection systems, such as the one shown here. These systems are designed to collect any fluids that seep down through the landfill. The fluids can be recycled in the landfill or treated for disposal elsewhere.

Ground-water monitoring regulations in states and tribes with EPA-approved programs may differ somewhat from the federal regulations. Landfill owners/operators conducting ground-water monitoring in nonapproved states and tribes must comply with the federal regulations in addition to their state's or tribe's regulations. In all cases, the owner/operator is encouraged to work with his or her state or tribe to ensure compliance with all applicable regulations.

The corrective action program

Cleaning up ground water requires corrective action. The owner/operator must assess corrective measures and select the appropriate one(s). During corrective action, the owner/operator must continue ground-water monitoring in accordance with the assessment monitoring program.

While evaluating potential remedies, the owner/operator must hold a public meeting to discuss them. Once the remedy has been selected, the owner/operator is responsible for carrying it out. During this period, a ground-water monitoring program must be established to measure the effectiveness of the remedy. The owner/operator must continue corrective action until compliance with the clean-up standard has been met for three consecutive years, although the director of an approved state or tribal program may specify a different period.

Closure and Post-Closure Care

The criteria establish specific standards for all owners/operators to follow when closing a landfill and setting up a program of monitoring and maintenance during the post-closure period. The owner/operator must enter the closure and post-closure plans into the landfill's operating records by October 9, 1993, or by the initial receipt of waste, whichever is later.

Owners/operators of landfills that stop receiving waste between October 9, 1991, and October 9, 1993, must install final covers that meet the federal criteria within six months of the last receipt of waste. Here again, owners/operators should work with their state or tribal program officials to ensure that all applicable closure requirements are considered.

The final cover must be designed and constructed to have a permeability less than or equal to the bottom liner system or natural subsoils, or a permeability no greater than $1x10^{-5}$ cm/sec, whichever is lower. Thus, the regulation is in the form of a performance standard that must be achieved by the owner/operator.

The final cover must be constructed of an infiltration layer composed of a minimum of 18 inches of earthen material to minimize the flow of water into the closed landfill. The cover must also contain an erosion layer to prevent the disintegration of the cover. The erosion layer must be composed of a minimum of 6 inches of earthen material capable of sustaining plant growth.

When a landfill's bottom liner system includes a flexible membrane or synthetic liner, the addition of a flexible liner in the infiltration layer cover will generally be the only design that will allow the final cover design to achieve a permeability less than or equal to the bottom liner.

The director of an approved state or tribe may approve an alternative final cover design that achieves an equivalent reduction in infiltration and protection from erosion as the design described above.

For 30 years after closure, the owner/operator is responsible for maintaining the integrity of the final cover, monitoring ground water and methane gas, and continuing leachate management. (Approved states/tribes may vary this interval.)

Closing a Landfill — and Beyond

Owners/operators must follow certain procedures when closing a municipal landfill, including the following:

- The state or tribe must be notified prior to closure.
- A closure plan must be prepared.
- The final cover must consist of at least 18 inches of earthen material of a specified permeability, with an erosion layer at least 6 inches thick. (An approved state/ tribe may allow an alternative cover design.)
- An independent certified engineer must certify that closure was conducted in accordance with the plan.
- The deed of property must note that the property was used as a landfill and that future use is restricted.

For 30 years following closure (or an alternative period designated by an approved state or tribe), owners/operators are responsible for maintaining the integrity of the final cover, continuing to monitor ground water and methane, and continuing leachate management.

Financial Assurance

All units except those owned or operated by state or federal government entities must comply with the financial assurance criteria, which are effective April 9, 1994.

The owner/operator must demonstrate financial responsibility for the costs of closure, post-closure care, and corrective action for known releases. This requirement can be satisfied by the following mechanisms:

- Trust fund with a pay-in period.
- Surety bond.
- Letter of credit.
- Insurance.
- Guarantee.
- State assumption of responsibility.
- Multiple mechanisms (a combination of those listed above).

Owners/operators of landfills in approved states or tribal jurisdictions may also use other state-approved mechanisms.

EPA is currently developing provisions for four additional financial mechanisms that owners/operators can use to satisfy the financial assurance requirements: (1) a financial test for local government owners/operators; (2) a financial test for corporate owners/operators; (3) a guarantee for local governments that wish to cover the costs of a municipal landfill for an owner/operator; and (4) a guarantee for corporations that wish to cover the costs of a landfill for an owner/operator.

Conclusion

The standards described in this booklet are federal minimum requirements for owners/operators of MSWLF units. Readers should understand that the regulation of municipal landfills is, and will continue to be, primarily a state and tribal function. States and tribes are therefore urged to revise their programs as soon as possible to incorporate these criteria, so that they can take advantage of the flexibility that accompanies program approval.

Owners/operators are again reminded that state and tribal programs may be more stringent than the federal criteria. They should work closely with state or tribal program officials and their regional EPA office to address questions about the requirements.

Areas of Flexibility for EPA-Approved States and Tribes

States and tribes with approved permitting programs have the opportunity to provide owners/operators additional flexibility. Some examples of this flexibility are listed below.

Approved states or tribes may:

Location:

- Allow siting of new and laterally expanding landfills in wetlands, providing certain conditions are met.
- Extend deadlines for closure of existing landfills that do not comply with the unstable area, floodplain, and airport safety provisions.

Operation:

- Allow use of alternative cover materials.
- Grant temporary waivers of cover requirement.

Design:

- Approve landfill designs appropriate for site-specific conditions.

Ground-water monitoring:

- Establish alternative schedules for existing landfills and lateral expansions of existing landfills to comply with ground-water monitoring.
- Establish a site-appropriate boundary (or relevant point of compliance) for ground-water monitoring (and corrective action and design).
- Allow use of a multi-unit ground-water monitoring system, instead of separate monitoring systems for each unit at a facility.
- Modify list of detection monitoring parameters (Appendix I constituents).
- Approve an alternative frequency for detection monitoring.
- Modify list of assessment monitoring parameters (Appendix II constituents).
- Specify alternative frequencies for assessment monitoring.
- Establish Ground-water Protection Standards for any constituent for which a Maximum Contaminant Level has not been established.

Corrective action:

- Determine that cleanup of a particular Appendix II constituent is not necessary.
- Specify an alternative time period defining the end of corrective action.

Closure and post-closure care:

- Approve use of an alternative final cover.
- Grant extensions beyond specified deadline for beginning closure activities.
- Grant extensions beyond specified deadline for completing closure.
- Reduce or increase the 30-year post-closure care period.

Financial assurance:

- Approve use of alternative financial assurance mechanisms.

For More Information

For more information about specific requirements for solid waste landfills in your area, contact your state solid waste agency. If you don't know how to reach them, call one of the resources listed below. The RCRA Hotline maintains current lists of all state solid and hazardous waste management officials. While these information centers are the best place to start collecting information, it may still be useful to ask these contacts if some other source may be able to give you additional help.

RCRA Hotline

Provides information about RCRA regulations and policies, and takes document requests.

Hours: Monday-Friday, 8:30 a.m. to 7:30 p.m., EST
Telephone: Toll-free — (800) 424-9346
TDD (hearing impaired) — (800) 553-7672
Washington metro area — (703) 412-9810
TDD — (703) 412-3323

EPA RCRA Information Center (Docket)

Maintains and tracks policy and guidance documents; provides nontechnical assistance and written reference services; develops and disseminates public information materials.

Hours: Monday-Friday, 9:00 a.m. to 4:00 p.m., EST
Telephone: (202) 260-9327
Address: RCRA Information Center
U.S. Environmental Protection Agency
401 M Street, SW. (OS-305)
Washington, DC 20460

Solid Waste Assistance Program

Collects and distributes information on all aspects of municipal solid waste management.

Hours: Monday-Friday, 8:30 a.m. to 5:00 p.m., EST
Telephone: Toll-free — (800) 677-9424
Address: Solid Waste Assistance Program
P.O. Box 7219
Silver Spring, MD 20910

National Response Center

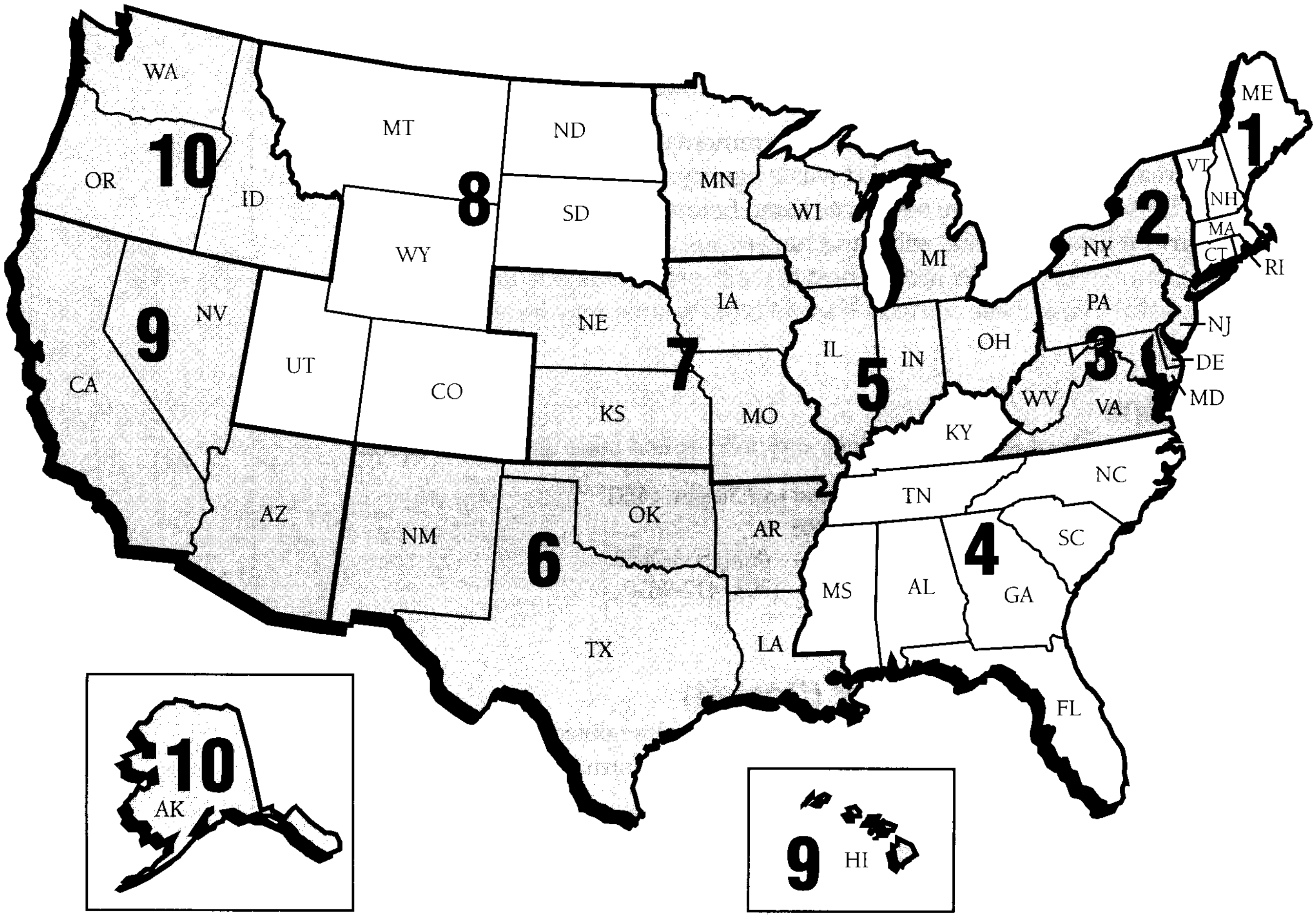
Accepts reports of oil and chemical spills or any other environmental incident.

Hours: 24 hours a day, 365 days a year.
Telephone: Toll-free — (800) 424-2675
Washington metro area — (202) 426-2675

EPA Small Business Ombudsman

Helps small businesses comply with environmental laws and EPA regulations.

Hours: Monday-Friday, 8:30 a.m. to 5:00 p.m., EST
Telephone: Toll-free — (800) 368-5888
Washington metro area — (703) 305-5938



EPA Regional Contacts

U.S. EPA Region 1
Waste Management
Division (HEE-CAN 6)
JFK Federal Building
Boston, MA 02203
(617) 573-9656

U.S. EPA Region 2
Air & Waste Management
Division (2AWM-SW)
26 Federal Plaza
New York, NY 10278
(212) 264-0002

U.S. EPA Region 3
RCRA Solid Waste
Program (3HW53)
841 Chestnut Street
Philadelphia, PA 19107
(215) 597-7936

U.S. EPA Region 4
Waste Management
Division
(4WD-RCRA-FF)
345 Courtland Street, NE
Atlanta, GA 30365
(404) 347-2091

U.S. EPA Region 5
Waste Management
Division (H-7J)
77 West Jackson Blvd.
Chicago, IL 60604
(312) 353-4686

U.S. EPA Region 6
RCRA Programs Branch
First Interstate Bank
Tower
1445 Ross Avenue,
Suite 1200
Dallas, TX 75202
(214) 655-6655

U.S. EPA Region 7
Waste Management
Division
726 Minnesota Avenue
Kansas City, KS 66101
(913) 551-7666

U.S. EPA Region 8
Hazardous Waste
Management Branch
(HWM-WM)
999 18th Street, Suite 500
Denver, CO 80202-2466
(303) 293-1661

EPA Region 9
Hazardous Waste
Management
Division (H-3-1)
75 Hawthorne Street
San Francisco, CA 94105
(415) 744-2074

U.S. EPA Region 10
Hazardous Waste Division
(HW-114)
1200 Sixth Avenue
Seattle, WA 98101
(206) 553-2857

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ATTACHMENT 2

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 423

[EPA–HQ–OW–2009–0819; FRL–9930–48–OW]

RIN 2040–AF14

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

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This final rule, promulgated under the Clean Water Act (CWA), protects public health and the environment from toxic metals and other harmful pollutants, including nutrients, by strengthening the technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating industry. Steam electric power plants contribute the greatest amount of all toxic pollutants discharged to surface waters by industrial categories regulated under the CWA. The pollutants discharged by this industry can cause severe health and environmental problems in the form of cancer and non-cancer risks in humans, lowered IQ among children, and deformities and reproductive harm in fish and wildlife. Many of these pollutants, once in the environment, remain there for years. Due to their close proximity to these discharges and relatively high consumption of fish, some minority and low-income communities have greater exposure to, and are therefore at greater risk from, pollutants in steam electric power plant discharges. The final rule establishes the first nationally applicable limits on the amount of toxic metals and other harmful pollutants that steam electric power plants are allowed to discharge in several of their largest sources of wastewater. On an annual basis, the rule reduces the amount of toxic metals, nutrients, and other pollutants that steam electric power plants are allowed to discharge by 1.4 billion pounds; it reduces water withdrawal by 57 billion gallons; and, it has social costs of $480 million and monetized benefits of $451 to $566 million.

DATES: The final rule is effective on January 4, 2016. In accordance with 40 CFR part 23, this regulation shall be considered issued for purposes of judicial review at 1 p.m. Eastern time on November 17, 2015. Under section 509(b)(1) of the CWA, judicial review of this regulation can be had only by filing a petition for review in the U.S. Court of Appeals within 120 days after the regulation is considered issued for purposes of judicial review. Under section 509(b)(2), the requirements in this regulation may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: *Docket:* All documents in the docket are listed in the *http://www.regulations.gov* index. A detailed record index, organized by subject, is available on EPA's Web site at *http://www2.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule.* Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Water Docket in the EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is 202–566–1744, and the telephone number for the Water Docket is 202–566–2426.

FOR FURTHER INFORMATION CONTACT: For technical information, contact Ronald Jordan, Engineering and Analysis Division, Telephone: 202–566–1003; Email: *jordan.ronald@epa.gov.* For economic information, contact James Covington, Engineering and Analysis Division, Telephone: 202–566–1034; Email: *covington.james@epa.gov.*

SUPPLEMENTARY INFORMATION:

Organization of This Preamble

Table of Contents

I. Regulated Entities and Supporting Documentation

A. Regulated Entities

Entities potentially regulated by this action include:

Category	Example of regulated entity	North American Industry Classification System (NAICS) Code
Industry	Electric Power Generation Facilities—Electric Power Generation	22111
	Electric Power Generation Facilities—Fossil Fuel Electric Power Generation	221112
	Electric Power Generation Facilities—Nuclear Electric Power Generation	221113

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

B. Supporting Documentation

This rule is supported, in part, by the following documents:

• Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD), Document No. EPA–821–R–15–007.

• Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EA), Document No. EPA–821–R–15–006.

• Benefits and Cost Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA), Document No. EPA–821–R–15–005.

• Regulatory Impact Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA), Document No. EPA–821–R–15–004.

These documents are available in the public record for this rule and on EPA's Web site at *http://www2.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule.*

II. Legal Authority for This Action

EPA promulgates this rule under the authority of sections 301, 304, 306, 307, 308, 402, and 501 of the CWA, 33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342, and 1361.

III. Executive Summary

A. Purpose of the Rule

Steam electric power plants [1] discharge large wastewater volumes, containing vast quantities of pollutants, into waters of the United States. The pollutants include both toxic and bioaccumulative pollutants such as arsenic, mercury, selenium, chromium, and cadmium. Today, these discharges account for about 30 percent of all toxic pollutants discharged into surface

[1] The steam electric power plants covered by the ELGs use nuclear or fossil fuels, such as coal, oil, or natural gas, to heat water in boilers, which generate steam. This rule does not apply to plants that use non-fossil fuel or non-nuclear fuel or other energy sources, such as biomass or solar thermal energy. The steam is used to drive turbines connected to electric generators. The plants generate wastewater composed of chemical pollutants and thermal pollution (heated water) from their wastewater treatment, power cycle, ash handling and air pollution control systems, as well as from coal piles, yard and floor drainage, and other plant processes.

waters by all industrial categories regulated under the CWA.[2] The electric power industry has made great strides to reduce air pollutant emissions under Clean Air Act programs. Yet many of these pollutants are transferred to the wastewater as plants employ technologies to reduce air pollution. The pollutants in steam electric power plant wastewater discharges present a serious public health concern and cause severe ecological damage, as demonstrated by numerous documented impacts, scientific modeling, and other studies. When toxic metals such as mercury, arsenic, lead, and selenium accumulate in fish or contaminate drinking water, they can cause adverse effects in people who consume the fish or water. These effects can include cancer, cardiovascular disease, neurological disorders, kidney and liver damage, and lowered IQs in children.

There are, however, affordable technologies that are widely available, and already in place at some plants, which are capable of reducing or eliminating steam electric power plant discharges. In the several decades since the steam electric ELGs were last revised, such technologies have increasingly been used at plants. This final rule is the first to ensure that plants in the steam electric industry employ technologies designed to reduce discharges of toxic metals and other harmful pollutants discharged in the plants' largest sources of wastewater.

Steam electric power plant discharges occur in proximity to nearly 100 public drinking water intakes and more than 1,500 public wells across the nation, and recent studies indicate that steam electric power plant discharges can adversely affect surface waters used as drinking water supplies. One study found that arsenic in ash and flue gas desulfurization (FGD) wastewater discharges from four steam electric power plants exceeded Safe Drinking Water Act (SDWA) Maximum Contaminant Levels (MCLS) in the waterbodies into which they discharged, indicating that these contaminants are present in surface waters, and at levels above standards used to protect drinking water. See DCN SE01984. A second, more recent study found increased levels of bromide in rivers used as drinking water after FGD systems were installed at upstream steam electric power plants. The study showed an increase in bromides at four drinking water utilities' intakes after wastewater from these FGD systems began to be discharged to the rivers, whereas prior to the FGD wastewater discharges, bromides were not a problem in the intake waters of the utilities. With bromides present in their drinking water source waters at increased levels, carcinogenic disinfection by-products (brominated DBPs, in particular trihalomethanes (THMs)) began forming, and at one drinking water utility, violations of the THM MCL began occurring. See DCN SE04503.

Nitrogen discharged by steam electric power plants can also impact drinking water sources by contributing to harmful algal blooms in reservoirs and lakes that are used as drinking water sources. Ground water contamination from surface impoundments (ash ponds) containing steam electric power plant wastewater also threatens drinking water, as evidenced by more than 30 documented cases. See EA Section 3.3.

Steam electric power plant discharges also adversely affect the quality of fish that people eat. Water quality modeling shows that about half of waterbodies that receive steam electric power plant discharges exhibit health risks to people consuming fish from those waters (primarily from mercury). Nearly half of waterbodies that receive steam electric power plant discharges exhibit pollutant levels for one or more steam electric power plant pollutants in excess of human health water quality criteria (WQC).[3] See EA Section 4. People who eat large amounts of fish from lakes and rivers contaminated by mercury, lead, and arsenic are particularly at risk, and consumption of such fish poses additional risk to the fetuses of pregnant women. Compared to the general public, minority and low-income communities have greater exposure to, and are therefore at greater risk from, pollutants in steam electric power plant discharges, due to their closer proximity to the discharges and greater consumption of fish from contaminated waters. See Section XVII.J.

Steam electric power plant discharges adversely affect our nation's waters and their ecology. Pollutants in such discharges, particularly mercury and selenium, bioaccumulate in fish and wildlife, and they accumulate in the sediments of lakes and reservoirs, remaining there for decades. Documented adverse impacts include the near eradication of an entire fish population in the late 1970s in Belews Lake, North Carolina, due to selenium discharges from a steam electric power plant (DCN SE01842); a series of fish kills in the 1970s in Martin Lake, Texas, also due to selenium discharges from a steam electric power plant (elevated selenium levels and deformities persisted for at least eight years after the plant ceased discharging) (DCN SE01861); reproductive impairment and deformities in fish and birds from selenium discharges (DCN SE04519); and other forms of impacts to surface waters, as documented by numerous other damage cases associated with discharges from surface impoundments containing steam electric power plant wastewater. See EA Section 3.3.

Waterbodies receiving steam electric power plant discharges have routinely exhibited pollutant levels routinely in excess of state WQC for pollutants found in the plant discharges. This includes pollutants such as selenium, arsenic, and cadmium. Nutrients in steam electric power plant discharges can cause over-enrichment of receiving waters, resulting in water quality problems, such as low oxygen levels and loss of critical submerged aquatic vegetation, further impairing beneficial uses such as fishing. EPA's modeling corroborates such documented impacts, revealing that nearly one fifth of waterbodies receiving steam electric power plant discharges exceed WQC for protection of aquatic life and nearly one third of such receiving waters pose potential reproductive risks to birds that prey on fish.

The steam electric ELGs that EPA promulgated and revised in 1974, 1977, and 1982 are out of date. They do not adequately control the pollutants (toxic metals and other) discharged by this industry, nor do they reflect relevant process and technology advances that have occurred in the last 30-plus years. The rise of new processes for generating electric power (*e.g.* coal gasification) and the widespread implementation of air pollution controls (*e.g.,* FGD and flue gas mercury control (FGMC)) have altered existing wastestreams and created new types of wastewater at many steam electric power plants, particularly coal-fired plants. The processes employed and pollutants discharged by the industry look very different today than they did in 1982. Many plants, nonetheless, still treat their wastewater using only surface impoundments, which are largely ineffective at controlling discharges of toxic pollutants and nutrients. This final rule addresses an outstanding public health and environmental problem by

[2] Although the way electricity is generated in this country is changing, EPA projects that, without this final rule, steam electric power plant discharges would likely continue to account, over the foreseeable future, for about thirty percent of all toxic pollutants discharged into surface waters by all industrial categories regulated under the CWA.

[3] WQCs are established by states to protect beneficial uses of waterbodies, such as the support of aquatic life and provision of fishing and swimming.

revising the steam electric ELGs, as they apply to a subset of power plants that discharge wastestreams containing toxic and other pollutants. As the CWA requires, this rule is economically achievable (affordable for the industry as a whole) and is based on available technologies. On an annual basis, the rule is projected to reduce the amount of toxic metals, nutrients, and other pollutants that steam electric power plants are allowed to discharge by 1.4 billion pounds; reduce water withdrawal by 57 billion gallons; and, it has estimated social costs of $480 million. Finally, of the benefits that were able to be monetized, EPA projects $451 to $566 million in benefits associated with this rule.

B. Summary of Final Rule

To further its ultimate objective to ''restore and maintain the chemical, physical, and biological integrity of the Nation's waters,'' the CWA authorizes EPA to establish national technology-based effluent limitations guidelines and new source performance standards for discharges from categories of point sources that occur directly into waters of the U.S. The CWA also authorizes EPA to promulgate nationally applicable pretreatment standards that control pollutant discharges from existing and new sources that discharge wastewater indirectly to waters of the U.S. through sewers flowing to publicly owned treatment works (POTWs). EPA establishes ELGs based on the performance of well-designed and well-operated control and treatment technologies.

EPA completed a study of the steam electric category in 2009 and proposed the ELG rule in June 2013. The public comment period extended for more than three months. This final rule reflects the statutory factors outlined in the CWA, as well as EPA's full consideration of the comments received and updated analytical results.

Existing Sources—Direct Discharges. For existing sources that discharge directly to surface water, with the exception of oil-fired generating units and small generating units (those with a nameplate capacity of 50 megawatts (MW) or less), the final rule establishes effluent limitations based on Best Available Technology Economically Achievable (BAT). BAT is based on technological availability, economic achievability, and other statutory factors and is intended to reflect the highest performance in the industry (see Section IV.B.3). The final rule establishes BAT limitations as follows: [4]

- For fly ash transport water, bottom ash transport water, and FGMC wastewater, there are two sets of BAT limitations. The first set of BAT limitations is a numeric effluent limitation on Total Suspended Solids (TSS) in the discharge of these wastewaters (these limitations are equal to the TSS limitations in the previously established Best Practicable Control Technology Currently Available (BPT) regulations). The second set of BAT limitations is a zero discharge limitation for all pollutants in these wastewaters.[5]
- For FGD wastewater, there are two sets of BAT limitations. The first set of limitations is a numeric effluent limitation on TSS in the discharge of FGD wastewater (these limitations are equal to the TSS limitations in the previously established BPT regulations). The second set of BAT limitations is numeric effluent limitations on mercury, arsenic, selenium, and nitrate/nitrite as N in the discharge of FGD wastewater.[6]
- For gasification wastewater, there are two sets of BAT limitations. The first set of limitations is a numeric effluent limitation on TSS in the discharge of gasification wastewater (this limitation is equal to the TSS limitation in the previously established BPT regulations). The second set of BAT limitations is numeric effluent limitations on mercury, arsenic, selenium, and total dissolved solids (TDS) in the discharge of gasification wastewater.
- A numeric effluent limitation on TSS in the discharge of combustion residual leachate from landfills and surface impoundments. This limitation is equal to the TSS limitation in the previously established BPT regulations.

For oil-fired generating units and small generating units (50 MW or smaller), the final rule establishes BAT limitations on TSS in the discharge of fly ash transport water, bottom ash transport water, FGMC wastewater, FGD wastewater, and gasification wastewater. These limitations are equal to the TSS limitations in the existing BPT regulations.

New Sources—Direct Discharges. The CWA mandates that new source performance standards (NSPS) reflect the greatest degree of effluent reduction that is achievable, including, where practicable, a standard permitting no discharge of pollutants (see Section IV.B.4). NSPS represent the most stringent controls attainable, taking into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements. For direct discharges to surface waters from new sources, including discharges from oil-fired generating units and small generating units, the final rule establishes NSPS as follows:

- A zero discharge standard for all pollutants in fly ash transport water, bottom ash transport water, and FGMC wastewater.
- Numeric standards on mercury, arsenic, selenium, and TDS in the discharge of FGD wastewater.
- Numeric standards on mercury and arsenic in the discharge of combustion residual leachate.

Existing Sources—Discharges to POTWs. Pretreatment Standards for Existing Sources (PSES) are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. PSES are analogous to BAT effluent limitations for direct dischargers and are generally based on the same factors (see Section IV.B.5). The final rule establishes PSES as follows: [7]

- A zero discharge standard for all pollutants in fly ash transport water, bottom ash transport water, and FGMC wastewater.[8]
- Numeric standards on mercury, arsenic, selenium, and nitrate/nitrite as N in the discharge of FGD wastewater.
- Numeric standards on mercury, arsenic, selenium and TDS in the discharge of gasification wastewater.

New Sources—Discharges to POTWs. Pretreatment standards for new sources (PSNS) are also designed to prevent the discharge of any pollutant into a POTW that interferes with, passes through, or is otherwise incompatible with the POTW. PSNS are analogous to NSPS for direct dischargers, and EPA generally considers the same factors for both sets of standards (see Section IV.B.6). The final rule establishes PSNS that are the same as the rule's NSPS.

[4] For details on when the following BAT limitations apply, see Section VIII.C.

[5] When fly ash transport water or bottom ash transport water is used in the FGD scrubber, the applicable limitations are those established for FGD wastewater on mercury, arsenic, selenium and nitrate/nitrite as N.

[6] For plants that opt into the voluntary incentives program, the second set of BAT limitations is numeric effluent limitations on mercury, arsenic, selenium, and TDS in the discharge of FGD wastewater.

[7] For details on when PSES apply, see Section VIII.E.

[8] When fly ash transport water or bottom ash transport water is used in the FGD scrubber, the applicable standards are those established for FGD wastewater on mercury, arsenic, selenium and nitrate/nitrite as N.

C. Summary of Costs and Benefits

Table III–1 summarizes the benefits and social costs for the final rule, at three percent and seven percent discount rates. EPA's analysis reflects the Agency's understanding of the actions steam electric power plants will take to meet the limitations and standards in the final rule. EPA based its analysis on a baseline that reflects the expected impacts of other environmental regulations affecting steam electric power plants, such as the Clean Power Plan (CPP) rule that the Agency finalized in July 2015 (as well as other relevant rules such as the Coal Combustion Residuals (CCR) rule that the Agency promulgated in April 2015). EPA understands that these modeled results have uncertainty due to the possibility of unexpected implementation approaches and thus that the actual costs could be somewhat higher or lower than estimated. The current estimate reflects the best data and analysis available at this time. In this preamble, EPA presents costs and monetized benefits accounting for these other rules.[9] Under this final rule, EPA estimates that about 12 percent of steam electric power plants and 28 percent of coal-fired or petroleum coke-fired power plants will incur some costs.[10] For additional information, see Sections V and IX.

TABLE III–1—TOTAL MONETIZED ANNUALIZED BENEFITS AND COSTS OF THE FINAL RULE

[Millions; 2013$]

Discount rate	Total monetized social benefits		Total social costs	
	3%	7%	3%	7%
Final Rule	$451 to $566	$387 to $478	$480	$471

The remainder of this preamble is structured as follows. Section IV provides additional background on the CWA and the ELG program. Section V outlines key updates since the proposal, including updates to the industry profile, estimated costs and economic impacts, and pollutant data. Section VI gives an overview of the industry, and Section VII reviews the identification and selection of the regulated pollutants. Section VIII describes the final rule requirements, along with the bases for EPA's decisions. Section IX presents the costs and economic impacts, while Section X shows the accompanying pollutant reductions. Section XI presents the numeric limitations and standards for existing and new sources that are established in this final rule. Sections XII through XIV explain the non-water quality environmental impacts (including energy requirements), the environmental assessment, and the resulting benefits analysis. Section XV presents results of the cost-effectiveness analysis, and Section XVI provides information regarding implementation of the rule.

IV. Background

A. Clean Water Act

Congress passed the CWA to ''restore and maintain the chemical, physical, and biological integrity of the Nation's waters.'' 33 U.S.C. 1251(a). In order to achieve this objective, the Act has, as a national goal, the elimination of the discharge of all pollutants into the nation's waters. 33 U.S.C. 1251(a)(1). The CWA establishes a comprehensive program for protecting our nation's waters. Among its core provisions, the CWA prohibits the discharge of pollutants from a point source to waters of the U.S., except as authorized under the CWA. Under section 402 of the CWA, 33 U.S.C. 1342, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA establishes a dual approach for these permits, technology-based controls that establish a floor of performance for all dischargers, and water quality-based effluent limitations, where the technology-based effluent limitations are insufficient to meet applicable WQS. To serve as the basis for the technology-based controls, the CWA authorizes EPA to establish national technology-based effluent limitations guidelines and new source performance standards for discharges from categories of point sources (such as industrial, commercial, and public sources) that occur directly into waters of the U.S.

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

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

EPA promulgates national ELGs for major industrial categories for three classes of pollutants: (1) Conventional pollutants (TSS, oil and grease, biochemical oxygen demand (BOD_5), fecal coliform, and pH), as outlined in

[10] EPA estimates that the population of steam electric power plants is about 1080.

CWA section 304(a)(4) and 40 CFR 401.16; (2) toxic pollutants (*e.g.,* toxic metals such as arsenic, mercury, selenium, and chromium; toxic organic pollutants such as benzene, benzo-a-pyrene, phenol, and naphthalene), as outlined in CWA section 307(a), 33 U.S.C. 1317(a); 40 CFR 401.15 and 40 CFR part 423, appendix A; and (3) nonconventional pollutants, which are those pollutants that are not categorized as conventional or toxic (*e.g.,* ammonia-N, phosphorus, and TDS).

B. Effluent Guidelines Program

EPA establishes ELGs based on the performance of well-designed and well-operated control and treatment technologies. The legislative history of CWA section 304(b), which is the heart of the effluent guidelines program, describes the need to press toward higher levels of control through research and development of new processes, modifications, replacement of obsolete plants and processes, and other improvements in technology, taking into account the cost of controls. Congress has also stated that EPA need not consider water quality impacts on individual water bodies as the guidelines are developed; see Statement of Senator Muskie (principal author) (October 4, 1972), reprinted in Legislative History of the Water Pollution Control Act Amendments of 1972, at 170. (U.S. Senate, Committee on Public Works, Serial No. 93–1, January 1973).

There are four types of standards applicable to direct dischargers, and two types of standards applicable to indirect dischargers, described in detail below.

1. Best Practicable Control Technology Currently Available

Traditionally, EPA establishes effluent limitations based on BPT by reference to the average of the best performances of facilities within the industry, grouped to reflect various ages, sizes, processes, or other common characteristics. EPA can promulgate BPT effluent limitations for conventional, toxic, and nonconventional pollutants. In specifying BPT, EPA looks at a number of factors. EPA first considers the cost of achieving effluent reductions in relation to the effluent reduction benefits. The Agency also considers the age of equipment and facilities, the processes employed, engineering aspects of the control technologies, any required process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. See CWA section 304(b)(1)(B), 33 U.S.C. 1314(b)(1)(B). If, however, existing performance is uniformly inadequate, EPA may establish limitations based on higher levels of control than what is currently in place in an industrial category, when based on an Agency determination that the technology is available in another category or subcategory and can be practically applied.

2. Best Conventional Pollutant Control Technology

The 1977 amendments to the CWA require EPA to identify additional levels of effluent reduction for conventional pollutants associated with Best Conventional Pollutant Control Technology (BCT) for discharges from existing industrial point sources. In addition to other factors specified in section 304(b)(4)(B), 33 U.S.C. 1314(b)(4)(B), the CWA requires that EPA establish BCT limitations after consideration of a two-part ‘‘cost reasonableness’’ test. EPA explained its methodology for the development of BCT limitations on July 9, 1986 (51 FR 24974). Section 304(a)(4) designates the following as conventional pollutants: BOD_5, TSS, fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as a conventional pollutant on July 30, 1979 (44 FR 44501; 40 CFR 401.16).

3. Best Available Technology Economically Achievable

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

4. Best Available Demonstrated Control Technology/New Source Performance Standards

NSPS reflect ‘‘the greatest degree of effluent reduction’’ that is achievable based on the ‘‘best available demonstrated control technology’’ (BADCT), ‘‘including, where practicable, a standard permitting no discharge of pollutants.’’ CWA section 306(a)(1), 33 U.S.C. 1316(a)(1). Owners of new facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS generally represent the most stringent controls attainable through the application of BADCT for all pollutants (that is, conventional, nonconventional, and toxic pollutants). In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements. CWA section 306(b)(1)(B), 33 U.S.C. 1316(b)(1)(B).

5. Pretreatment Standards for Existing Sources

Section 307(b) of the CWA, 33 U.S.C. 1317(b), authorizes EPA to promulgate pretreatment standards for discharges of pollutants to POTWs. PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT. Congress intended for the combination of pretreatment and treatment by the POTW to achieve the level of treatment that would be required if the industrial source were making a direct discharge. Conf. Rep. No. 95–830, at 87 (1977), reprinted in U.S. Congress. Senate Committee on Public Works (1978), A

Legislative History of the CWA of 1977, Serial No. 95–14 at 271 (1978). The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR part 403. These regulations establish pretreatment standards that apply to all non-domestic dischargers. *See* 52 FR 1586 (January 14, 1987).

6. Pretreatment Standards for New Sources

Section 307(c) of the CWA, 33 U.S.C. 1317(c), authorizes EPA to promulgate PSNS at the same time it promulgates NSPS. As is the case for PSES, PSNS are designed to prevent the discharge of any pollutant into a POTW that interferes with, passes through, or is otherwise incompatible with the POTW. In selecting the PSNS technology basis, the Agency generally considers the same factors it considers in establishing NSPS, along with the results of a pass-through analysis. Like new sources of direct discharges, new sources of indirect discharges have the opportunity to incorporate into their operations the best available demonstrated technologies. As a result, EPA typically promulgates pretreatment standards for new sources based on best available demonstrated control technology for new sources. *See Nat'l Ass'n of Metal Finishers* v. *EPA,* 719 F.2d 624, 634 (3rd Cir. 1983).

C. Steam Electric Effluent Guidelines Rulemaking History

EPA provided a detailed history of the steam electric ELGs in the preamble for the proposed rule, including an explanation of why EPA initiated a steam electric ELG rulemaking following a detailed study in 2009. EPA published the proposed rule on June 7, 2013, and took public comments until September 20, 2013. 78 FR 34432. During the public comment period, EPA received over 200,000 comments. EPA also held a public hearing on July 9, 2013.

V. Key Updates Since Proposal

This section discusses key updates since EPA proposed its rule in June 2013, including how these updates are reflected in the final rule.

A. Industry Profile Changes Due to Retirements and Conversions

For the final rule, EPA adjusted the population of steam electric power plants that will likely incur costs and the associated benefits as a result of this final rule based on company announcements, as of August 2014, regarding changes in plant operations. The steam electric industry is a dynamic one, influenced by many factors, including electricity demand, fuel prices, availability of resources, and regulation. Since proposal, there have been some important changes in the overall industry profile. Some companies have retired or announced plans to retire specific steam electric generating units, as well as converted or announced plans to convert specific units to a different fuel source. See DCN SE05069 for information on the data sources for these announced retirements and conversions. In addition to actual or announced retirements and fuel conversions, in some cases, plants have altered, or announced plans to alter, their wastewater treatment or ash handling practices. To the extent possible, EPA adjusted its analyses of costs, pollutant loadings, non-water quality environmental impacts, and benefits for the final rule to account for these actual and anticipated changes. The final rule accounts for plant retirements and fuel conversions, as well as changes in plants' ash handling and wastewater treatment practices, expected to occur by the implementation dates in the final rule. For more details, see TDD Section 4.5 or ''Changes to Industry Profile for Steam Electric Generating Units for the Steam Electric Effluent Guidelines Final Rule,'' DCN SE05059.

B. EPA Consideration of Other Federal Rules

EPA made every effort to appropriately account for other rules in its many analyses for this rule. Since proposal, EPA has promulgated other rules affecting the steam electric industry: the Cooling Water Intake Structures (CWIS) rule for existing facilities (79 FR 48300; Aug. 15, 2014), the CCR rule (80 FR 21302; Apr. 17, 2015), the CPP rule (see *http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants*), and the Carbon Pollution Standard for New Power Plants (CPS) rule (see *http://www2.epa.gov/cleanpowerplan/carbon-pollution-standards-new-modified-and-reconstructed-power-plants*). One result of taking into account these rules is a change in the population of units and plants that EPA estimates would incur incremental costs, as well as additional estimated benefits, under this final rule. In some cases, EPA performed two sets of parallel analyses to demonstrate how the other rules affected this final rule. For example, EPA conducted an assessment of compliance costs and pollutant loadings for this rule both with and without accounting for the CCR rule (this preamble only presents results accounting for the CCR rule). Then, using results from the analyses of costs and loadings accounting for the CCR rule, EPA also conducted an additional set of analyses of compliance costs and pollutant loadings accounting for the proposed CPP rule (this preamble only presents results accounting for the proposed CPP rule). At the time EPA conducted its analyses, the CPP had not yet been finalized, and thus EPA used the proposed CPP for its analyses. EPA concluded that the proposed and final CPP specifications are similar enough that using the proposed rather than the final CPP will not bias the results of the analysis for this rule. See Section IX for additional information. Because EPA used the proposal as a proxy for the final rule, the rest of the preamble simply refers to the CPP rule. Given that final CPP state plans have not yet been determined, EPA recognizes that the modeled results have uncertainty due to the possibility of unexpected implementation approaches and that actual market responses may be somewhat more or less pronounced than estimated. The current estimate reflects the best data and analysis available at this time. For more information on these federal rules, see TDD Section 1.3.3. For more information on how EPA accounted for the effect of these rules on its compliance cost, pollutant loadings estimates, and non-water quality environmental impacts, see TDD Sections 9, 10, and 12. See Section V.D. and Section IX, below, and the RIA regarding how EPA considered other federal rules in its economic impact analysis.

C. Advancements in Technologies

There have been advancements in several technologies since proposal that reinforce EPA's decision regarding those technologies that serve as the appropriate basis for the final rule. For proposal, EPA evaluated a variety of technologies available to control and treat wastewater generated by the steam electric industry. The final rule is based on several treatment technologies discussed in depth at proposal. As explained then, and further discussed in Section VIII, the record demonstrates that the technologies that form the basis for the final rule are available. Moreover, the record indicates that, based on the emerging market for treatment technologies, plants will have many options to choose from when deciding how to meet the requirements of the final rule.

The biological treatment technology that serves as part of the basis for the final requirements for FGD wastewater discharged from existing sources has been tested at power plants for more than ten years and demonstrated in full-scale systems for more than seven years. As this technology has matured, new vendors have emerged to provide expertise in applying it to steam electric power plants. In addition, other advanced technologies that plants may use to achieve the effluent limitations and standards for FGD wastewater in the final rule are now entering the marketplace, such as lower-cost biological treatment systems that utilize a modular-based bioreactor, which is prefabricated and can be delivered directly to the site. Another advancement related to evaporation and crystallization technology, operating at low temperatures to crystallize dissolved solids, requires no chemical treatment of the wastewater and generates no additional sludge for disposal, resulting in a simpler and more economical application for treatment of both FGD wastewater and gasification wastewater. Another development concerning the evaporation system (which is the basis for the BAT limitations for FGD wastewater in the voluntary incentives program, as well as the basis for the NSPS for FGD wastewater) is a process that generates a pozzolanic material instead of crystallized salts as a solid waste product of the treatment system; although the pozzolanic material is expected to require landfill disposal since it likely would not be a marketable material, the capital and operating cost of the overall evaporation treatment process would be reduced.

Zero valent iron (ZVI) cementation, sorption media, ion exchange, and electrocoagulation are also examples of emerging treatment technologies that are being developed to treat FGD wastewater, and they could be used to achieve the limitations in the final rule. See TDD Section 7 for a more detailed discussion.

The technologies used as the basis for the final requirements for ash transport water (dry handling and closed-loop systems) have been in operation at power plants for more than 20 years and are amply demonstrated by the record supporting the final rule. Recent advancements related to bottom ash handling technologies have focused on providing more flexible retrofit solutions and improving the thermal efficiency of the boiler operation. These advancements result in additional savings related to electricity use, operation and maintenance, water costs, and thermal energy recovery.

In sum, the record demonstrates that there have been significant advancements in relevant treatment technologies since proposal, and EPA expects that the advancements will continue as this rule is implemented by the industry.

D. Engineering Costs

For the final rule, EPA updated its cost estimates to account for public comments. The following list summarizes the main adjustments EPA made to its cost estimates for the final rule:

- Adjustment of population of generating units and changes in wastewater treatment or ash handling practices to account for company-announced generating unit retirements/repowerings and conversions of ash handling systems (see Section IV.A);
- Adjustment of population of generating units and changes in wastewater treatment or ash handling practices to account for implementation of the CCR rule and CPP rule (see Section IV.B);
- Adjustments to the direct capital costs factors to better reflect all associated installation costs;
- Adjustments to the indirect capital cost factors to account for appropriate engineering and contingency costs;
- Adjustment to plant population receiving one-time bottom ash management costs;
- Addition of costs for denitrification pretreatment prior to biological treatment of FGD wastewater (for certain plants);
- Updates to costing inputs to account for costs of additional redundancy for the fly ash dry handling system;
- Addition of tank rental costs for surge capacity during certain bottom ash handling system maintenance;
- Addition of building costs for certain bottom ash and FGD wastewater systems; and
- Addition of costs for equipment that can be used to mitigate high oxidation-reduction potential (ORP) levels in FGD wastewater.

See Section 9 of the TDD for additional information on the plant-specific compliance cost estimates for the final rule.

E. Economic Impact Analysis

For its analysis of the economic impact of the final rule, EPA began with the same financial data sources for steam electric power plants and their parent companies that were used and described in the proposed rule, primarily collected through the *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (industry survey) [11] and public sources. Since proposal, EPA updated some of the analysis input data obtained from public sources to reflect the most current information about the economic/financial conditions in, and the regulatory environment of, the electric power industry, as well as data on electricity prices and electricity consumption. Thus, EPA updated its analysis to use the most current publicly available data from the following sources: The Department of Energy's Energy Information Administration (EIA) (in particular, the EIA 860, 861, and 906/920/923 databases),[12] the U.S. Small Business Administration (SBA), the Bureau of Labor Statistics (BLS), and the Bureau of Economic Analysis (BEA). As was the case for the proposed rule, EPA performed an analysis using the Integrated Planning Model (IPM), a comprehensive electricity market optimization model that can evaluate impacts within the context of regional and national electricity markets. For the final rule, EPA used an updated IPM base case (v5.13) that incorporates improvements and data updates to the previous version (v.4.10), notably regarding electricity demand forecast, generating capacity, market conditions, and newly promulgated environmental regulations also affecting this industry (see Section IX).

F. Pollutant Data

For the final rule, EPA incorporated data submitted by public commenters in its effluent limitations and standards development, pollutants of concern identification, and pollutant loadings estimates. Such data include:

- Industry-submitted data representing the FGD purge, FGD chemical precipitation effluent, and FGD biological treatment effluent for the plants identified as operating BAT systems;
- Industry-submitted ash transport water characterization and source water data; [13]

[11] For details on the industry survey, see TDD Section 3 and 78 FR 34432; June 7, 2013).

[12] EIA–860: Annual Electric Generator Report; EIA–861: Annual Electric Power Industry Database; EIA–923: Utility, Non-Utility, and Combined Heat & Power Plant Database (monthly). The most current EIA data at the time of the analysis was for the year 2012.

[13] Industry also submitted bottom ash transport water data approximately 14 months after the close of the public comment period. EPA did not incorporate these late data into its analyses, but it did perform a sensitivity analysis to determine how these late data might have impacted EPA's analyses and decisions. EPA concluded from the sensitivity analysis that the late bottom ash transport water data would not have changed EPA's ultimate decisions for this final rule. See DCN SE05581.

• Industry-submitted ash impoundment effluent concentrations; and

• Industry-submitted pilot-test data related to treatment of FGD wastewater.

EPA subjected the new data to its data quality acceptance criteria and, as appropriate, updated its analyses accordingly. See TDD Section 3 for additional information on the data sources used in the development of the final rule.

G. Environmental Assessment Models

Although not required to do so, EPA conducted an Environmental Assessment for the final rule, as it did for the proposed rule. EPA updated the environmental assessment in several ways to respond to public comments, and improve the characterization of the environmental and human health improvements associated with the final rule. EPA performed dynamic water quality modeling of selected case-study locations to supplement the results of the national-scale Immediate Receiving Water (IRW) model. EPA supplemented the wildlife analysis by developing and using an ecological risk model that predicts the risk of reproductive impacts among fish and birds with dietary exposure to selenium from steam electric power plant wastewater discharges. EPA also updated and improved several input parameters for the IRW model, including fish consumption rates for recreational and subsistence fishers, the bioconcentration factor for copper, and benchmarks for assessing the potential for impacts to benthic communities in receiving waters. See Section XIII.A for additional discussion.

VI. Industry Description

A. General Description of Industry

EPA provided a general description of the steam electric industry in the proposed rule and provides a complete discussion of the industry in TDD Section 4. As described in TDD Section 4.5 (and Section V.A, above), EPA considered retirements, fuel conversions, ash handling conversions, wastewater treatment updates, and other industry profile changes in the development of the final rule and supporting technical analyses; however, the data presented in the general industry description represents 2009 conditions, as the industry survey (See TDD Section 3) remains the best available source of information for characterizing operations across the industry.

B. Steam Electric Process Wastewater and Control Technologies

While almost all steam electric power plants generate certain wastewater, like cooling water and boiler blowdown, the presence of other wastestreams depends on the type of fuel burned. Coal- and petroleum coke-fired generating units, and to a lesser degree oil-fired generating units, generate a flue gas stream that contains large quantities of particulate matter, sulfur dioxide, and nitrogen oxides, which would be emitted to the atmosphere if they were not cleaned from the flue gas prior to emission. Therefore, many of these generating units are outfitted with air pollution control systems (*e.g.,* particulate removal systems, FGD systems, nitrogen oxide (NO_X)-removal systems, and mercury control systems). Gas-fired generating units generate fewer emissions of particulate matter, sulfur dioxide, and nitrogen oxides than coal- or oil-fired generating units, and therefore do not typically operate air pollution control systems to control emissions from their flue gas. In addition, coal-, oil-, and petroleum coke-fired generating units create fly and/or bottom ash as a result of coal combustion. The wastewaters associated with ash transport and air pollution control systems contain large quantities of metals (*e.g.,* arsenic, mercury, and selenium).

See TDD Sections 4, 6, and 7 for details on these systems, the wastewaters they generate, the number of facilities that operate the systems and generate wastewater, and the control technologies used for wastewater treatment prior to discharge.

1. FGD Wastewater

FGD systems are used to remove sulfur dioxide from the flue gas so that it is not emitted into the air. Dry FGD systems spray a sorbent slurry into a reactor vessel so that the droplets dry as they contact the hot flue gas. Although dry FGD scrubbers use water in their operation, the water in most systems evaporates and they generally do not discharge wastewater. Wet FGD systems contact the sorbent slurry with flue gas in a reactor vessel producing a wastewater stream.

Treatment technologies for FGD wastewater include chemical precipitation, biological treatment, and evaporation. At some plants, this wastewater is handled in surface impoundments, constructed wetlands, or through practices achieving zero discharge. As described above in Section V.C and TDD section 7, EPA identified other technologies that have been evaluated or are being developed to treat FGD wastewater, including iron cementation, ZVI cementation, reverse osmosis, absorption or adsorption media, ion exchange, and electrocoagulation.

2. Fly Ash Transport Water

Plants use particulate removal systems to collect fly ash and other particulates from the flue gas in hoppers located underneath the equipment. Of the coal-, petroleum coke-, and oil-fired steam electric power plants that generate fly ash, most of them transport fly ash pneumatically from the hoppers to temporary storage silos, thereby not generating any transport water. Some plants, however, use water to transport (sluice) the fly ash from the hoppers to a surface impoundment. The water used to transport the fly ash to the surface impoundment is usually discharged to surface water as overflow from the impoundment after the fly ash has settled to the bottom.

3. Bottom Ash Transport Water

Bottom ash consists of heavier ash particles that are not entrained in the flue gas and fall to the bottom of the furnace. In most furnaces, the hot bottom ash is quenched in a water-filled hopper. For purposes of this rule, boiler slag is considered bottom ash. Boiler slag is the molten bottom ash collected at the base of the furnace that is quenched with water. Most plants use water to transport (sluice) the bottom ash from the hopper to an impoundment or dewatering bins. The ash sent to a dewatering bin is separated from the transport water and then disposed. For both of these systems, the water used to transport the bottom ash to the impoundment or dewatering bins is usually discharged to surface water as overflow from the systems, after the bottom ash has settled to the bottom.

Of the coal-, petroleum coke-, and oil-fired steam electric power plants that generate bottom ash, most operate wet sluicing handling systems. There are two types of bottom ash handling technologies that can meet zero discharge requirements: (1) Dry handling technologies that do not use any water, including systems such as dry vacuum or pressure systems, dry mechanical conveyor systems, and vibratory belt systems; and (2) wet systems that do not generate or discharge ash transport water, including mechanical drag systems (MDS), remote MDS, and complete-recycle systems.

4. FGMC Wastewater

FGMC systems remove mercury from the flue gas, so that it is not emitted into the air. There are two types of systems used to control flue gas mercury emissions: (1) Addition of oxidizing agents to the coal prior to combustion; and (2) injection of activated carbon into the flue gas after combustion. Addition of oxidizing agents to the coal prior to combustion does not generate a new wastewater stream; it can, however, increase the mercury concentration in the FGD wastewater because the oxidized mercury is more easily removed by the FGD system. Injection of activated carbon into the flue gas does have the potential to generate a new wastestream at a plant, depending on the location of the injection. If the injection occurs upstream of the primary particulate removal system, then the mercury-containing carbon (FGMC waste) is collected and handled the same way as, and together with, the fly ash. Therefore, if the fly ash is wet sluiced, then the FGMC wastes are also wet sluiced and likely sent to the same surface impoundment. In this case, adding the FGMC waste to the fly ash can increase the amount of mercury in the fly ash transport water. If the injection occurs downstream of the primary particulate removal system, the plant will need a secondary particulate removal system (typically a fabric filter) to capture the FGMC wastes.

Of the current or planned activated carbon injection systems, most operate upstream injection. However, plants that wish to market their fly ash will typically inject the activated carbon downstream of the primary particulate removal system to prevent contaminating the fly ash with carbon. For plants operating downstream injection, the FGMC wastes, which would be collected with some carry-over fly ash, could be handled separately from fly ash in either a wet or dry handling system.

5. Combustion Residual Leachate From Landfills and Surface Impoundments

Combustion residuals comprise a variety of wastes from the combustion process, which are generally collected by or generated from air pollution control technologies. These combustion residuals can be stored at the plant in on-site landfills or surface impoundments. Leachate includes liquid, including any suspended or dissolved constituents in the liquid, that has percolated through or drained from waste or other materials placed in a landfill, or that passes through the containment structure (*e.g.,* bottom, dikes, berms) of a surface impoundment. Based on data from the industry survey, most landfills and some impoundments have a system to collect the leachate.

In a lined landfill or impoundment, the combustion residual leachate collected in the liner is typically transported to an impoundment (*e.g.,* collection pond). Some plants discharge the effluent from these impoundments containing combustion residual leachate directly to receiving waters, while other plants first send the impoundment effluent to another impoundment handling the ash transport water or other treatment system (*e.g.,* constructed wetlands) prior to discharge. Unlined impoundments and landfills usually do not collect leachate, which would allow the leachate to potentially migrate to nearby ground waters, drinking water wells, or surface waters.

Using data from the industry survey and site visits, surface impoundments are the most widely used systems to treat combustion residual leachate. EPA also identified different management practices, with approximately one-third of plants collecting the combustion residual leachate from impoundments and recycling it back to the impoundment from which it was collected. Some plants use their collected leachate as water for moisture conditioning of dry fly ash prior to disposal or for dust control around dry unloading areas and landfills.

6. Gasification Wastewater

Integrated Gasification Combined Cycle (IGCC) plants use a carbon-based feedstock (*e.g.,* coal or petroleum coke) and subject it to high temperature and pressure to produce a synthetic gas (syngas), which is used as the fuel for a combined cycle generating unit. After the syngas is produced, it undergoes cleaning prior to combustion. The wastewater generated by these cleaning processes, along with any condensate generated in flash tanks, slag handling water, or wastewater generated from the production of sulfuric acid, is referred to as ''grey water'' or ''sour water,'' and is generally treated prior to reuse or discharge.

EPA is aware of three plants that operate IGCC units in the U.S. All three plants currently treat their gasification wastewater with vapor-compression evaporation systems. One of these plants also includes a cyanide destruction stage as part of the treatment system.

VII. Selection of Regulated Pollutants

A. Identifying the Pollutants of Concern

In determining which pollutants warrant regulation in this rule, EPA first evaluated the wastewater characteristics to identify pollutants of concern (POCs). Constituents present in steam electric power plant wastewater are primarily derived from the parent carbon feedstock (*e.g.,* coal, petroleum coke). EPA characterized the wastewater generated by the industry and identified POCs (those pollutants commonly found) for each of the regulated wastestreams. For wastestreams where the final rule establishes numeric effluent limitations or standards, the POCs are those pollutants that have been quantified in a wastestream at sufficient frequency at treatable levels (concentrations). For wastestreams where EPA is establishing zero discharge limitations or standards, the POCs identified for each wastestream are those pollutants that are confirmed to be present at sufficient frequency in untreated wastewater samples of that wastestream. In both cases, in response to public comments, where EPA had available paired source water (intake water) data for a particular pollutant in an untreated process wastewater sample, EPA compared the two to confirm that the concentration in the untreated process wastewater sample exceeded that of the source water. See TDD Section 6.6 for details on EPA's analysis of POCs.

B. Selection of Pollutants for Regulation Under BAT/NSPS

For wastestreams where the final rule establishes numeric effluent limitations or standards, effluent limitations or standards for all POCs are not necessary to ensure that the pollutants are adequately controlled because many of the pollutants originate from similar sources, have similar treatability, and are removed by similar mechanisms. Because of this, it is sufficient to establish effluent limitations or standards for one or more indicator pollutants, which will ensure the removal of other POCs. For wastestreams where the final rule establishes zero discharge limitations or standards, all POCs are directly regulated.

For wastestreams where the final rule establishes numeric effluent limitations or standards, EPA selected a subset of pollutants as indicators for all regulated pollutants upon consideration of the following factors:

- EPA did not set limitations or standards for pollutants associated with treatment system additives because regulating these pollutants could interfere with efforts to optimize treatment system operation.
- EPA did not set limitations or standards for pollutants for which the treatment technology was ineffective

(*e.g.,* pollutant concentrations remained approximately unchanged or increased across the treatment system).

• EPA did not set limitations or standards for pollutants that are adequately controlled through the regulation of another indicator pollutant because they have similar properties and are treated by similar mechanisms as a regulated pollutant.

See TDD Section 11 for additional detail on EPA's analysis and rationale for selecting the regulated pollutants.

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

Before establishing PSES/PSNS for a pollutant, EPA examines whether the pollutant ''passes through'' a POTW to waters of the U.S. or interferes with the POTW operation or sludge disposal practices. In determining whether a pollutant passes through POTWs for these purposes, EPA generally compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment to the percentage removed by the BAT/NSPS technology basis. A pollutant is determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by the BAT/NSPS technology basis. Pretreatment standards are established for those pollutants regulated under BAT/NSPS that pass through POTWs.

Under this rule, for those wastestreams regulated with a zero discharge limitation or standard, EPA set the percentage removed by the technology basis at 100 percent. Because a POTW would not be able to achieve 100 percent removal of wastewater pollutants, it is appropriate to set PSES at zero discharge, otherwise pollutants would pass through the POTW.

For wastestreams for which the final rule establishes numeric limitations and standards, EPA determined the pollutant percentage removed by the rule's technology basis using the same data sources used to determine the long-term averages for each set of limitations and standards (see TDD Section 13). As it has done for other rulemakings, EPA determined the nationwide percentage removed by well-operated POTWs performing secondary treatment using one of two data sources:

• Fate of Priority Pollutants in Publicly Owned Treatment Works, September 1982, EPA 440/1–82/303 (50 POTW Study); or

• National Risk Management Research Laboratory Treatability Database, Version 5.0, February 2004 (formerly called the Risk Reduction Engineering Laboratory database).

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

Section VIII, below, summarizes the results of the pass-through analysis. EPA found that all of the pollutants considered for regulation under BAT/NSPS pass through and, therefore, also selected them for regulation under PSES/PSNS. For a more detailed discussion of how EPA performed its pass-through analysis, see TDD Section 11.

VIII. The Final Rule

A. BPT

The final rule does not revise the previously established BPT effluent limitations because the rule regulates the same wastestreams at the more stringent BAT/NSPS level of control. The rule does, however, make certain structural modifications to the BPT regulations in light of new and revised definitions. In particular, the final rule establishes separate definitions for FGD wastewater, FGMC wastewater, gasification wastewater, and combustion residual leachate, making clear that these four wastestreams are no longer considered low volume waste sources. Given these new and revised definitions, the final rule modifies the structure of the previously established BPT regulations so that they specifically identify these four wastestreams, but without changing their applicable BPT limitations, which are equal to those for low volume waste sources.

B. BAT/NSPS/PSES/PSNS Options

EPA analyzed many regulatory options at proposal, the details of which were discussed fully in the document published on June 7, 2013 (78 FR 34432). EPA proposed to regulate pollutants found in seven wastestreams found at steam electric power plants, each based on particular control technologies. Depending on the interests represented, public commenters supported virtually all of the regulatory options that EPA proposed—from the least stringent to the most stringent, and many options in between. For this final rule, based on public comments, EPA also considered a few additional regulatory options. None of these additional regulatory options involve regulation of different pollutants or wastestreams, or the application of different control technologies, than those explicitly considered and presented at proposal. Rather, they involve slight variations on the overall packaging of the key options presented at proposal. Thus, in developing this final rule, EPA named six main regulatory options, Options A, B, C, D, E, and F.[14] Table VIII–1 summarizes these six regulatory options. In general, as one moves from Option A to Option F, there is a greater estimated reduction in pollutant discharges from steam electric power plants and a higher associated cost.

The following paragraphs describe the six options (Options A through F), by wastestream, including the technology bases for the requirements associated with each.

TABLE VIII–1—FINAL RULE: STEAM ELECTRIC MAIN REGULATORY OPTIONS

Wastestreams	Technology basis for the main BAT/NSPS/PSES/PSNS regulatory options					
	A	B	C	D	E	F
FGD Wastewater	Chemical Precipitation	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Evaporation.
Fly Ash Transport Water	Dry handling	Dry handling	Dry handling	Dry handling	Dry handling	Dry handling.

[14] Option B is equivalent to Proposed Option 3, Option C is equivalent to Proposed Option 4a, Option E is equivalent to Proposed Option 4, and Option F is equivalent to Proposed Option 5. Option A is a slight variant of Proposed Options 1 and 3 and Option D is a slight variant of Proposed Option 4.

TABLE VIII–1—FINAL RULE: STEAM ELECTRIC MAIN REGULATORY OPTIONS—Continued

Wastestreams	Technology basis for the main BAT/NSPS/PSES/PSNS regulatory options					
	A	B	C	D	E	F
Bottom Ash Transport Water.	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Dry handling/ Closed loop (for units >400 MW); Impoundment (Equal to BPT)(for units ≤400 MW)	Dry handling/ Closed loop	Dry handling/ Closed loop	Dry handling/ Closed loop.
FGMC Wastewater	Dry handling	Dry handling	Dry handling	Dry handling	Dry handling	Dry handling.
Gasification Wastewater	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation.
Combustion Residual Leachate.	Impoundment (Equal to BPT).	Impoundment (Equal to BPT).	Impoundment (Equal to BPT).	Impoundment (Equal to BPT).	Chemical Precipitation.	Chemical Precipitation.
Nonchemical Metal Cleaning Wastes.	[Reserved]	[Reserved]	[Reserved]	[Reserved]	[Reserved]	[Reserved].

Consistent with the proposal, under all Options A through F, for oil-fired generating units and small generating units (50 MW or smaller) that are existing sources, the rule would establish BAT/PSES effluent limitations and standards on TSS in fly ash transport water, bottom ash transport water, FGD wastewater, FGMC wastewater, combustion residual leachate, and gasification wastewater equal to the previously promulgated BPT effluent limitations on TSS [15] in fly ash transport water, bottom ash transport water, and low volume waste sources, where applicable. Under Options A through E, EPA would establish a voluntary incentives program for plants that choose to meet BAT limitations for FGD wastewater based on evaporation technology, as described in Section VIII.C.13. Moreover, as EPA proposed, under all Options A through F, the rule would establish an anti-circumvention provision designed to ensure that the purpose of the rule is achieved, as further described below, in Section VIII.G. Finally, as EPA proposed, under all Options A through F, the rule would correct a typographical error in the previously promulgated regulations, as well as make certain clarifying revisions to the applicability provision of the regulations, as further described below, in Section VIII.H.

1. FGD Wastewater

Under Option A, EPA would establish effluent limitations and standards for mercury and arsenic in FGD wastewater based on treatment using chemical precipitation. Under Options B through E, EPA would establish effluent limitations and standards for mercury, arsenic, selenium, and nitrate/nitrite as N in FGD wastewater based on treatment using chemical precipitation (as under Option A) followed by biological treatment. Under Option F, EPA would establish effluent limitations and standards for mercury, arsenic, selenium, and TDS in FGD wastewater based on treatment using an evaporation system. Under all options, to facilitate implementation of the new BAT/NSPS/PSES/PSNS requirements, EPA would also promulgate a definition for FGD wastewater, making clear it would no longer be considered a low volume waste source.

2. Fly Ash Transport Water

Under all Options A through F, EPA would establish (or in the case of NSPS/PSNS, maintain) zero discharge effluent limitations and standards for pollutants in fly ash transport water based on use of a dry handling system.

3. Bottom Ash Transport Water

Under Options A and B, EPA would establish effluent limitations and standards for bottom ash transport water equal to the previously promulgated BPT limitation on TSS, which is based on the use of a surface impoundment. Under Options D, E, and F, EPA would establish zero discharge effluent limitations and standards for pollutants in bottom ash transport water based on one of two technologies: A dry handling system or a closed-loop system. Under Option C, EPA would establish, for bottom ash transport water, zero discharge limitations and standards based on dry handling or closed-loop systems only for generating units with a nameplate capacity of more than 400 MW. Units with a nameplate capacity equal to or less than 400 MW would have to meet new effluent limitations and standards equal to the previously established BPT limitation on TSS, based on surface impoundments.

4. FGMC Wastewater

Under all Options A through F, EPA would establish zero discharge effluent limitations and standards for FGMC wastewater based on use of a dry handling system. Under all Options A through F, EPA would establish a separate definition for FGMC wastewater, making clear it would no longer be considered a low volume waste source.

5. Gasification Wastewater

The technology basis for control of gasification wastewater under all Options A through F is an evaporation system. Under these options, EPA would establish limitations and standards on arsenic, mercury, selenium, and TDS in gasification wastewater. Under all Options A through F, EPA would establish a separate definition for gasification wastewater, making clear it would no longer be considered a low volume waste source.

6. Combustion Residual Leachate

Under Options A through D, EPA would establish effluent limitations and standards for combustion residual leachate equal to the previously promulgated BPT limitation on TSS for low volume waste sources. Under Options E and F, EPA would establish additional limitations and standards for arsenic and mercury in combustion residual leachate based on treatment using a chemical precipitation system (the same technology basis for control of FGD wastewater under Option A). Under all Options A through F, EPA would establish a separate definition for combustion residual leachate, making

[15] Although TSS is a conventional pollutant, whenever EPA would be regulating TSS in this final rule, it would be regulating it as an indicator pollutant for the particulate form of toxic metals.

clear it would no longer be considered a low volume waste source.

7. Non-Chemical Metal Cleaning Wastes

Under all Options A through F, EPA would continue to reserve BAT/NSPS/PSES/PSNS for non-chemical metal cleaning wastes, as the previously established regulations do.

C. Best Available Technology

After considering the technologies described in this preamble and Section 7 of the TDD, as well as public comments, and in light of the factors specified in CWA sections 304(b)(2)(B) and 301(b)(2)(A) (see Section IV.B.3), EPA decided to establish BAT effluent limitations based on the technologies described in Option D. Thus, for BAT, the final rule establishes: (1) Limitations on arsenic, mercury, selenium, and nitrate/nitrite as N in FGD wastewater, based on chemical precipitation plus biological treatment; [16] (2) a zero discharge limitation for pollutants in fly ash transport water, based on dry handling; (3) a zero discharge limitation for pollutants in bottom ash transport water, based on dry handling or closed-loop systems; (4) a zero discharge limitation on all pollutants in FGMC wastewater, based on dry handling; (5) limitations on mercury, arsenic, selenium, and TDS in gasification wastewater, based on evaporation; [17] and (6) a limitation on TSS in combustion residual leachate, based on surface impoundments.[18] The final rule also establishes new definitions for FGD wastewater, FGMC wastewater, gasification wastewater, and combustion residual leachate.

1. FGD Wastewater

This rule identifies treatment using chemical precipitation followed by biological treatment as the BAT technology basis for control of pollutants discharged in FGD wastewater. More specifically, the technology basis for BAT is a chemical precipitation system that employs hydroxide precipitation, sulfide precipitation (organosulfide), and iron coprecipitation, followed by an anoxic/anaerobic fixed-film biological treatment system designed to remove heavy metals, selenium, and nitrates.[19] After accounting for industry changes described in Section V, forty-five percent of all steam electric power plants with wet scrubbers have equipment or processes in place able to meet the final BAT/PSES effluent limitations and standards.[20] Many of these plants use FGD wastewater management approaches that eliminate the discharge of FGD wastewater.[21] Other plants employ wastewater treatment technologies that reduce the amount of pollutants in the FGD wastestream. Both chemical precipitation and biological treatment are well-demonstrated technologies that are available to steam electric power plants for use in treating FGD wastewater. Based on industry survey responses, 39 U.S. steam electric power plants (44 percent of plants discharging FGD wastewater) use some form of chemical precipitation as part of their FGD wastewater treatment system. More than half of these plants (30 percent of plants discharging FGD wastewater) use both hydroxide and sulfide precipitation in the process to further reduce metals concentrations. In addition, chemical precipitation has been used at thousands of industrial facilities nationwide for the last several decades (see TDD Section 7).

Biological treatment has been tested at power plants for more than ten years and full-scale systems have been operating at a subset of plants for seven years. It has been widely used in many industrial applications for decades, in both the U.S. and abroad, and it has been employed at coal mines. Currently, six U.S. steam electric power plants (approximately ten percent of those discharging FGD wastewater) use biological treatment designed to substantially reduce nitrogen compounds and selenium in their FGD wastewater. Other power plants are considering installing biological treatment to remove selenium, and at least one plant is scheduled to begin operating a biological treatment system for selenium removal soon. Four of the six plants using biological systems to treat their FGD wastewater precede the biological treatment stage with chemical precipitation; thus, the entire system is designed to remove suspended solids, particulate and dissolved metals (such as mercury and arsenic), soluble and insoluble forms of selenium, and nitrate and nitrite forms of nitrogen. These plants show that chemical precipitation followed by biological treatment is technologically available and demonstrated. The other two plants operating anoxic/anaerobic bioreactors to remove selenium precede the biological treatment stage with surface impoundments instead of chemical precipitation. The treatment systems at these two plants are likely to be less effective at removing metals (including many dissolved metals) and would likely face more operational problems than the plants employing chemical pretreatment, but they nevertheless show the efficacy and availability of biological treatment for removing selenium and nitrate/nitrite in FGD wastewater.

A few commenters questioned the feasibility of biological treatment at some power plants. Specifically, they claimed, in part, that the efficacy of biological systems is unpredictable and is subject to temperature changes, high chloride concentrations, scaling, and high oxidation-reduction potential (ORP) in the absorber, which could kill the microorganisms in the bioreactor. EPA's record does not support these assertions for a well-designed and well-operated chemical precipitation and biological treatment system.

EPA's record demonstrates that proper pretreatment prior to biological treatment and proper monitoring with adjustments to the treatment system as necessary are key to reducing operational concerns raised by commenters. Proper pretreatment includes chemical precipitation, which can address wastewater containing high oxidant loads through addition of a reducing agent in one of the treatment

[16] For those plants that choose to participate in the voluntary incentives program, the applicable limitations are for arsenic, mercury, selenium, and TDS in FGD wastewater, based on the use of an evaporation system (see Section VIII.C.13).

[17] For small (50 MW or less) generating units and oil-fired generating units, the final rule establishes different BAT limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater (see Section VIII.C.12).

[18] The final rule also establishes BAT limitations on TSS in discharges of "legacy wastewater," which are equal to previously established TSS limitations. See Section VIII.C.8.

[19] In estimating costs associated with this technology basis, EPA assumed that in order to meet the limitations and standards, certain plants with high FGD discharge flow rates (greater than or equal to 1,000 gpm) would elect to incorporate flow minimization into their operating practices (by reducing the FGD purge rate or recycling a portion of their FGD wastewater back to the FGD system), where the FGD system metallurgy can accommodate an increase in chlorides. See Section 4.5.4 of EPA's Incremental Costs and Pollutant Removals for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (DCNs SE05831 and SE05832).

[20] This value accounts for announced retirements, conversions, and changes plants are projected to make to comply with the CPP and CCR rules.

[21] A variety of approaches that depend on plant specific conditions are used to achieve zero pollutant discharge at these plants, including evaporation ponds, complete recycle, and processes that combine the FGD wastewater with other materials for landfill disposal. Although these technologies, as well as others currently used for achieve zero pollutant discharge, may be available for some plants with FGD wastewater, EPA determined they are not available nationally. For example, evaporation ponds are only available in certain climates. Similarly, complete recycle is only available at plants with appropriate FGD metallurgy.

system's reaction tanks.[22] It also includes pretreatment of FGD wastewater containing exceptionally high levels of nitrates (*e.g.,* greater than 100 ppm nitrate/nitrite as N) using standard denitrification technologies such as membrane bioreactors or stirred-tank bioreactors. Moreover, recent pilot studies of biological treatment systems for FGD wastewater treatment, along with data for full-scale biological treatment systems, demonstrate that monitoring ORP, pH, and total oxidant load is essential for proper operation of these systems. Monitoring these parameters enables the plant to adjust the system as necessary. For example, plants that monitor ORP in the absorber or in the FGD purge will have sufficient advanced warning to respond to elevated ORP levels by adding a chemical reductant to the chemical precipitation system and/or increasing the feed rate of the nutrient mix in the biological reactor. EPA's cost estimates account for all of these pretreatment and monitoring steps. EPA's record, moreover, shows that the treatment systems that form the bases for the BAT limitations for FGD wastewater are able to effectively remove the regulated pollutants at varying influent concentrations. See DCN SE05733. Finally, as discussed in Section V.C, vendors continue to make improvements to these systems and to develop non-biological systems for selenium removal. For additional information on strategies to address potential operational concerns, see DCNs SE04208 and SE04222.

Some commenters also claimed that the efficacy of biological systems in removing selenium is subject to changes in switching from one coal type to another (also referred to as fuel flexing). Where EPA had biological treatment performance data paired with fuel type, EPA reviewed it and found that existing biological treatment systems continue to perform well during periods of fuel switching. See DCN SE05846. The data show that, in all cases except one, the plants met the selenium limitations following fuel switches. In one instance when a plant switched to a certain coal type, the plant exceeded the final daily maximum selenium limitation for one out of thirteen observations for the month while the average of all values for that month were below the final monthly selenium limitation. This plant was not subject to a selenium limit at the time data was collected. Moreover, EPA's record demonstrates that effective communication between the operator(s) of the generating unit and the boiler, as well as bench testing and monitoring the ORP, and making proper adjustments to the operation of the treatment system, would make it possible to prevent potential selenium exceedances at this plant. Data for two other plants operating full-scale biological treatment systems shows that fuel switches should not result in exceeding the effluent limitations. EPA also has data from a pilot project at another plant employing the same type of coal used by the one plant that experienced elevated selenium effluent concentrations following a coal switch. The data for this pilot project demonstrate effective selenium removal by the BAT technology basis, with all effluent values at concentrations below the BAT limitations established in this rule.

EPA also reviewed effluent data in the record for plants operating combined chemical precipitation and biological treatment for FGD wastewater to evaluate how cycling operation (*i.e.,* changes in electricity generation rate) and short or extended shutdown periods may affect the ability of plants to meet the BAT effluent limitations. These data demonstrate that cycling operations and shutdown periods, whether short or long in duration, are manageable and do not result in plants being unable to meet the ELG effluent limitations. See DCN SE05846.

EPA did not select surface impoundments as the BAT technology basis for FGD wastewater because it would not result in reasonable further progress toward eliminating the discharge of all pollutants, particularly toxic pollutants (see CWA section 301(b)(2)(A)). Surface impoundments, which rely on gravity to remove particulates from wastewater, are the technology basis for the previously promulgated BPT effluent limitations for low volume waste sources. Pollutants that are present mostly in soluble (dissolved) form, such as selenium, boron, and magnesium, are not effectively and reliably removed by gravity in surface impoundments. For metals present in both soluble and particulate forms (such as mercury), gravity settling in surface impoundments does not effectively remove the dissolved fraction. Furthermore, the environment in some surface impoundments can create chemical conditions (*e.g.,* low pH) that convert particulate forms of metals to soluble forms, which are not removed by the gravity settling process. Additionally, the Electric Power Research Institute (EPRI) has reported that adding FGD wastewater to surface impoundments used to treat ash transport water can reduce the settling efficiency in the impoundments due to gypsum particle dissolution, thus increasing the effluent TSS concentrations. Discharging wastewater containing elevated levels of TSS would likely result in also discharging other pollutants (*e.g.,* metals) in higher concentrations. EPRI has also reported that FGD wastewater includes high loadings of volatile metals, which can increase the solubility of metals in surface impoundments, thereby leading to increased levels of dissolved metals and higher concentrations of metals in discharges from surface impoundments. Finally, as described in Section 8 of the TDD, surface impoundments are also subject to seasonal turnover, which adversely affects their efficacy. Seasonal turnover occurs when the impoundment's upper layer of water becomes cooler and denser, typically as the season changes from summer to fall. The cooler, upper layer of water then sinks and causes the entire volume of the impoundment to circulate, which can result in resuspension of solids that had settled to the bottom and a consequent increase in the concentrations of pollutants discharged from the impoundment.

Chemical precipitation and biological treatment are more effective than surface impoundments at removing both soluble and particulate forms of metals, as well as other pollutants such as nitrogen compounds and TDS. Because many of the pollutants of concern in FGD wastewater are present in dissolved form and would not be removed by surface impoundments, and because of the relatively large mass loads of these pollutants (*e.g.,* selenium, dissolved mercury) discharged in the FGD wastestream, EPA decided not to finalize BAT effluent limitations for FGD wastewater based on surface impoundments.

EPA also rejected identifying chemical precipitation, alone, (Option A) as BAT for FGD wastewater because, while chemical precipitation systems are capable of achieving removals of various metals, the technology is not effective at removing selenium, nitrogen compounds, and certain metals that contribute to high concentrations of TDS in FGD wastewater. These pollutants of concern are discharged by steam electric power plants throughout the nation, causing adverse human health impacts and some of the most egregious environmental impacts (see Section XIII and EA). In light of this, and the fact that economically achievable technologies are available to

[22] EPA included the equipment for chemical addition of a reducing agent in its cost estimates for Options B through E.

reduce these pollutants of concern, EPA determined that, by itself, chemical precipitation would not result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants (see CWA section 301(b)(2)(A)), and rejected that technology basis as BAT in favor of chemical precipitation followed by anaerobic/anoxic biological treatment.

EPA also decided not to establish, for all steam electric power plants, BAT limitations for FGD wastewater based on treatment using an evaporation system. In particular, this technology basis would employ a falling-film evaporator (also known as a brine concentrator) to produce a concentrated wastewater stream (brine) and a distillate stream.[23] While evaporation systems are effective at removing boron and pollutants that contribute to high concentrations of TDS, EPA decided it would not be appropriate to identify evaporation as the BAT technology basis for FGD wastewater at all steam electric power plants because of the high cost of possible regulatory requirements based on evaporation for discharges of FGD wastewater at existing facilities. The annual cost to the industry of limitations based on evaporation would be more than 2 and ½ times the cost to industry estimated for the final rule (after tax) (approximately $570 million more expensive than the final rule, on an annual basis, after tax). Given the high costs associated with the technology, and the fact that the steam electric industry is facing costs associated with several other rules in addition to this rule, EPA decided not to establish BAT limitations for FGD wastewater based on evaporation for all steam electric power plants. Nevertheless, as described further below, in Section VIII.C.13, the final rule does establish a voluntary incentives program under which steam electric power plants can choose to be subject to more stringent BAT limitations for FGD wastewater based on evaporation.

Finally, EPA decided not to establish a requirement that would direct permitting authorities to establish limitations for FGD wastewater using site-specific BPJ. Public commenters representing industry, state, and environmental group interests urged EPA not to establish any requirement that would leave BAT effluent limitations for FGD wastewater to be determined on a BPJ basis. Sections 301 and 304 of the CWA require EPA to develop nationally applicable ELGs based on the best available technology economically achievable, taking certain factors into account. EPA decided that it would not be appropriate to leave FGD wastewater requirements in the final rule to be determined on a BPJ basis because there are sufficient data to set uniform, nationally applicable limitations on FGD wastewater at plants across the nation. Given this, BPJ permitting of FGD wastewater would place an unnecessary burden on permitting authorities, including state and local agencies, to conduct a complex technical analysis that they may not have the resources or expertise to complete. BPJ permitting of FGD wastewater would also unnecessarily burden the regulated industry because of associated delays and uncertainty with respect to permits.

2. Fly Ash Transport Water

This rule identifies dry handling as the BAT technology basis for control of pollutants in fly ash transport water. Specifically, the technology basis for BAT is a dry vacuum system that employs a mechanical exhauster to pneumatically convey the fly ash (via a change in air pressure) from hoppers directly to a silo. Dry handling is clearly available to control the pollutants present in fly ash transport water. Today, the vast majority of steam electric power plants use dry handling techniques to manage fly ash, and by doing so avoid generating fly ash transport water. All new generating units built since the ELGs were last revised in 1982 have been subject to a zero discharge standard for pollutants in fly ash transport water. In addition, many owners and operators with generating units that are not subject to the previously established zero discharge NSPS for fly ash transport water have chosen to retrofit their units with dry fly ash handling technology to meet operational needs or for economic reasons. The trend in the industry is, moreover, toward the conversion and use of dry fly ash handling systems. See TDD Section 4.5. Based on data collected in the industry survey, EPA estimates that approximately 80 percent of coal and petroleum coke-fired generating units operate dry fly ash handling systems. Since the survey, companies have continued to upgrade, or announce plans to upgrade, their ash handling systems at generating units. See TDD Section 4.5.

Dry ash handling does not adversely affect plant operations or reliability, and it promotes the beneficial reuse of coal combustion residuals. In addition, converting to dry fly ash handling eliminates the need to treat fly ash transport water in a surface impoundment, and it reduces the amount of wastes entering surface impoundments and the risk and severity of structural failures and spills.

EPA decided not to finalize a BAT limitation on fly ash transport water equal to the previously promulgated BPT limitation on TSS, based on the technology of surface impoundments, for the same reasons (where applicable) that EPA did not identify surface impoundments as BAT for FGD wastewater (see Section VIII.C.1).

3. Bottom Ash Transport Water

This rule identifies dry handling or closed-loop systems as the BAT technology basis for control of pollutants in bottom ash transport water.[24] More specifically, the first technology basis for BAT is a system in which bottom ash is collected in a water quench bath and a drag chain conveyor (mechanical drag system) then pulls the bottom ash out of the water bath on an incline to dewater the bottom ash. The second technology basis for BAT is a system in which the bottom ash is transported using the same processes as a wet-sluicing system, but instead of going to an impoundment, the bottom ash is sluiced to a remote mechanical drag system. Once there, a drag chain conveyor pulls the bottom ash out of the water on an incline to dewater the bottom ash, and the transport (sluice) water is then recycled back to the bottom ash collection system.

These technologies for control of bottom ash transport water are demonstrably available. Based on survey data, more than 80 percent of coal-fired generating units built in the last 20 years have installed dry bottom ash handling systems. In addition, EPA found that more than half of the entities that would be subject to BAT requirements for bottom ash transport water are already employing zero discharge technologies (dry handling or closed-loop wet ash handling) or planning to do so in the near future.

Dry bottom ash handling does not adversely affect plant operations or reliability, and shifting to dry bottom ash handling offers certain benefits. As was the case for dry fly ash handling, shifting to dry bottom ash handling eliminates the need to send bottom ash transport water to a surface impoundment, and it reduces the

[23] This evaporation step would have been preceded by a chemical precipitation step using hydroxide precipitation, sulfide precipitation, and iron co-precipitation, as well as a softening step.

[24] EPA identified two technologies, a mechanical drag system or a remote mechanical drag system, as the BAT technology basis for bottom ash transport water because of potential space constraints at some plants' boilers.

amount of waste entering surface impoundments and the risk and severity of structural failures and spills. Furthermore, one way companies may choose to comply with the final rule's requirements is to install a completely dry bottom ash system, which increases the energy efficiency of the boiler, thus reducing the amount of coal burned and associated emissions of carbon dioxide (CO_2) and other pollutants per MW of electricity generated. On an annual basis, EPA calculated significant fuel savings and reduced air emissions from such systems, the value of which EPA estimates to be $41 million to $117 million per year.[25] See DCN SE05980.

EPA did not identify surface impoundments as BAT for bottom ash transport water for the same reasons (where applicable) that it did not identify surface impoundments as BAT for FGD wastewater (see Section VIII.C.1). Moreover, because the estimated overall cost of the rule has decreased since proposal (see Section IX), EPA also decided that establishing different bottom ash transport water limitations for generating units of and below a certain size (other than 50 MW, as described in Section VIII.C.12), as in Option C, was not warranted.

At proposal and for the final rule, EPA considered an option that would have established differentiated bottom ash transport water requirements for units below 400 MW (Option C). Some public commenters stated that EPA's record does not support differentiated requirements for bottom ash transport water. They stated that BAT should be established at a level at which the costs are affordable to the industry as a whole, and that the cost to a unit in terms of dollars per amount of energy produced (in MW) is not a relevant factor. They cited EPA's record, which demonstrates that units of all sizes have installed dry handling and closed-loop systems, as well as EPA's economic achievability analysis, which does not show that units of 400 MW or less are especially likely to shut down if faced with a zero discharge requirement. Other commenters supported EPA's consideration of the relative magnitude of costs per amount of energy produced for units below or equal to 400 MW, as compared to larger units, as well as differentiated bottom ash transport water requirements for these units.

EPA reviewed its record and re-evaluated whether it would be appropriate to establish differentiated requirements for discharges of bottom ash transport water from existing sources based on unit size, in light of comments and the key changes since proposal discussed in Section V. Annualized cost per amount of energy produced increases along a smooth curve moving from the very largest units to the smallest units. See DCN SE05813. That, however, is expected due to economies of scale. There is no clear breaking point at which to establish a size threshold for purposes of differentiated requirements for bottom ash transport water.[26] Furthermore, EPA collected information in the industry survey that found that units of all sizes, including those less than 400 MW, have installed dry handling and closed-loop systems. And, as further described below, EPA projects a net retirement of only 843 MW under the final rule. This suggests that, as a group, units of 400 MW or less do not face particularly unique hardships under the final rule with respect to the industry as a whole. For these reasons, the final rule does not establish differentiated bottom ash transport water requirements for units equal to or below 400 MW (or for units equal to or below any other size threshold, other than 50 MW, as explained in Section VIII.C.12).

4. FGMC Wastewater

This rule identifies dry handling as the BAT technology basis for the control of pollutants in FGMC wastewater. More specifically, the technology basis for BAT is a dry vacuum system that employs a mechanical exhauster to convey the FGMC waste (via a change in air pressure) from hoppers directly to a silo. Dry handling of FGMC waste is available and well demonstrated in the industry; indeed, nearly all plants with FGMC systems use dry handling systems. Plants using sorbent injection systems (*e.g.,* activated carbon injection) to reduce mercury emissions from the flue gas typically handle the spent sorbent in the same manner as their fly ash (see Section VI.B.4 and TDD Section 7.5). As of 2009, 92 percent of the industry generating FGMC waste uses dry handling to manage it. Only a few plants use wet systems to transport the spent sorbent to disposal in surface impoundments. Based on the industry survey, the plants using wet handling systems operate them as closed-loop systems and do not discharge FGMC wastewater, or they already have a dry handling system that is capable of achieving zero discharge. Under the zero discharge limitation, these plants could choose to continue to operate their wet systems as closed-loop systems, or they could convert to dry handling technologies by managing the fly ash and spent sorbent together in a retrofitted dry system (rather than an impoundment) or by installing dedicated dry handling equipment for the FGMC waste similar to the equipment used for fly ash.

EPA decided that it would not be appropriate to establish BAT limitations for FGMC wastewater based on surface impoundments for the same reasons (where applicable) that it did not identify surface impoundments as BAT for FGD wastewater (see Section VIII.C.1).

5. Gasification Wastewater

This rule identifies evaporation as the BAT technology basis for the control of pollutants in gasification wastewater. More specifically, the technology basis for BAT is an evaporation system using a falling-film evaporator (or brine concentrator) to produce a concentrated wastewater stream (brine) and a reusable distillate stream. This evaporation technology is available and well demonstrated in the industry for treatment of gasification wastewater. All three IGCC plants now operating in the U.S. (the only existing sources of gasification wastewater) use evaporation technology to treat their gasification wastewater.

EPA did not identify surface impoundments as BAT for gasification wastewater for the same reasons (where applicable) that it did not identify surface impoundments as BAT for FGD wastewater (see Section VIII.C.1). In addition, one existing IGCC plant previously used a surface impoundment to treat its gasification wastewater, and the impoundment effluent repeatedly exceeded its NPDES permit effluent limitations necessary to meet applicable WQS. Because of the demonstrated inability of surface impoundments to remove the pollutants of concern, and given that current industry practice is treatment of gasification wastewater using evaporation, EPA concluded that surface impoundments do not represent BAT for gasification wastewater.

EPA also considered including cyanide treatment as part of the technology basis for BAT (as well as NSPS, PSES, and PSNS) for gasification wastewater. EPA is aware that the Edwardsport IGCC plant, which began commercial operation in June 2013, includes cyanide destruction as one step

[25] Neither these savings nor the fuel and emissions reductions have been incorporated into EPA's analyses for this final rule.

[26] At the same time, costs per amount of energy produced do begin to increase very dramatically as one moves from units above 50 MW to units that are equal to 50 MW and smaller, and thus for reasons described in Section VIII.C.12, the final rule establishes different requirements for units of 50 MW or less for several wastestreams, including bottom ash transport water.

in the treatment process for gasification wastewater. EPA, however, does not currently have sufficient data with which to calculate possible ELGs for cyanide. Thus, EPA decided not to establish cyanide limitations or standards for gasification wastewater in this rule. This decision does not preclude permitting authorities from setting more stringent effluent limitations where necessary to meet WQS. In those cases, plants may elect to install additional treatment, like cyanide destruction, to meet water quality-based effluent limitations.

6. Combustion Residual Leachate

EPA received public comments expressing concern that the proposed definition of combustion residual leachate would apply to contaminated stormwater. Although this was not the Agency's intention, for the final rule, EPA revised the definition to make it clear that contaminated stormwater does not fall within the final definition of combustion residual leachate. This rule identifies surface impoundments as the BAT technology basis for control of pollutants in combustion residual leachate. Based on surface impoundments, which relies on gravity to remove particulates, this rule establishes a BAT limitation on TSS in combustion residual leachate equal to the previously promulgated BPT limitation on TSS in low volume waste sources. Few steam electric power plants currently employ technologies other than surface impoundments for treatment of combustion residual leachate. Throughout the development of this rule, EPA considered whether technologies in place for treatment of other wastestreams at steam electric power plants and wastestreams generated by other industries, including chemical precipitation, could be used for combustion residual leachate. At proposal, noting the small amount of pollutants in combustion residual leachate relative to other significant wastestreams at steam electric power plants, and that this was an area ripe for innovation, EPA requested additional information related to cost, pollutant reduction, and effectiveness of chemical precipitation and alternative approaches to treat combustion residual leachate. Commenters did not provide information that EPA could use to establish BAT limitations. Thus, EPA decided not to finalize BAT limitations for combustion residual leachate based on chemical precipitation (Option E). The record demonstrates that the amount of pollutants collectively discharged in combustion residual leachate by steam electric power plants is a very small portion of the pollutants discharged collectively by all steam electric power plants (approximately 3 percent of baseline loadings, on a toxic-weighted basis). Given this, and the fact that this rule regulates the wastestreams representing the three largest sources of pollutants from steam electric power plants (including by setting a zero discharge standard for two out of the three wastestreams), EPA decided that this rule already represents reasonable further progress toward the CWA's goals. The final rule, therefore, establishes BAT limitations for combustion residual leachate equal to the BPT limitation on TSS for low volume waste sources.

7. Timing

As part of the consideration of the technological availability and economic achievability of the BAT limitations in the rule, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the rule's requirements. As described in greater detail in Section XVI.A.1, where BAT limitations in this rule are more stringent than previously established BPT limitations, those limitations do not apply until a date determined by the permitting authority that is as soon as possible beginning November 1, 2018 (approximately three years following promulgation of this rule), but that is also no later than December 31, 2023 (approximately eight years following promulgation).

Consistent with the proposal and supported by many commenters, the final rule takes this approach in order to provide the time that many facilities need to raise capital, plan and design systems, procure equipment, and construct and then test systems. It also allows for consideration of plant changes being made in response to other Agency rules affecting the steam electric industry (see Section V.B). Moreover, it enables facilities to take advantage of planned shutdown or maintenance periods to install new pollution control technologies.[27] EPA's decision is also designed to allow, more broadly, for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability, something that public commenters urged EPA to consider. In addition, as requested by industry and states, this final rule and preamble clarify how the ''as soon as possible date'' is determined and implemented for steam electric power plants. The final rule specifies the factors that the permitting authority must consider in determining the ''as soon as possible'' date, and Section XVI.A.1 provides guidance on implementation with respect to timing. In addition, the rule includes a ''no later than'' date of December 31, 2023, for implementation because, as public commenters pointed out, without such a date, implementation could be substantially delayed, and a firm ''no later than'' date creates a more level playing field across the industry. EPA's economic analysis assumes prompt renewal of permits (no permits will be administratively continued) and, thus, that the requirements of the rule will be fully implemented by 2023. While some commenters requested that EPA give permitting authorities the ability to extend the implementation period beyond December 31, 2023, in light of public comments received on the proposal, and the fact that plants can reasonably be expected to meet the new ELGs by December 31, 2023, this timeframe is appropriate given the CWA's pollutant discharge elimination goals (see CWA section 101(a)).

8. Legacy Wastewater

For purposes of the BAT limitations in this rule, this preamble uses the term ''legacy wastewater'' to refer to FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, or gasification wastewater generated prior to the date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023 (see Section VIII.C.7). Under this rule, legacy wastewater must comply with specific BAT limitations, which EPA is setting equal to the previously promulgated BPT limitations on TSS in the discharge of fly ash transport water, bottom ash transport water, and low volume waste sources.

EPA did not establish zero discharge BAT limitations for legacy wastewater because technologies that can achieve zero discharge (such as the ones on which the final BAT requirements discussed in Sections VIII.C.2, 3, and 4, above, are based) are not shown to be available for legacy wastewater. Legacy wastewater already exists in wet form, and thus dry handling could not be used eliminate its discharge. Furthermore, EPA lacks data to show that legacy wastewater could be reliably incorporated into a closed-loop process that eliminates discharges, given the variation in operating practices among

[27] EPA's record demonstrates that plants typically have one or two planned shut-downs annually and that the length of these shutdowns is more than adequate to complete installation of relevant treatment and control technologies.

surface impoundments containing legacy wastewater.

EPA also decided not to establish BAT limitations for legacy wastewater based on a technology other than surface impoundments (chemical precipitation, chemical precipitation plus biological treatment, evaporation) because it does not have the data to do so. Data are not available because of the way that legacy wastewater is currently handled at plants.

The vast majority of plants combine some of their legacy wastewater with each other and with other wastestreams, including cooling water, coal pile runoff, metal cleaning wastes, and low volume waste sources in surface impoundments.[28] Once combined in surface impoundments, the legacy wastewater no longer has the same characteristics that it did when it was first generated. For example, the addition of cooling water can dilute legacy wastewater to a point where the pollutants are no longer present at treatable levels. Additionally, some wastestreams have significant variations in flow, such as metal cleaning wastes, which are generally infrequently generated, or coal pile runoff, which is generated during precipitation events. Because surface impoundments are typically open, with no cover, they also receive direct precipitation. As a result of all of this, the characteristics of legacy wastewater contained in surface impoundments (flow rate and pollutant concentrations) vary at both any given plant, as well as across plants nationwide. Furthermore, EPA generally would like to have enough performance data at a well-designed, well-operated plant or plants to derive limitations and standards using its well-established and judicially upheld statistical methodology. In this case, except in limited circumstances, plants do not treat the legacy wastewater that they send to an impoundment using anything beyond the surface impoundment itself.[29] Thus, the final rule establishes BAT limitations for legacy wastewater equal to the previously promulgated BPT limitations on TSS in discharges of fly ash transport water, bottom ash transport water, and low volume waste sources.

Finally, while there are a few plants that discharge from an impoundment containing only legacy FGD wastewater,[30] EPA rejected establishing requirements for such legacy FGD wastewater based on a technology other than surface impoundments. EPA determined that, while it could be possible for plants to treat the legacy FGD wastewater with the same technology used to treat FGD wastewater subject to the BAT limitations described in Section VIII.C.1 (because their characteristics could be similar), establishing requirements based on any technology more advanced than surface impoundments for these legacy ''FGD-only'' wastewater impoundments could encourage plants to alter their operations prior to the date that the final limitations apply in order to avoid the new requirements. Likely, a plant would begin commingling other process wastewater with their legacy FGD wastewater in the impoundment so that any legacy ''FGD-only'' wastewater requirements would no longer apply. Alternatively, plants might choose to pump the legacy FGD wastewater out of the impoundment on an accelerated schedule and prior to the date that the final limitations apply. In this case, the more rapid discharge of the wastewater could result in temporary increases in environmental impacts (*e.g.,* exceedances of WQC for acute impacts to aquatic life). EPA wanted to avoid creating such incentives in this rule, and it therefore decided to establish BAT limitations for discharges of legacy FGD wastewater based on the previously promulgated BPT limitations on TSS for low volume waste sources. Finally, EPA notes that, as a result of the zero discharge requirements for discharges of all pollutants in three wastestreams (fly ash transport water, bottom ash transport water, and flue gas mercury control wastewater), this rule provides strong incentives for steam electric power plants to greatly reduce, if not completely eliminate, the disposal and treatment of their major sources of ash-containing wastewater in surface impoundments. As a result, EPA anticipates that overall volumes of legacy wastewater will continue to decrease dramatically over time, as this rule becomes fully implemented.

9. Economic Achievability

EPA's analysis for the final BAT limitations demonstrates that they are economically achievable for the steam electric industry as a whole, as required by CWA section 301(b)(2)(A). EPA performed cost and economic impact assessments using the Integrated Planning Model (IPM) using a baseline that reflects impacts from other relevant environmental regulations (see RIA).[31] For the final rule, the model showed very small additional effects on the electricity market, on both a national and regional sub-market basis. Based on the results of these analyses, EPA estimated that the requirements associated with the final rule would result in a net reduction of 843 MW in steam electric generating capacity as of the model year 2030, reflecting full compliance by all plants. This capacity reduction corresponds to a net effect of two unit closures or, when aggregating to the level of steam electric generating plants, and net plant closure.[32] These IPM results support EPA's conclusion that the final rule is economically achievable.

10. Non-Water Quality Environmental Impacts, Including Energy Requirements [33]

The final BAT effluent limitations have acceptable non-water quality

[28] For example, there are 65 plants for which EPA estimated FGD wastewater compliance costs and that use an impoundment as part of their treatment system. For 54 of the 65 plants (83 percent), the FGD wastewater is commingled with, at least, fly and/or bottom ash transport water, and for another eight of the 65 plants (12 percent), the FGD wastewater is commingled with non-ash wastewater, such as cooling tower blowdown or low volume waste sources. DCN SE05875.

[29] For example, no plant uses biological treatment or evaporation to treat its legacy fly ash transport water or legacy bottom ash transport water contained in an impoundment, including any impoundment that may contain only legacy fly ash transport water or only legacy bottom ash transport water. Although EPA identified fewer than ten plants that use chemical precipitation to treat wastewater that contains, among other things, ash transport water, EPA does not have any data to characterize the effluent from these systems. Thus, no steam electric industry data exist to establish BAT limitations for possible ''fly ash-only'' impoundments or ''bottom ash-only'' impoundments based on these technologies.

[30] EPA determined that there are three plants that are estimated to incur FGD wastewater compliance costs and that use an impoundment as part of the treatment system, but where the FGD wastewater is not commingled with other process wastewaters in the impoundment. There are no plants that discharge from an impoundment containing only gasification wastewater.

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

[32] Given the design of IPM, unit-level and thereby plant-level projections are presented as an indicator of overall regulatory impact rather than a precise prediction of future unit–level or plant-specific compliance actions.

[33] As described in Section VIII.C.13, this rule includes a voluntary incentives program that provides the certainty of more time for plants to implement new BAT requirements, if they adopt additional process changes and controls that achieve limitations on mercury, arsenic, selenium, and TDS in FGD wastewater, based on evaporation technology. The information presented in this section assumes plants will choose to comply with BAT limitations for FGD wastewater based on chemical precipitation and biological treatment. EPA does not know how many plants will opt into the voluntary incentives program. Therefore, EPA also calculated non-water quality environmental impacts assuming all plants will elect to comply with the voluntary incentives program and similarly found these impacts to be acceptable. See DCN SE05051.

environmental impacts, including energy requirements. Section XII describes in more detail EPA's analysis of non-water quality environmental impacts and energy requirements. EPA estimates that by year 2023, under the final rule and reflecting full compliance, energy consumption increases by less than 0.01 percent of the total electricity generated by power plants. EPA also estimates that the amount of fuel consumed by increased operation of motor vehicles (*e.g.*, for transporting fly ash) increases by approximately 0.002 percent of total fuel consumption by all motor vehicles.

EPA also evaluated the effect of the BAT effluent limitations on air emissions generated by all electric power plants (NO_X, sulfur oxides (SO_X), and CO_2), solid waste generation, and water usage. Under the final rule, NO_X emissions are projected to decrease by 1.16 percent, SO_X emissions are projected to increase by 0.04 percent, and CO_2 emissions are projected to decrease by 0.106 percent due to changes in the mix of electricity generation (*e.g.*, less electricity from coal-fired steam electric generating units and more electricity from natural gas-fired steam electric generating units). Moreover, solid waste generation is projected to increase by less than 0.001 percent of total solid waste generated by all electric power plants. Finally, EPA estimates that the final rule has a positive impact on water withdrawal, with steam electric power plants reducing the amount of water they withdraw by 57 billion gallons per year (155 million gallons per day).

11. Impacts on Residential Electricity Prices and Low-Income and Minority Populations

EPA examined the effects of the final rule on consumers as an additional factor that might be appropriate when considering what level of control represents BAT. If all annualized compliance costs were passed on to residential consumers of electricity, instead of being borne by the operators and owners of power plants (a very conservative assumption), the average monthly increase in electricity bill for a typical household would be no more than $0.12 under the final rule.

EPA also considered the effect of the rule on minority and low-income populations. As explained in Section XVII.J, using demographic data regarding who resides closest to steam electric power plant discharges and who consumes the most fish from waters receiving power plant discharges, EPA concluded that low-income and minority populations benefit to an even greater degree than the general population from the reductions in discharges associated with the final rule.

12. Existing Oil-Fired and Small Generating Units

EPA considered whether subcategorization of the ELGs was warranted based on the factors specified in CWA section 304(b)(2)(B) (see Section IV.B.3 and TDD Section 5). Ultimately, EPA concluded that it would be appropriate to set different limitations for existing small generating units (50 MW or less) and existing oil-fired generating units. No other, different requirements were warranted for this rule under the factors considered.

Oil-Fired Generating Units. For oil-fired generating units, the final rule establishes BAT effluent limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater equal to previously established BPT limitations on TSS in fly ash transport water, bottom ash transport water, and low volume waste sources. As defined in the rule, oil-fired generating units refer to those that use oil as either the primary or secondary fuel and do not burn coal or petroleum coke. Units that use only oil during startup or for flame stabilization are not considered oil-fired generating units.

EPA decided to finalize these limitations for oil-fired generating units because EPA's record demonstrates that, in comparison to coal- and petroleum coke-fired units, oil-fired units generate substantially fewer pollutants, are generally older and operate less frequently, and in many cases are more susceptible to early retirement when faced with compliance costs attributable to the final rule.

The amount of ash generated by oil-fired units is a small fraction of the amount produced by coal-fired units. Coal-fired units generate hundreds to thousands of tons of ash each day, with some plants generating more than 2,000 tons per day of ash. In contrast, oil-fired units generate less than ten tons of ash per day. This disparity is also apparent when comparing the ash tonnage to the amount of power generated, with coal-fired units producing nearly 1,800 times more ash than oil-fired units (0.6 tons per MW-hour on average for coal units; 0.000319 tons per MW-hour on average for oil units). The amount of pollutants discharged to surface waters is roughly correlated to the amount of ash wastewater discharged; thus, oil-fired generating units discharge substantially fewer pollutants to surface waters than coal-fired units, even when generating the same amount of electricity. EPA estimates that the amount of pollutants discharged collectively by all oil-fired generating units is a very small portion of the pollutants discharged collectively by all steam electric power plants (less than one percent, on a toxic-weighted basis).

Oil-fired generating units are generally among the oldest steam electric units in the industry. Eighty-seven percent of the units are more than 25 years old. In fact, more than a quarter of the units began operation more than 50 years ago. Based on responses to the industry survey, fewer than 20 oil-fired generating units discharged fly ash or bottom ash transport water in 2009. This is likely because only about 20 percent of oil-fired generating units operate as baseload units; the rest are either cycling/intermediate units (about 45 percent) or peaking units (about 35 percent). These units also have notably low capacity utilization. While about 30 percent of the baseload units report capacity utilization greater than 75 percent, almost half report a capacity utilization of less than 25 percent. Eighty percent of the cycling/intermediate units and all peaking units also report capacity utilization less than 25 percent. Thirty-five percent of oil-fired generating units operated for more than six months in 2009; nearly half of the units operated for fewer than 30 days.

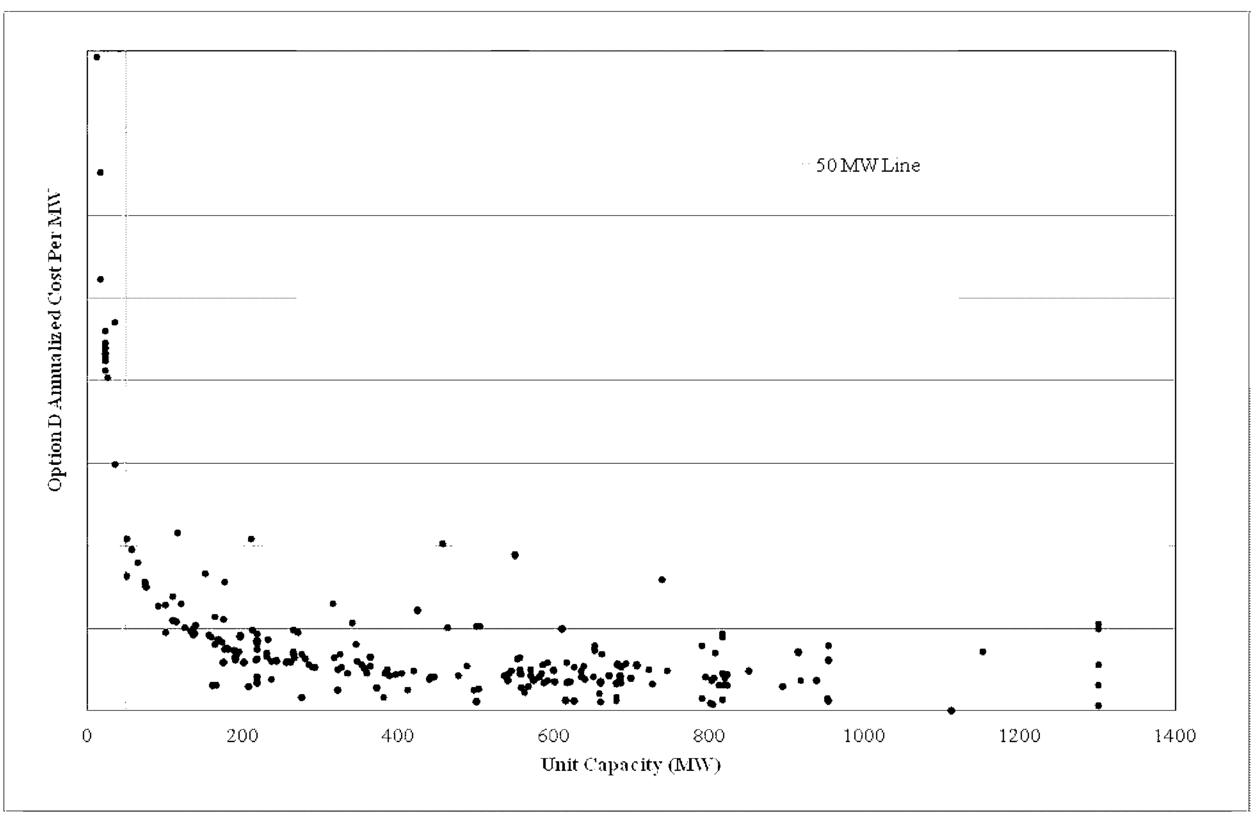
While these older and generally intermittently operated oil-fired generating units are capable of installing and operating the treatment technologies that form the bases for this rule, and the costs would be affordable for most plants, EPA concludes that, due to the factors described here, companies may choose to shut down these oil-fired units instead of making new investments to comply with the rule. If these units shut down, EPA is concerned about resulting reductions in the flexibility that grid operators have during peak demand due to less reserve generating capacity to draw upon. But, more importantly, maintaining a diverse fleet of generating units that includes a variety of fuel sources is important to the nation's energy security. Because the supply/delivery network for oil is different from other fuel sources, maintaining the existence of oil-fired generating units helps ensure reliable electric power generation, as commenters confirmed. EPA considered these potential impacts on electric grid reliability and the nation's energy security, under CWA section 304(b)(2)(B), in its decision to establish different BAT limitations for oil-fired generating units.

Small Generating Units. The final rule also establishes BAT effluent limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification water at small generating units equal to previously established BPT limitations on TSS for fly ash transport water, bottom ash transport water, and low volume waste sources. For purposes of this rule, small generating units refer to those units with a total nameplate generating capacity of 50 MW or less. EPA decided to establish these different BAT limitations for small units because they are more likely to incur compliance costs that are significantly and disproportionately higher per amount of energy produced (dollars per MW) than those incurred by larger units.

Some commenters stated that the cost to a unit in terms of dollars per MW is not relevant because BAT should be established at a level at which the costs are affordable to the industry as a whole. They noted that EPA's IPM analysis demonstrates that the most stringent proposed regulatory option is economically achievable for all units above 50 MW. Other commenters supported EPA's consideration of the relative magnitude of costs for smaller units compared to larger units, and some suggested EPA should increase the size threshold to 100 MW because those units also have disproportionate costs per amount of energy produced, and they collectively discharge a small fraction of the total pollutants discharged by all steam electric power plants.

EPA reviewed the record and re-evaluated the threshold for small units in light of comments and the key changes since proposal discussed in Section V. EPA considered establishing no threshold, as well as several different size thresholds, for small units. The Agency looked closely at establishing a threshold at 50 MW or 100 MW. While the total amount of pollutants discharged by units at these thresholds is relatively small in comparison to those discharged by all steam electric power plants, the amount of pollutants discharged by units smaller than or equal to 100 MW is almost double the amount of pollutants discharged by units smaller than or equal to 50 MW. See DCN SE05813 for specific information on these pollutant discharges. The record indicates that the cost per unit of energy produced increases as the size of the generating unit decreases, and while there is no clear ''knee of the curve'' at which to establish a size threshold, there is a difference between units at 50 MW and below compared to those above 50 MW. Figure VIII–1, below, shows the annualized cost per amount of energy produced for existing units under Regulatory Option D. Figure VIII–1 shows that the cost per amount of energy produced increases as the size of the generating unit decreases. Annualized cost per amount of energy produced increases gradually as one moves from the very largest units down to 100 MW, and then the cost per amount of energy produced begins to increase more rapidly as one moves from 100 MW down to 50 MW, until it increases very rapidly for units at 50MW and below. Additionally, Figure VIII–1 shows that nearly all of the ratios of cost to amount of energy produced for units smaller than or equal to 50 MW are above those for the entire population of remaining units. The same cannot be said of the ratio for units smaller than or equal to 100 MW.

Figure VIII-1. Regulatory Option D Annualized Cost per MW Compared to Unit Capacity (MW)



In light of the fact that the costs per amount of energy produced are significantly and disproportionately higher for units smaller than or equal to 50 MW compared to larger units, and in light of the very small fraction of pollutants discharged by units smaller than or equal to 50 MW, EPA ultimately decided to establish different requirements for units at this threshold. Keeping in mind the statutory directive to set effluent limitations that result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants (CWA section 301(b)(2)(A)), EPA used its best judgment to balance the competing interests. EPA recognizes that any attempt to establish a size threshold for generating units will be imperfect due to individual differences across units and firms. EPA concludes, however, that a threshold of 50 MW or less reasonably and effectively targets those generating units that should receive different treatment based on the considerations described above, while advancing the CWA's goals. Furthermore, as shown in Section IX.C, EPA's analysis demonstrates that the final rule, with a threshold established at 50 MW, is economically achievable.

13. Voluntary Incentives Program

As part of the BAT for existing sources, the final rule establishes a voluntary incentives program that provides the certainty of more time (until December 31, 2023) for plants to implement new BAT requirements, if they adopt additional process changes and controls that achieve limitations on mercury, arsenic, selenium, and TDS in FGD wastewater, based on evaporation technology (see Section VIII.C.1 for a more complete description of the evaporation technology basis). This optional program offers significant environmental protections beyond those achieved by the final BAT limitations for FGD wastewater based on chemical precipitation plus biological treatment because evaporation technology is capable of achieving significant removals of toxic metals, as well as TDS.[34]

EPA's proposal included a voluntary incentives program that contained, as one element, incentives in the form of additional implementation time for plants that eliminate the discharge of all process wastewater (except cooling water). Public commenters urged EPA to consider establishing, instead, a program that provided incentives for plants that go further than the rule's requirements to reduce discharges from individual wastestreams. Because the final rule already contains zero discharge limitations for several key wastestreams, EPA decided that the voluntary incentives program should focus on FGD wastewater.

EPA concluded that additional pollutant reductions could be achieved under a voluntary incentives program because there are certain reasons a plant might opt to treat its FGD wastewater using evaporation rather than chemical precipitation plus biological treatment. One such reason is the possibility that a plant's NPDES permit may need more stringent limitations necessary to meet applicable WQS. For example, some power plant discharges containing TDS (including bromide) that occur upstream of drinking water treatment plants can negatively impact treatment of source waters at the drinking water treatment plants. A recent study identified four drinking water treatment plants that experienced increased levels of bromide in their source water, and corresponding increases in the formation of carcinogenic disinfection by-products (brominated DPBs) in the finished drinking water, after the installation of wet FGD scrubbers at upstream steam electric power plants (DCN SE04503).

Furthermore, based on trends in the industry and experience with this and other industries, EPA expects that, over time, the costs of evaporation (and other technologies that could achieve the limitations in the voluntary incentives program, including zero discharge practices) will decrease so as to make it an even more attractive option for plants. EPA understands that vendors are already working on changes to this technology to reduce the costs, reduce the amount of solids generated, and improve the solids handling. See TDD Section 7.1.4.

The technology on which the BAT limitations in the voluntary incentives program are based, evaporation, is available to steam electric power plants. EPA identified three plants in the U.S. that have installed, and one plant that is in the process of installing, evaporation systems to treat their FGD wastewater. Four coal-fired power plants in Italy treat FGD wastewater using evaporation. See TDD Section 7. Furthermore, the voluntary program is economically achievable because only those plants that opt to be subject to the BAT limitations based on evaporation, rather than the BAT limitations based on chemical precipitation plus biological treatment, must achieve them. Therefore, any plant that chooses to be subject to the more stringent limitations has determined for itself, in light of its own financial information and economic outlook, that such limitations are economically achievable. Finally, EPA analyzed the non-water quality environmental impacts and energy requirements associated with the voluntary incentives program, and it found them acceptable. See DCN SE05574.

The development of this voluntary incentives program furthers the CWA's ultimate goal of eliminating the discharge of pollutants into the Nation's waters. See CWA section 101(a)(1) and section 301(b)(2)(A) (specifying that BAT will result in ''reasonable further progress toward the national goal of eliminating the discharge of pollutants''). While the final rule's BAT limitations based on chemical precipitation plus biological treatment represent ''reasonable further progress,'' the voluntary incentives program is designed to press further toward achieving the national goal of the Act, as wastewater that has been treated properly using evaporation has very low pollutant concentrations (also making it possible to reuse the wastewater and completely eliminate the discharge of any pollutants). In addition, CWA section 104(a)(1) gives the Administrator authority to establish national programs for the prevention, reduction, and elimination of pollution, and it provides that such programs shall promote the acceleration of research, experiments, and demonstrations relating to the prevention, reduction, and elimination of pollution. EPA anticipates that the voluntary incentives program will effectively accelerate the research into and demonstration of controls and processes intended to prevent, reduce, and eliminate pollution because, under it, plants will opt to employ control and treatment strategies to significantly reduce discharges of pollutants found in FGD wastewater.

Steam electric power plants agreeing to meet BAT limitations for FGD wastewater based on evaporation must comply with those limitations on arsenic, mercury, selenium, and TDS in FGD wastewater.[35] For such plants, the BAT limitations based on evaporation apply as of December 31, 2023, to FGD wastewater generated on and after December 31, 2023. Plants opting to participate in the voluntary program can use the period in advance of this date to research, engineer, design, procure, construct, and optimize systems capable

[34] Properly operated evaporation systems are also capable of achieving the BAT limitations based on chemical precipitation plus biological treatment.

[35] For some plants, proper pretreatment such as softening or chemical precipitation is likely appropriate to ensure effective and efficient operation of evaporation systems.

of meeting the limitations based on evaporation.

For purposes of the voluntary incentives program BAT limitations, legacy FGD wastewater is FGD wastewater generated prior to December 31, 2023. For such legacy FGD wastewater, the final rule establishes BAT limitations on TSS in discharges of FGD wastewater that are equal to BPT limitations for low volume waste sources.

EPA decided not to make the voluntary incentives program available to plants that send their FGD wastewater to POTWs. Under CWA section 307(b)(1), PSES must specify a time for compliance that does not exceed three years from the date of promulgation, and thus the additional time of up to 2023 cannot be given to indirect dischargers. Of course, nothing prohibits an indirect discharger from using any technology, including evaporation, to comply with the final PSES and PSNS.

EPA expects that any plant interested in the voluntary incentives program would indicate their intent to opt into the program prior to issuance of its next NPDES permit, following the effective date of this rule. A plant can indicate its intent to opt into the voluntary program on its permit application or through separate correspondence to the NPDES Director, as long as the signatory requirements of 40 CFR 122.22 are met.

D. Best Available Demonstrated Control Technology/NSPS

After considering all of the technologies described in this preamble and TDD Section 7, as well as public comments, and in light of the factors specified in CWA section 306 (see Section IV.B.4), EPA concluded that the technologies described in Option F represent BADCT for steam electric power plants, and the final rule promulgates NSPS based on that option. Thus, the final NSPS establish: (1) Standards on arsenic, mercury, selenium, and TDS in FGD wastewater, based on evaporation (same basis as for BAT limitations in voluntary incentives program); (2) a zero discharge standard on all pollutants in bottom ash transport water, based on dry handling or closed-loop systems (same bases as for BAT limitations); (3) a zero discharge standard on all pollutants in FGMC wastewater, based on dry handling (same basis as for BAT limitations); (4) standards on mercury, arsenic, selenium, and TDS in gasification wastewater, based on evaporation technology (same basis as for BAT limitations); and (5) standards on mercury and arsenic in discharges of combustion residual leachate, based on chemical precipitation (more specifically, the technology basis is a chemical precipitation system that employs hydroxide precipitation, sulfide precipitation, and iron coprecipitation to remove heavy metals). The final rule also maintains the previously established zero discharge NSPS on discharges of fly ash transport water, based on dry handling.

The record indicates that the technologies that serve as the bases for the final NSPS are well demonstrated based on the performance of plants using the technologies. For example, new steam electric power generating sources have been meeting the previously established zero discharge standard for fly ash transport water since 1982, predominantly through the use of dry handling technologies. Moreover, as described in Section VIII.C.13, three plants in the U.S. and four plants in Italy use evaporation technology to treat their FGD wastewater, and another U.S. plant is in the process of installing such technology for that purpose. Of the approximately 50 coal-fired generating units that were built within the last 20 years, most (83 percent) manage their bottom ash without using water to transport the ash and, as a result, do not discharge bottom ash transport water. The technology basis identified as BAT technology for gasification wastewater represents current industry practice. Every IGCC power plant currently in operation uses evaporation to treat their gasification wastewater, even when the wastewater is not discharged and is instead reused at the plant. In the case of FGMC wastewater, every plant currently using post-combustion sorbent injection (*e.g.*, activated carbon injection) either handles the captured spent sorbent with a dry process or manages the FGMC wastewater so that it is not discharged to surface waters (or has the capability to do so). For combustion residual leachate, chemical precipitation is a well-demonstrated technology for removing metals and other pollutants from a variety of industrial wastewaters, including leachate from landfills not located at power plants. Chemical precipitation is also well demonstrated at steam electric power plants for treatment of FGD wastewater that contains the pollutants in combustion residual leachate.

The NSPS in the final rule pose no barrier to entry. The cost to install technologies at new units is typically less than the cost to retrofit existing units. For example, the cost differential between Options B, C, and D for existing sources is mostly associated with retrofitting controls for bottom ash handling systems. For new sources, however, NSPS based on Option F do not present plants with the same choice of retrofit versus modification of existing processes. This is because every new generating unit must install some type of bottom ash handling system as the unit is constructed. Establishing a zero discharge standard for all pollutants in bottom ash transport water as part of the NSPS means that power plants will install a dry bottom ash handling system during construction instead of installing a wet-sluicing system.

Moreover, EPA assessed the possible impacts of the final NSPS on new sources by comparing the incremental costs of the Option F technologies to the costs of hypothetical new generating units. EPA is not able to predict which plants might construct new units or the exact characteristics of such units. Instead, EPA calculated and analyzed compliance costs for a variety of plant and unit configurations. EPA developed NSPS compliance costs for new sources using a methodology similar to the one used to develop compliance costs for existing sources. EPA's estimates for compliance costs for new sources are based on the net difference in costs between wastewater treatment system technologies that would likely have been implemented at new sources under the previously established regulatory requirements, and those that would likely be implemented under the final rule. EPA estimated that the incremental compliance costs for a new generating unit (capital and O&M) represent approximately 3.3 percent of the annualized cost of building and operating a new 1,300 MW coal-fired plant, with capital costs representing 0.3 to 2.8 percent of the overnight construction costs, and annual O&M costs representing 0.3 to 3.9 percent of the fuel and other O&M cost of operating a new plant.

Finally, EPA analyzed the non-water quality environmental impacts and energy requirements associated with Option F for both existing and new sources. See DCN SE05952 and DCN SE05951. Since there is nothing inherently different between an existing and new source, EPA's analysis with respect to existing sources is instructive. Using both of these analyses, EPA determined that NSPS based on the Option F technologies have acceptable non-water quality environmental impacts and energy requirements.

In contrast to the BAT effluent limitations, this rule establishes the same NSPS for oil-fired generating units and small generating units as for all other new sources. A key factor that affects compliance costs for existing sources is the need to retrofit new pollution controls to replace existing pollution controls. New sources do not incur retrofit costs because the pollution controls (process operations or treatment technology) are installed at the time of construction. Thus the costs for new sources are lower, even if the pollution controls are identical.

For each of the wastestreams except combustion residual leachate, EPA rejected establishing NSPS based on surface impoundments for the same reasons it rejected establishing BAT based on surface impoundments. For FGD wastewater, EPA also did not establish NSPS based on chemical precipitation for the same reasons it rejected establishing BAT based on that technology. In particular, these other technologies would not achieve as much pollutant reduction as the technology bases in Option F—which is technologically available and economically achievable with acceptable non-water quality environmental impacts and energy requirements—and thus do not represent best available demonstrated control technology.

EPA did not select surface impoundments as the basis for NSPS for combustion residual leachate because, unlike BAT, NSPS represent the ''greatest degree of effluent reduction . . . achievable'' (CWA section 306), and (besides ''cost'' and ''any non-water quality environmental impact and energy requirements,'' discussed above) EPA does not consider ''other factors'' in establishing NSPS. When used to treat combustion residual leachate, chemical precipitation can achieve substantial pollutant reductions as compared to surface impoundments. Thus, EPA has determined that NSPS for leachate based on chemical precipitation achieve the ''greatest degree of effluent reduction'' as that term is used in CWA section 306.

Similarly, EPA did not select chemical precipitation plus biological treatment as the basis for NSPS for FGD wastewater because, under CWA section 306, NSPS reflect ''the greatest degree of effluent reduction . . . achievable.'' Evaporation systems are capable of achieving extremely low pollutant discharge levels, and in fact can be the basis for a plant completely eliminating all discharges associated with FGD wastewater. Moreover, unlike EPA's decision not to identify evaporation as the technology basis for FGD wastewater discharges from all existing sources due to the large associated cost, establishing NSPS for FGD wastewater based on evaporation does not add to the overall estimated cost of the rule because EPA does not predict any new coal-fired generating units will be installed in the foreseeable future. As explained above, however, in the event that a new unit is installed, EPA determined that the NSPS compliance costs would not present a barrier to entry.

E. PSES

Table VIII–2 summarizes the results of EPA's pass-through analysis for the regulated pollutants (with numeric limitations) in each wastestream, as controlled by the relevant BAT and NSPS technology bases.[36] As explained in Section VII.C, EPA did not conduct its traditional pass-through analysis for wastestreams with zero discharge limitations or standards. Zero discharge limitations and standards achieve 100 percent removal of pollutants; therefore, all pollutants in those wastestreams pass through the POTW. As shown in the table, all of the pollutants regulated under BAT/NSPS pass through secondary treatment by a POTW.

TABLE VIII–2—SUMMARY OF PASS-THROUGH ANALYSIS RESULTS

Technology basis/Wastewater stream	Pollutant	Pass through? (yes/no)
Chemical Precipitation for Combustion Residual Leachate (only for NSPS)	Arsenic	Yes.
	Mercury	Yes.
Chemical Precipitation plus Biological Treatment for FGD Wastewater	Arsenic	Yes.
	Mercury	Yes.
	Nitrate/Nitrite as N	Yes.
	Selenium	Yes.
Evaporation for FGD wastewater (only for NSPS)	Arsenic	Yes.
	Mercury	Yes.
	Selenium	Yes.
	TDS	Yes.
Evaporation for Gasification Wastewater	Arsenic	Yes.
	Mercury	Yes.
	Selenium	Yes.
	TDS	Yes.

After considering all of the relevant factors and technology options in this preamble and in the TDD, as well as public comments, as is the case with BAT, EPA decided to establish PSES based on the technologies described in Option D. For PSES, the final rule establishes: (1) Standards on arsenic, mercury, selenium and nitrate/nitrite as N in FGD wastewater; (2) a zero discharge standard on all pollutants in fly ash transport water; (3) a zero discharge standard on all pollutants in bottom ash transport water; (4) a zero discharge standard on all pollutants in FGMC wastewater; (5) standards on mercury, arsenic, selenium, and TDS in gasification wastewater. All of the technology bases for the final PSES are the same as those described for the final BAT limitations. The final rule does not establish PSES for combustion residual leachate because TSS does not pass through POTWs.

EPA selected the Option D technologies as the bases for PSES for the same reasons that EPA selected the Option D technologies as the bases for BAT. EPA's analysis shows that, for both direct and indirect dischargers, the Option D technologies are available and economically achievable, and Option D has acceptable non-water quality environmental impacts, including energy requirements (see Sections IX and XII). EPA rejected other options for

[36] The regulation of TSS in combustion residual leachate (based on surface impoundments) under the final BAT limitations is not represented here because TSS is a conventional pollutant that is effectively treated by POTWs (it does not pass through).

PSES for the same reasons that the Agency rejected other options for BAT. Furthermore, for the same reasons that apply to EPA's final BAT limitations for oil-fired generating units and small generating units, and described in Section VIII.C.12, the final rule does not establish PSES that apply to oil-fired generating units and small generating units (50 MW or smaller).[37] Finally, EPA determined that the final PSES prevent pass through of pollutants from POTWs into receiving streams and also help control contamination of POTW sludge.

As with the final BAT effluent limitations, in considering the availability and achievability of the final PSES, EPA concluded that existing indirect dischargers need some time to achieve the final standards, in part to avoid forced outages (see Section VIII.C.7). However, in contrast to the BAT limitations (which apply on a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023), the new PSES apply as of November 1, 2018. Under CWA section 307(b)(1), pretreatment standards shall specify a time for compliance not to exceed three years from the date of promulgation, so EPA cannot establish a longer implementation period. Moreover, unlike requirements on direct discharges, requirements on indirect discharges are not implemented through an NPDES permit and thus are not subject to awaiting the next permit issuance before the limitations are specified clearly for the discharger. EPA has determined that all of the existing indirect dischargers can meet the standards by November 1, 2018, and because there are a handful of indirect dischargers (who would have approximately three years from the date of promulgation to achieve the standards), implementation of the standards by that date would not lead to electricity availability concerns. See RIA.

For purposes of the PSES in this rule, this preamble uses the term ''legacy wastewater'' to refer to FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, or gasification wastewater generated prior to November 1, 2018. For the same reasons that EPA decided to establish BAT limitations on TSS in discharges of legacy wastewater equal to BPT limitations for fly ash transport water, bottom ash transport water, and low volume waste sources, the final rule does not establish PSES for legacy wastewater (see Section VIII.C.8). TSS and the pollutants it represents are effectively treated by, and thus do not pass through, POTWs.

F. PSNS

After considering all of the relevant factors and technology options described in this preamble and TDD Section 7, as well as public comments, as was the case for NSPS, EPA selected the Option F technologies as the bases for PSNS in this rule. As a result, the final PSNS establish: (1) Standards on arsenic, mercury, selenium, and TDS in FGD wastewater; (2) a zero discharge standard on all pollutants in bottom ash transport water; (3) a zero discharge standard on all pollutants in FGMC wastewater; (4) standards on mercury, arsenic, selenium, and TDS in gasification wastewater; and (5) standards on mercury and arsenic in combustion residual leachate. All the technology bases for the final PSNS are the same as those described for the final NSPS. The final rule also maintains the previously established zero discharge PSNS on discharges of fly ash transport water. As with the final NSPS, this rule establishes the same PSNS for oil-fired generating units and small generating units as for all other new sources.

EPA selected the Option F technologies as the bases for PSNS for the same reasons that EPA selected the Option F technologies as the bases for NSPS (see Section VIII.D). EPA's record demonstrates that the technologies described in Option F are available and demonstrated, and Option F does not pose a barrier to entry and has acceptable non-water quality environmental impacts, including energy requirements (see Sections IX and XII). EPA rejected other options for PSNS for the same reasons that the Agency rejected other options for NSPS. And, as with the final PSES, EPA determined that the final PSNS prevent pass through of pollutants from POTWs into receiving streams and also help control contamination of POTW sludge.

G. Anti-Circumvention Provision

The final rule establishes one of the three anti-circumvention provisions that EPA proposed. The one anti-circumvention provision that EPA decided to establish applies only for existing sources to those wastestreams for which this rule established zero discharge limitations or standards. In general, this provision prevents steam electric power plants from circumventing the final rule by moving effluent produced by a process operation for which there is an applicable zero discharge effluent limitation or standard to another plant process operation for discharge.[38] EPA determined it was appropriate to include this provision in the final rule to make clear that, just because a wastestream that is subject to a zero discharge limitation or standard is moved to another plant process, it does not mean that the wastestream ceases being subject to the applicable zero discharge limitation or standard. For example, using fly ash or bottom ash transport water as makeup water for a cooling tower does not relieve a plant of having to meet the zero discharge limitations and standards for fly ash and bottom ash transport water. EPA encourages the reuse of wastewater where appropriate, but not to the extent that it undermines the zero discharge effluent limitations and standards in this rule. Plants are free to reuse their wastewater, so long as the wastewater ultimately complies with the final limitations and standards.

Some public commenters stated that zero discharge effluent limitations and standards for fly ash and bottom ash transport water, together with this anti-circumvention provision, would prohibit water reuse and prevent water withdrawal reduction at steam electric power plants. In general, EPA disagrees with these commenters. Most plants will choose to comply with the requirements for ash transport water by operating either a dry or closed-loop wet-sluicing system to handle their fly and bottom ash, which will eliminate or substantially reduce the amount of water they currently use in the traditional wet-sluicing system. To the extent that a plant currently uses (or was considering using) ash transport water, such as the effluent from an impoundment, as makeup water for processes such as make-up cooling water and would be precluded from doing so because of the anti-circumvention provision in this rule, the plant could merely switch to an alternate source for the makeup water, such as the water that was (prior to implementing the zero discharge requirement for ash transport water) used to sluice fly ash or bottom ash to the impoundment. In other words, the volume of water that is currently used to sluice ash to an impoundment and

[37] Whereas the final rule establishes BAT limitations on TSS in fly ash and bottom ash transport water, FGMC wastewater, FGD wastewater, and gasification wastewater for small generating units and oil-fired generating units, TSS and the pollutants that they represent do not pass through POTWs.

[38] The anti-circumvention provision applies only to limitations and standards established in this final rule. It does not apply to limitations and standards promulgated previously.

subsequently reused as makeup water would no longer be needed to sluice the ash and could instead be directly used as makeup water for the cooling water system or other processes. Because of this, the zero discharge limitations in this rule will not lead to a net increase at the plant and in fact could result in a decrease in water withdrawal. Lastly, a plant is free to reuse ash transport water, and would be in compliance with the anti-circumvention provision, so long as it is used in a process that does not ultimately result in a discharge.

There is one particular type of plant practice that the final rule's anti-circumvention provision does not apply to. Many industry commenters noted that they use ash transport water in their FGD scrubber. They stated that this practice is preferable to using a fresh water source and allows for an overall reduction in source water withdrawals. They further stated that, under the final rule, any wastewater that passes through the scrubber would undergo significant treatment in order to meet the final FGD wastewater limitations and standards. EPA agrees, in part, with these comments. As explained above, EPA does not agree that using wastewater from one industrial process as makeup water in another industrial process necessarily results in a net reduction in water withdrawals. EPA does agree, however, that using wastewater from an industrial process as makeup water in another industrial process may be preferable to using a fresh water source. EPA is mindful of the CWA's pollutant discharge elimination goal, but also wants to promote opportunities for water reuse. Furthermore, as explained in Section V, EPA recognizes the extensive changes in this industry, and it wants to provide flexibility to plants in managing their wastewater and operations, as well as preserve the ability of plants to retain existing approaches where it is consistent with the CWA's goals. While EPA would not choose to promote these considerations where it resulted in no further progress toward the pollutant discharge elimination goal of the Act, in the case of using ash transport water in an FGD scrubber, since any resulting wastewater discharges would still be required to meet BAT or PSES requirements based on either chemical precipitation plus biological treatment or chemical precipitation plus evaporation under this final rule, EPA decided not to apply the anti-circumvention provision to this particular practice.

The final rule does not establish an anti-circumvention provision that would have required internal monitoring to demonstrate compliance with certain numeric limitations and standards. Some public commenters argued that the proposed provision was unduly restrictive, and they stated that EPA already has authority to accomplish the goal of this particular provision, which is to ensure that wastestreams are being treated rather than simply diluted. EPA agrees with these commenters and thus decided that existing rules, along with the guidance in Section XVI.A.4 of this preamble and TDD Section 14, provide appropriate flexibility to steam electric power plants to combine wastestreams with similar pollutants and treatability, while adequately addressing EPA's concern that plants meet the effluent limitations and standards in this rule through treatment and control strategies, rather than through dilution. Furthermore, some commenters raised concerns that the proposed provision would be a disincentive for plants to internally re-use the treated wastewater within the plant, particularly when the re-use eliminates the discharge of the wastewater. For example, they stated that some steam electric power plants might opt to use a wet scrubber's FGD wastewater as reagent make-up for a new dry scrubber in an integrated design which would essentially evaporate the wet FGD wastewater. EPA notes that plants that internally reuse wastestreams for which EPA is establishing numeric limitations and standards (*e.g.,* FGD wastewater) in a way that completely prevents discharge of that wastestream would not be subject to the numeric limitations and standards because they do not discharge the wastewater. EPA is aware of at least one plant that elected to take such an approach as an alternative to meeting NPDES permit limitations by installing wastewater treatment technology. See DCN SE06338. In general, EPA supports such approaches because they result in further progress towards achieving the pollutant discharge elimination goal of the CWA. Moreover, such approaches are favored because they reduce overall water intake needs.

The final rule also does not establish an anti-circumvention provision that would have required permittees to use EPA-approved analytical methods that are sufficiently sensitive to provide reliable, quantified results at levels necessary to demonstrate compliance with the final effluent limitations and standards because another recently promulgated rule already accomplishes this. As public commenters pointed out, EPA was conducting a rulemaking on that topic; and, in August 2014, EPA published a rule requiring the use of sufficiently sensitive analytical test methods when completing any NPDES permit application. Moreover, the NPDES permit authority must prescribe that only sufficiently sensitive methods be used for analyses of pollutants or pollutant parameters under an NPDES permit where EPA has promulgated a CWA method for analysis of that pollutant. That rule clarifies that NPDES applicants and permittees must use EPA-approved analytical methods that are capable of detecting and measuring the pollutants at, or below, the applicable water quality criteria or permit limits.

H. Other Revisions

1. Correction of Typographical Error for PSNS

As EPA proposed to do, the final rule corrects a typographical error in the previously established PSNS for cooling tower blowdown. As is clear from the development document for the 1982 rulemaking, as well as the previously promulgated NSPS for cooling tower blowdown, EPA inadvertently omitted a footnote in the table that appeared in 40 CFR 423.17(d)(1). The footnote reads ''No detectable amount,'' and it applies to the effluent standard for 124 of the 126 priority pollutants contained in chemicals added for cooling tower maintenance. See ''Development Document for Final Effluent Guidelines, New Source Performance Standards and Pretreatment Standards for the Steam Electric Power Generating Point Source Category,'' Document No. EPA 440/1–82/029. November 1982.

2. Clarification of Applicability

In addition, the final rule contains three minor modifications to the wording of the applicability provision in the steam electric power generating ELGs to reflect EPA's longstanding interpretation and implementation of the rule. These revisions do not alter the universe of generating units regulated by the ELGs, nor do they impose compliance costs on the industry. Instead, they remove potential ambiguity in the regulations by revising the text to more clearly reflect EPA's longstanding interpretation.

First, the applicability provision in the previous ELGs stated, in part, that the ELGs apply to ''an establishment primarily engaged in the generation of electricity for distribution and sale. . . .'' 40 CFR 423.10. The final rule revises that phrase to read ''an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation. . . .'' The final rule thus clarifies that certain facilities, such as generating units owned and operated by industrial facilities in other sectors (*e.g.,* petroleum refineries, pulp and paper mills) that have not traditionally been regulated by the steam electric ELGs, are not within the scope of the ELGs. In addition, the final rule clarifies that certain municipally owned facilities that generate and distribute electricity within a service area (such as distributing electric power to municipal-owned buildings), but use accounting practices that are not commonly thought of as a ''sale,'' are subject to the ELGs. Such facilities have traditionally been regulated by the steam electric ELGs.

Second, the final rule clarifies that fuels derived from fossil fuel are within the scope of the ELGs. The previous ELGs stated, in part, that they apply to discharges resulting from the generation of electricity ''which results primarily from a process utilizing fossil-type fuels (coal, oil, or gas) or nuclear fuel. . . .'' 40 CFR 423.10. Because a number of fuel types are derived from fossil fuels, and thus are fossil fuels themselves, the final rule explicitly mentions and gives examples of such fuels. Thus, the rule reads that the ELGs apply to discharges resulting from the operation of a generating unit ''whose generation results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (*e.g.,* petroleum coke, synthesis gas), or nuclear fuel. . . .''

Third, the final rule clarifies the applicability provision to reflect the current interpretation that combined cycle systems are subject to the ELGs. The ELGs apply to electric generation processes that utilize ''a thermal cycle employing the steam water system as the thermodynamic medium.'' 40 CFR 423.10. EPA's longstanding interpretation is that the ELGs apply to discharges from all electric generation processes with at least one prime mover that utilizes steam (and that meet the other applicability factors in 40 CFR 423.10). Combined cycle systems, which are generating units composed of one or more combustion turbines operating in conjunction with one or more steam turbines, are subject to the ELGs. The combustion turbines for a combined cycle system operate in tandem with the steam turbines; therefore, the ELGs apply to wastewater discharges associated with both the combustion turbine and steam turbine portions of the combined cycle system. The final rule, therefore, clarifies that ''[t]his part applies to discharges associated with both the combustion turbine and steam turbine portions of a combined cycle generating unit.''

I. Non-Chemical Metal Cleaning Waste

EPA proposed to establish BAT/NSPS/PSES/PSNS requirements for non-chemical metal cleaning wastes equal to previously established BPT limitations for metal cleaning wastes.[39] EPA based the proposal on EPA's understanding, from industry survey responses, that most steam electric power plants manage their chemical and non-chemical metal cleaning wastes in the same manner. Since then, based in part on public comments submitted by industry groups, the Agency has learned that plants refer to the same operation using different terminology; some classify non-chemical metal cleaning waste as such, while others classify it as low volume waste sources. Because the survey responses reflect each plant's individual nomenclature, the survey results for non-chemical metal cleaning wastes are skewed. Furthermore, EPA does not know the nomenclature each plant used in responding to the survey, so it has no way to adjust the results to account for this. Consequently, EPA does not have sufficient information on the extent to which discharges of non-chemical metal cleaning wastes occur, or on the ways that industry manages their non-chemical metal cleaning wastes. Moreover, EPA also does not have information on potential best available technologies or best available demonstrated control technologies, or the potential costs to industry to comply with any new requirements. Due to incomplete data, some public commenters urged EPA not to establish BAT limitations for non-chemical metal cleaning wastes in this final rule. Ultimately, EPA decided that it does not have enough information on a national basis to establish BAT/NSPS/PSES/PSNS requirements for non-chemical metal cleaning wastes. The final rule, therefore, continues to ''reserve'' BAT/NSPS/PSES/PSNS for non-chemical metal cleaning wastes, as the previously promulgated regulations did.[40]

By reserving limitations and standards for non-chemical metal cleaning waste in the final rule, the permitting authority must establish such requirements based on BPJ for any steam electric power plant discharged non-chemical metal cleaning wastes. As part of this determination, EPA expects that the permitting authority would examine the historical permitting record for the particular plant to determine how discharges of non-chemical metal cleaning waste had been permitted in the past, including whether such discharges had been treated as low volume waste sources or metal cleaning waste. See Section XVI.

J. Best Management Practices

EPA proposed to include BMPs in the ELGs that would require plant operators to conduct periodic inspections of active and inactive surface impoundments to ensure their structural integrity and to take corrective actions where warranted. The proposed BMPs were largely similar to those proposed for the CCR rule, except for the closure requirements. EPA took comments on whether establishment of BMPs was more appropriate under the authority of the Resource Conservation and Recovery Act (RCRA) or the CWA. While some commenters asked EPA to establish BMPs in the final rule, many others urged EPA not to do so, arguing that BMPs are better suited for the CCR rule. Because EPA promulgated BMPs in the CCR rule, to avoid unnecessary duplication, this rule does not establish BMPs.

IX. Costs and Economic Impact

EPA evaluated the costs and associated impacts of the ELGs on existing generating units at steam electric power plants, and on new sources to which the ELGs may apply in the future. See TDD Section 9. This section provides an overview of the methodology EPA used to assess the costs and the economic impacts of the final ELGs and summarizes the results of these analyses. See the RIA for additional detail.

EPA used certain indicators to assess the economic achievability of the ELGs for the steam electric industry as a whole, as required by CWA section 301(b)(2)(A). These values were compared to a baseline described elsewhere in this document. For existing sources, EPA considered the number of generating units and plants expected to close due to the ELGs, and their generating capacity relative to total capacity (see Section IX.C.1.b). Although not used as the sole criterion to determine economic achievability, EPA also analyzed the ratio of compliance costs to revenue to estimate the number of plants and their owning

[39] Under the structure of the previously promulgated regulations, non-chemical metal cleaning wastes are a subset of metal cleaning wastes.

[40] As part of its proposal to establish new BAT/PSES/NSPS/PSNS requirements for non-chemical metal cleaning waste equal to BPT limitations for metal cleaning waste, EPA also proposed an exemption for certain discharges of non-chemical metal cleaning waste, which would be treated as low volume waste sources. Because the final rule does not establish these new requirements, EPA also did not finalize the proposed exemption.

entities that exceed set thresholds indicating potential financial strain; large numbers of such plants or owning entities could suggest that the ELGs may not be economically achievable by the industry (see Section IX.C.1.a). For new sources, EPA considered the magnitude of compliance costs relative to the costs of constructing and operating new coal-fired generating units (Section IX.C.2). In addition to the analyses used to determine economic achievability, EPA conducted other analyses to characterize the potential broader economic impacts of the ELGs (*e.g.,* on entities that own steam electric power plants, electricity rates, employment) and to enable the Agency to meet its requirements under Executive Orders or other statutes (*e.g.,* Executive Order 12866, Regulatory Flexibility Act, Unfunded Mandates Reform Act).

A. Plant-Specific and Industry Total Costs

EPA first estimated plant-specific costs to control discharges at existing generating units at steam electric power plants to which the final ELGs apply (existing sources). For all applicable wastestreams, EPA assessed the operations and treatment system components in place at a given unit in the baseline (or expected to be in place given other existing rules), identified equipment and process changes that the plant would likely make to meet the final ELGs, and estimated the cost to implement those changes. As explained in Section V, since proposal, EPA accounted for additional announced unit retirements, conversions, and relevant operational changes, as well as changes plants are likely to make in response to the CCR and CPP rules. As a result, the number of plants projected to incur non-zero compliance costs is about 50 percent less than that estimated at proposal. As appropriate, EPA also accounted for cost savings associated with these equipment and process changes (*e.g.,* avoided costs to manage surface impoundments). EPA thus derived capital and O&M costs at the plant level for control of each wastestream using the technologies that form the bases for the final rule for existing sources. See the TDD Section 9 for a more detailed description of the methodology EPA used to estimate plant-level costs.

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

EPA calculated total industry costs by applying survey weights to the plant-specific annualized costs and summing them. For the assessment of industry costs, EPA considered costs on both a pre-tax and after-tax basis. Pre-tax annualized costs provide insight on the total expenditure as incurred, while after-tax annualized costs are a more meaningful measure of impact on privately owned for-profit plants, and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. EPA uses pre- and/or after-tax costs in different analyses, depending on the concept appropriate to each analysis (*e.g.,* social costs discussed in Section IX.B are calculated using pre-tax costs whereas cost-to-revenue screening-level analyses discussed in Section IX.C are conducted using after-tax costs). See Table IX–1 for estimates of pre- and post-tax industry costs.

TABLE IX–1—TOTAL ANNUALIZED INDUSTRY COSTS

[In millions, 2013$], 7% Discount Rate

	Pre-tax	After-tax
Total Annualized Industry Costs	$496.2	$339.6

B. Social Costs

Social costs are the costs of the rule from the viewpoint of society as a whole, rather than regulated facilities only. In calculating social costs, EPA tabulated the pre-tax costs in the year when they are estimated to be incurred. EPA assumed that all plants upgrading their systems in order to meet the effluent limitations and standards would do so sometime over a five-year period, during the implementation period for this rule. Given the implementation dates in this rule, and the fact that permitting authorities have to incorporate the final effluent limitations into NPDES permits (which have five-year terms) before they become applicable, this assumption is a reasonable estimate.

EPA performed the social cost analysis over a 24-year analysis period, which combines the length of the period during which plants are anticipated to install the control technologies and the useful life of the longest-lived technology installed at any facility (20 years). EPA calculated social cost of the final rule for existing generating units at steam electric power plants using both a three percent discount rate and an alternative discount rate of seven percent.[41]

Social costs include costs incurred by both private entities and the government (*e.g.,* in implementing the regulation). As described in Section XVII.B, EPA estimates that the final rule will not lead to additional costs to permitting authorities. Consequently, the only category of costs necessary to calculate social costs are those estimated for steam electric power plants.

Table IX–2 presents the total annualized social cost of the final ELGs on existing generating units at seam electric power plants, calculated using three percent and seven percent discount rates.

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

TABLE IX–2—TOTAL ANNUALIZED SOCIAL COSTS

[In millions, 2013$]

	3% Discount rate	7% Discount rate
Total Annualized Social Costs	$479.5	$471.2

The value presented in Table IX–2 for the seven percent discount rate is slightly lower than the comparable industry costs (pre-tax) in Table IX–1 (*e.g.,* $471.2 million versus $496.2 million) due to the inclusion of the timing of expenditures in the annualized social costs calculations.

C. Economic Impacts

EPA assessed the economic impacts of this rule in two ways: (1) A screening-level assessment of the cost impacts on existing generating units at steam electric power plants units and the entities that own those plants, based on comparison of costs to revenue; and (2) an assessment of the impact of this rule within the context of the broader electricity market, which includes an assessment of incremental plant closures attributable to this rule.

The following sections summarize the findings for these analyses. The RIA discusses the methods and results in greater detail.

1. Summary of Economic Impacts for Existing Sources

The first set of cost and economic impact analyses—including entity-level impacts at both the steam electric power plant and parent company levels—reflects baseline operating characteristics of steam electric power plants incurring costs and assumes no changes in those baseline operating characteristics (*e.g.,* level of electricity generation and revenue) as a result of the final rule. They provide screening-level indicators of the relative cost of the ELGs to plants, owning entities, or consumers.

The second set of analyses look at broader electricity market impacts taking into account the interconnection of regional and national electricity markets. It also looks at the distribution of impacts at the plant level. This second set of analyses provides insight on the impacts of the final rule on steam electric power plants, as well as the electricity market as a whole, including generation capacity closure and changes in generation and wholesale electricity prices.

As noted in the introduction to this section, EPA used results from the screening analysis of plant- and entity-level impacts, together with projected capacity closure from the market model, to determine that the final rule is economically achievable.

a. Screening-Level Assessment of Impacts on Existing Units at Steam Electric Power Plants and Parent Entities

EPA conducted a screening-level analysis of the rule's potential impact to existing generating units at steam electric power plants and parent entities based on cost-to-revenue ratios. For each of the two levels of analysis (plant and parent entity), the Agency assumed, for analytic convenience and as a worst-case scenario, that none of the costs would be passed on to consumers through electricity rate increases and would instead be absorbed by the steam electric power plants and their parent entities. This assumption overstates the impacts of the final rule since steam electric power plants that operate in a regulated market may be able to recover some of the increased production costs to consumers through increased electricity prices. It is, however, an appropriate assumption for a screening-level, upper-bound estimate of the potential cost impacts.

Plant-Level Cost-to-Revenue Analysis. EPA developed revenue estimates for this analysis using EIA data. EPA then calculated the annualized after-tax costs of the final rule as a percent of baseline annual revenues. See Chapter 4 of the RIA report for a more detailed discussion of the methodology used for the plant-level cost-to-revenue analysis.

Table IX–3 summarizes the plant-level cost-to-revenue analysis results for the final rule. The cost-to-revenue ratios provide screening-level indicators of potential economic impacts. Plants incurring costs below one percent of revenue are unlikely to face economic impacts, while plants with costs between one percent and three percent of revenue have a higher chance of facing economic impacts, and plants incurring costs above three percent of revenue have a still higher probability of economic impacts. EPA estimates that the vast majority of steam electric power plants (1,034 plants or 96 percent of the universe) to which the final rule apply will incur annualized costs amounting to less than one percent of revenue. In fact, most of these plants will incur no cost at all. Only four percent of plants have costs between one percent and three percent of revenue (38 plants), and less than one percent of plants have costs above three percent of revenue (8 plants). The small fractions of steam electric power plants with costs to revenue ratios exceeding the one percent and three percent thresholds suggest that the final limitations and standards are economically achievable for the industry as a whole.

TABLE IX–3—PLANT-LEVEL COST-TO-REVENUE ANALYSIS RESULTS [a]

	Number and fraction of existing steam electric power plants with cost-to-revenue ratio of							
	0%		0–1%		1–3%		>3%	
	#	%	#	%	#	%	#	%
Count or Percent of Plants	946	88	88	8	38	4	8	1

[a] This analysis makes a counterfactual, conservative assumption of zero cost pass through. Plant counts are weighted estimates.

Parent Entity-Level Cost-to-Revenue Analysis. EPA also assessed the economic impact of the final rule at the parent entity level. The screening-level cost-to-revenue analysis at the parent entity level provides insight on the impact of the final rule on those entities that own existing generating units at steam electric power plants. In this analysis, the domestic parent entity associated with any given plant is defined as that entity with the largest ownership share in the plant.

For each parent entity, EPA compared the total annualized after-tax costs and the total revenue for the entity (see Chapter 4 of the RIA report for details). EPA considered two approximate bounding cases to analyze costs and revenue for the owners of all existing units at steam electric power plants, based on the weights developed from the industry survey. These cases, which are described in more detail in Chapter 4 of the RIA, provide a range of estimates for the number of entities incurring costs and the costs incurred by any entity owning an existing generating unit at a steam electric power plant.

Table IX–4 summarizes the results of the entity-level analysis of the final rule for the two analytic cases.

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

Total number of entities	Not analyzed due to lack of revenue information		Number and percentage with after tax annual costs/annual revenue of:							
			0%		0–1%		1–3%		3% or greater	
	#	%	#	%	#	%	#	%	#	%
Case 1: Lower-bound estimate of number of entities owning steam electric power plants (which also provides an upper-bound estimate of total costs that an entity may incur)										
243	14	6	166	68	53	22	8	3	2	1
Case 2: Upper-bound estimate of number of entities owning steam electric power plants (which also provides a lower-bound estimate of total costs that an entity may incur)										
507	30	6	414	82	53	10	8	2	2	<1

equals the number of entities.

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

Similar to the plant-level analysis above, cost-to-revenue ratios provide screening-level indicators of potential economic impacts, this time to the owning entities; higher ratios suggest a higher probability of economic impacts. As presented in Table IX–4, EPA estimated that the number of entities owning existing generating units at steam electric power plants ranges from 243 (lower-bound estimate) to 507 (upper-bound estimate), depending on the assumed ownership structure of plants not surveyed. EPA estimates that 90 percent to 92 percent of parent entities will either incur no costs or the annualized cost they incur to meet the final limitations and standards will represent less than one percent of their revenues, under the lower- and upper-bound cases, respectively.

Overall, this screening-level analysis shows that the entity-level costs are low in comparison to the entity-level revenues; very few entities are likely to face economic impacts at any level. This finding supports EPA's determination that the final rule is economically achievable by the steam electric power generation industry as a whole.

b. Assessment of Impacts in the Context of the Electricity Market

In analyzing the impacts of regulatory actions affecting the electric power sector, EPA has used IPM, a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. The model is designed to evaluate the effects of changes in generating unit-level electric generation costs on the total cost of electricity supply, subject to specified demand and emissions constraints.

Use of a comprehensive, market analysis system is important in assessing the potential impact of the regulation because of the interdependence of electric generating units in supplying power to the electric transmission grid. Increases in electricity production costs at some generating units can have a range of broader market impacts affecting other generating units, including the likelihood that various units are dispatched, on average. The analysis also provides important insight on steam electric capacity closures (*e.g.,* retirements of generating units that become uneconomical relative to other generating units), based on a more detailed analysis of market factors than in the screening-level analyses above, and it further informs EPA's determination of whether the final ELGs are economically achievable by the industry as a whole.

EPA used version 5.13 of IPM to analyze the impacts of the final rule. IPM V5.13 is based on an inventory of U.S. utility- and non-utility-owned boilers and generators that provide power to the integrated electric transmission grid, including plants to which the ELGs apply. IPM V5.13 embeds a baseline energy demand forecast that is derived from DOE's ''Annual Energy Outlook 2013'' (AEO 2013). IPM V5.13 also incorporates in its analytic baseline the expected compliance response to existing regulatory requirements for air regulations affecting the power sector.[42] In addition, the Base Case for IPM analyses of the final ELGs accounts for the effects of the final CWIS rule and CCR rule, as well as the CPP rule.[43] As explained in Section V, because of the short time between finalizing the CPP rule and this final rule, EPA's IPM analysis for this final rule incorporates the proposed CPP rule in the baseline. EPA concludes the proposed and final CPP specifications are similar enough that using the proposed rather than the final CPP will not bias the results of the

[42] The Base Case includes the following regulations: Clean Air Interstate Rule (CAIR); Mercury and Air Toxics Standards (MATS) rule; regulatory SO_2 emission rates arising from State Implementation Plans (SIP); Acid Rain Program established under Title IV of the Clean Air Act Amendments; NO_X SIP Call trading program for Rhode Island; Clean Air Act Reasonable Available Control Technology requirements and Title IV unit specific rate limits for NO_X; the Regional Greenhouse Gas Initiative; Renewable Portfolio Standards; New Source Review Settlements; and several state-level regulations affecting emissions of SO_2, NO_X, and mercury that are already in place or expected to come into force by 2017.

[43] EPA typically includes only final rules in its base case for its IPM analyses. However, at the time EPA performed the IPM analyses for this rule, it did not have details of the final CPP rule. EPA therefore used information from the proposed CPP rule as a proxy for purposes of the ELG analyses.

analysis for this rule. This conclusion is based on a careful evaluation of whether the population of steam electricity generating units that would incur costs under the ELGs in the final CPP differs meaningfully from the proposed CPP baseline. The analyses led us to conclude that using the proposed CPP baseline in lieu of the final CPP baseline is acceptable because (1) the number of steam electric generating units that would incur costs under the ELGs is very similar on either baseline, and (2) where the populations differ, the net number of steam electric generating units that are in one baseline and not the other is small relative to the total population of steam electric generating units that would incur costs under the ELGs in either baseline. See the RIA for additional details.

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

In analyzing the final ELGs, EPA specified additional fixed and variable costs that are expected to be incurred by specific steam electric power plants and generating units to comply with the ELGs (the costs discussed in Section IX.A). EPA then ran IPM including these additional costs to determine the dispatch of electric generating units that would meet projected demand at the lowest costs, subject to the same constraints as those present in the analysis baseline. The estimated changes in plant-specific and unit-specific production levels and costs—and, in turn, changes in total electric power sector costs and production profile—are key data elements in evaluating the expected national and regional effects of the ELGs, including closures of steam electric generating units.

EPA considered impact metrics of interest at three levels of aggregation: (1) Impact on national and regional electricity markets (all electric power generation, including steam and non-steam electric power plants), (2) impact on steam electric power plants as a group, and (3) impact on individual steam electric power plants incurring costs. Chapter 5 of the RIA discusses the first analysis. The sections below summarize the two analyses focusing on steam electric power plants, which are further described in Chapter 5 of the RIA.

All results presented below are representative of modeled market conditions in the years 2028–2033, by which time all plants will meet the effluent limitations and standards. Costs are reflective of costs in the modeled years.[44]

Impact on Existing Steam Electric Power Plants. EPA used IPM V5.13 results for 2030 to assess the potential impact of the final rule on existing generating units at steam electric power plants. The purpose of this analysis is to assess impacts on existing generating units at steam electric power plants specifically. EPA used this information in determining whether the ELGs are economically achievable by the steam electric power generating industry as a whole.

Table IX–5 reports results for existing generating units at steam electric power plants, as a group. EPA looked at the following metrics: (1) Incremental early retirements and capacity closures, calculated as the difference between capacity under the ELGs and capacity under the baseline, which includes both full plant closures and partial plant closures (unit closures) in aggregate capacity terms; (2) incremental capacity closures as a percentage of baseline capacity; (3) post-compliance change in electricity generation; (4) post-compliance changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; and (5) changes in annual costs (fuel, variable O&M, fixed O&M, and capital). Items (1) and (2) provide important insight for determining the economic achievability of the ELGs.

TABLE IX–5—IMPACT OF FINAL ELGS ON STEAM ELECTRIC POWER PLANTS AS A GROUP AT THE YEAR 2030

Region	Baseline capacity (MW)	Incremental early retirements closures[a]		Change in total generation (GWh or % of baseline)		Change in variable production cost (2013$/MWh or % of baseline)		Change in annual costs (million 2013$ or % of baseline)	
		Capacity (MW)	% of baseline capacity						
Total U.S.	359,982	843	0.2%	−3,179	−0.2%	$0.10	0.3%	$496	0.6%

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

Under the final rule, variable production costs at steam electric power plants increase by approximately 0.3 percent at the national level. The resulting net change in total capacity for steam electric power plants is very small. For the group of steam electric power plants, total capacity decreases by 843 MW or approximately 0.2 percent of the 359,982 MW baseline capacity, corresponding to a net closure of two units, or when aggregating to the level of steam electric generating plants, one net plant closure.

The change in total generation is an indicator of how steam electric power plants fare, relative to the rest of the electricity market. While at the market level there is essentially no projected change in total electricity generation,[45]

[44] In contrast, the social costs estimated in Section IX.B reflect the discounted value of compliance costs over the entire 24-year period of analysis, as of 2015.

[45] As discussed in the RIA, at the national level, the demand for electricity does not change between

Continued

for steam electric power plants, total available capacity and electricity generation at the national level are projected to fall by approximately 0.2 percent.

These findings of very small national effects (and similarly very small regional effects, as described in Chapter 5 of the RIA) in these impact metrics support EPA's conclusion that the final rule will have little economic consequence for the steam electric power generating industry and the electricity market and is, therefore, economically achievable.

Impact on Individual Steam Electric Power Plants Incurring Costs under this Rulemaking. To assess potential plant-level effects, EPA also analyzed plant-specific changes between the base case and the post-compliance cases for the following metrics: (1) Capacity utilization (defined as annual generation (in MWh) divided by [capacity (MW) times 8,760 hours]) (2) electricity generation, and (3) variable production costs per MWh, defined as variable O&M cost plus fuel cost divided by net generation.

The analysis of changes in individual plants as a result of the final rule is detailed in Chapter 5 of the RIA. The results indicate that steam electric plants experience only slight effects—no change, or less than a one percent reduction or one percent increase. See Table 5–4 in the RIA. Only 17 plants see their capacity utilization reduced by more than one percent, while 25 plants increase their capacity utilization by more than one percent. The estimated change in variable production costs is higher; 43 plants have an increase in variable production costs exceeding one percent; for seven of these plants, this increase exceeds three percent, but again the vast majority of plants experience a less than one percent increase in variable production costs. Results for the subset of plants incurring costs further support the conclusion that the effects of the final rule on the steam electric industry will be small.

2. Summary of Economic Impacts for New Sources

EPA also evaluated the expected costs of meeting the final standards for new sources. The incremental cost associated with complying with the final NSPS and PSNS varies depending on the types of processes, wastestreams, and waste management systems that the plant would have installed in the absence of the new source requirements. EPA estimated capital and O&M costs for several scenarios that represent the different types of operations present at existing steam electric power plants or typically included at new steam electric power plants. These scenarios capture differences in the plant status (building a generating unit at a new location versus adding a new generating unit at an existing power plant), presence of on-site impoundments or landfills, type of ash handling, type of FGD systems in service, and type of leachate collection and handling.

EPA assessed the possible impact of this final rule on new units by comparing the incremental costs for new units to the overall cost of building and operating new scrubbed coal units, on an annualized basis.

EPA estimated costs of a new coal unit using the overnight [46] capital and O&M costs of building and operating a new scrubbed coal unit from the EIA's Annual Energy Outlook 2014. For purposes of this analysis, EPA assumed a new dual-unit plant with a total generation capacity of 1,300 MW. Table IX–6 shows capital and O&M costs of building and operating a new coal unit and contrasts these costs with the incremental costs associated with the final NSPS/PSNS.

TABLE IX–6—COMPARISON OF INCREMENTAL COMPLIANCE COSTS WITH COSTS FOR NEW COAL-FIRED STEAM ELECTRIC UNITS

Cost component	Costs of new coal generation ($2013/MW) [a]	Incremental compliance costs ($2013/MW) [b]	% of new generation cost
Capital	$3,058,861	$8,328–$87,085	0.3–2.8
Annual Non-Fuel O&M	69,630	620–8,828	0.3–3.9
Annual Fuel [c]	157,737		
Total Annualized Costs	497,213	1,354–16,511	0.3–3.3

[a] Source: New unit total cost value from Table 8.2 EIA NEMS Electricity Market Module. AEO 2014 Documentation. Available at *http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf.* Capital costs are based on the total overnight costs for new scrubbed coal dual-unit plant, 1,300 MW capacity, coming online in 2017. EPA restated costs in 2013 dollars using the construction cost index. Total annual O&M costs assume 90% capacity utilization.

[b] Incremental costs for new 1300 MW unit for Option F. Range represents the costs for a new unit at a newly constructed plant (lower bound) and new unit at an existing plant, with evaporation technology (upper bound).

[c] Fuel costs estimated assuming heat rate of 8,800 Btu/kWh (AEO 2014) and coal price delivered to the power sector of 2.27 $/Mbtu (AEO 2015, projected costs in 2017 in 2013$).

The comparison suggests that costs associated with meeting the final NSPS/PSNS represent a relatively small fraction of overnight capital costs of a new unit (less than one percent) and a similarly small fraction of non-fuel O&M and fuel costs (less than one percent). On an annualized basis, costs for meeting standards specified in the final rule are 0.3 to 3.3 percent of annualized costs for new coal generating capacity. Based on this assessment, EPA concludes that the final rule does not present a barrier to entry.

X. Pollutant Reductions

EPA took a similar approach to the one described above for plant-specific costs in estimating pollutant reductions associated with the final rule. For each wastestream [47] and each POC, EPA first estimated—on an annual, per plant basis—plant-specific baseline pollutant

the baseline and the analyzed regulatory options (generation within the regions is allowed to vary) because meeting demand is an exogenous constraint imposed by the model.

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

[47] EPA estimated pollutant reductions for wastestreams with numeric and zero pollutant discharge limitations and standards. The reductions reflect a reduction in the mass of pollutant discharged.

loadings taking into account components in place at the plant (or expected to be in place given other existing rules [48]) and, where appropriate, pollutant removals at the POTW, since these removals result in reduced discharges to receiving waters. EPA similarly estimated plant-specific post-compliance pollutant loadings using the mean concentrations associated with the final limitations and standards. In cases where a plant had already implemented approaches that would allow them to comply with the final rule, the baseline and post-compliance pollutant loadings are equivalent. EPA then calculated the pollutant reduction as the difference between the estimated baseline and post-compliance discharge loadings. For each wastestream, EPA then calculated total industry pollutant reductions by applying survey weights to the plant-specific pollutant reductions and summing them.

While plants are not required to implement the specific technologies that form the bases for the final limitations and standards, EPA calculated the pollutant loadings for plants that implement these technologies to estimate the pollutant reductions associated with the rule. See TDD Section 10 for a detailed discussion of EPA's pollutant loadings and reductions methodologies.

Table X–1 presents estimated industry-level pollutant reductions for the final rule.

TABLE X–1—TOTAL ANNUALIZED POLLUTANT LOADING REDUCTIONS

Analysis baseline	Pollutant reductions (pounds per year)		
	Conventional pollutants [a]	Priority pollutants	Nonconventional pollutants [b]
Final Rule	13,400,000	410,000	371,000,000

[a] The loadings reduction for conventional pollutants includes BOD and TSS.

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

XI. Development of Effluent Limitations and Standards

The final rule establishes a zero discharge limitation and standard applicable to all pollutants in fly ash transport water, bottom ash transport water, and FGMC wastewater; therefore, no effluent concentration data were used to set the limitations and standards for these wastestreams. The final rule contains new numeric effluent limitations and standards that apply to discharges of FGD wastewater and gasification wastewater at new and existing sources, and to discharges of combustion residual leachate at new sources.[49]

EPA developed the new numeric effluent limitations and standards in this final rule using long-term average effluent values and variability factors that account for variation in performance at well-operated facilities that employ the technologies that constitute the bases for control. EPA's methodology for derivation of limitations in ELGs is longstanding and has been upheld in court. *See, e.g., Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d 177 (5th Cir. 1989); *Nat'l Wildlife Fed'n* v. *EPA,* 286 F.3d 554 (D.C. Cir. 2002). EPA establishes the final effluent limitations and standards as ''daily maximums'' and ''maximums for monthly averages.'' Definitions provided in 40 CFR 122.2 state that the daily maximum limitation is the ''highest allowable 'daily discharge' '' and the maximum for monthly average limitation is the ''highest allowable average of 'daily discharges' over a calendar month, calculated as the sum of all 'daily discharges' measured during a calendar month divided by the number of 'daily discharges' measured during that month.'' Daily discharges are defined to be the '' 'discharge of a pollutant' measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling.''

EPA's objective in establishing daily maximum limitations is to restrict the discharges on a daily basis at a level that is achievable for a plant that targets its treatment at the long-term average. EPA acknowledges that variability around the long-term average occurs during normal operations. This variability means that plants occasionally may discharge at a level that is higher (or lower) than the long-term average. To allow for these possibly higher daily discharges and provide an upper bound for the allowable concentration of pollutants that may be discharged, while still targeting achievement of the long-term average, EPA has established the daily maximum limitation. A plant that consistently discharges at a level near the daily maximum limitation would *not* be operating its treatment to achieve the long-term average. Targeting treatment to achieve the daily limitation, rather than the long-term average, may result in values that frequently exceed the limitations due to routine variability in treated effluent.

EPA's objective in establishing monthly average limitations is to provide an additional restriction to help ensure that plants target their average discharges to achieve the long-term average. The monthly average limitation requires dischargers to provide ongoing control, on a monthly basis, that supplements controls imposed by the daily maximum limitation. In order to meet the monthly average limitation, a plant must counterbalance a value near the daily maximum limitation with one or more values well below the daily maximum limitation.

The TDD provides a detailed description of the data and methodology used to develop long-term averages, variability factors, and limitations and standards for the final rule. As a result of public comments, EPA expanded the data set used to calculate the BAT/PSES effluent limitations and standards for discharges of FGD wastewater from existing sources. Largely, this expanded data set includes additional self-monitoring data from plants operating

[48] As explained elsewhere in this preamble, for this final rule, EPA adjusted its estimates to, among other things, account for known generating unit closures and conversions and known operating changes, including those associated with the CCR rule, expected to occur prior to the time in which the limitations and standards in this rule would apply. As such, baseline loadings in this final rule reflect closures, conversions, and operational changes that will take place prior to implementation of the rule in NPDES permits, rather than the industry survey baseline year of 2009 used in the proposed rule.

[49] Effluent limitations and standards based on the previously established BPT limitations on TSS are not discussed in this section.

the selected technology basis. EPA also expanded the data set by including treatment performance data from another plant that, upon review of comments, EPA determined would be appropriate to use to calculate the effluent limitations in this rule. The combination of EPA sampling data (both EPA-collected and CWA section 308 samples collected by plants for analysis by EPA) and plant self-monitoring data results in data sets characterizing the treatment system performance over several years at each of the plants used to develop effluent limitations and standards for FGD wastewater.

EPA identified certain data that warranted exclusion from the calculations of the limitations and standards because: (1) The samples were analyzed using an analytical method that is not approved in 40 CFR part 136 for NPDES permit purposes; (2) the samples were analyzed using an insufficiently sensitive analytical method (*e.g.,* use of EPA Method 245.1 to measure the concentration of mercury in effluent samples); (3) the samples were analyzed in a manner which resulted in an unacceptable level of analytical interferences; (4) the samples were collected during the initial commissioning period for the wastewater treatment system or the plant decommissioning period and do not represent BAT/NSPS level of performance; (5) the analytical results were identified as questionable due to quality control issues, abnormal conditions or treatment system upsets, or were analytical anomalies; (6) the samples were collected from a location that is not representative of treated effluent; or (7) the treatment system was operating in a manner that does not represent BAT/NSPS level of performance. The results of EPA's evaluation of the data and reasons for any data exclusions are summarized in DCN SE05733.

Tables XI–1 and XI–2 present the effluent limitations and standards for FGD wastewater, gasification wastewater, and combustion residual leachate. For comparison, the tables also present the long-term average treatment performance calculated for these wastestreams. Due to routine variability in treated effluent, a power plant that targets discharging its wastewater at a level near the values of the daily maximum limitation or the monthly average limitation may experience frequent values exceeding the limitations. For this reason, EPA recommends that plants design and operate the treatment system to achieve the long-term average for the model technology. In doing so, a system that is designed to represent the BAT/NSPS level of control would be expected to meet the limitations.

EPA expects that plants will be able to meet their effluent limitations or standards at all times. If an exceedance is caused by an upset condition, the plant would have an affirmative defense to an enforcement action if the requirements of 40 CFR 122.41(n) are met. Exceedances caused by a design or operational deficiency, however, are indications that the plant's performance does not represent the appropriate level of control. For these final limitations and standards, EPA determined that such exceedances can be controlled by diligent process and wastewater treatment system operational practices, such as regular monitoring of influent and effluent wastewater characteristics and adjusting dosage rates for chemical additives to target effluent performance for regulated pollutants at the long-term average concentration for the BAT/NSPS technology. Additionally, some plants may need to upgrade or replace existing treatment systems to ensure that the treatment system is designed to achieve performance that targets the effluent concentrations at the long-term average. This is consistent with EPA's costing approach and its engineering judgment developed over years of evaluating wastewater treatment processes for steam electric power plants and other industrial sectors. EPA recognizes that, as a result of the final rule, some dischargers, including those that are operating technologies representing the technology bases for the final rule, may need to improve their treatment systems, process controls, and/or treatment system operations in order to consistently meet the effluent limitations and standards. This is consistent with the CWA, which requires that discharge limitations and standards reflect the best available technology economically achievable or the best available demonstrated control technology.

See DCN SE05733 for details of the calculation of the limitations and standards presented in the tables below.

TABLE XI–1—LONG-TERM AVERAGES AND EFFLUENT LIMITATIONS AND STANDARDS FOR FGD WASTEWATER AND GASIFICATION WASTEWATER FOR EXISTING SOURCES

Wastestream	Pollutant	Long-term average	Daily maximum limitation	Monthly average limitation
FGD Wastewater (BAT & PSES)	Arsenic (µg/L)	5.98	11	8
	Mercury (ng/L)	159	788	356
	Nitrate/nitrite as N (mg/L)	1.3	17.0	4.4
	Selenium (µg/L)	7.5	23	12
Voluntary Incentives Program for FGD Wastewater (BAT only).	Arsenic (µg/L)	[a] 4.0	[b] 4	([c])
	Mercury (ng/L)	17.8	39	24
	Selenium (µg/L)	[a] 5.0	[b] 5	([c])
	TDS (mg/L)	14.9	50	24
Gasification Wastewater (BAT & PSES)	Arsenic (µg/L)	[a] 4.0	[b] 4	([c])
	Mercury (ng/L)	1.08	1.8	1.3
	Selenium (µg/L)	147	453	227
	TDS (mg/L)	15.2	38	22

[a] Long-term average is the arithmetic mean of the quantitation limits since all observations were not detected.
[b] Limitation is set equal to the quantitation limit.
[c] Monthly average limitation is not established when the daily maximum limitation is based on the quantitation limit.

TABLE XI–2—LONG-TERM AVERAGES AND STANDARDS FOR FGD WASTEWATER, GASIFICATION WASTEWATER, AND COMBUSTION RESIDUAL LEACHATE FOR NEW SOURCES

Wastestream	Pollutant	Long-term average	Daily maximum limitation	Monthly average limitation
FGD Wastewater (NSPS & PSNS)	Arsenic (µg/L)	[a] 4.0	[b] 4	([c])
	Mercury (ng/L)	17.8	39	24
	Selenium (µg/L)	[a] 5.0	[b] 5	([c])
	TDS (mg/L)	14.9	50	24
Gasification Wastewater (NSPS & PSNS)	Arsenic (µg/L)	[a] 4.0	[b] 4	([c])
	Mercury (ng/L)	1.08	1.8	1.3
	Selenium (µg/L)	147	453	227
	TDS (mg/L)	15.2	38	22
Combustion Residual Leachate (NSPS & PSNS)	Arsenic (µg/L) [d]	5.98	11	8
	Mercury (ng/L) [d]	159	788	356

[a] Long-term average is the arithmetic mean of the quantitation limits since all observations were not detected.
[b] Limitation is set equal to the quantitation limit.
[c] Monthly average limitation is not established when the daily maximum limitation is based on the quantitation limit.
[d] Long-term average and standards were transferred from performance of chemical precipitation in treating FGD wastewater.

XII. Non-Water Quality Environmental Impacts

The elimination or reduction of one form of pollution can create or aggravate other environmental problems. Therefore, CWA sections 304(b) and 306 require EPA to consider non-water quality environmental impacts (including energy requirements) associated with ELGs. Accordingly, EPA considered the potential impact of this rule on energy consumption, air emissions, and solid waste generation.[50] In addition, EPA evaluated the effects associated with water withdrawal. For information on the methodologies EPA used to estimate the non-water quality environmental impacts, see TDD Section 12.

Table XII–1 presents the net increases in energy requirements for the final rule. EPA estimates that energy increases associated with this rule are less than 0.01 percent of the total electricity generated by all electric power plants and the fuel consumption increase is 0.002 percent of total fuel consumption by all motor vehicles in the U.S.

TABLE XII–1—INDUSTRY-LEVEL ENERGY REQUIREMENTS FOR THE FINAL RULE

Non-water quality environmental impact	Final rule
Electrical Energy Usage (MWh)	237,000
Fuel (GPY)	556,000

Table XII–2 presents the estimated net change in air emissions for the final rule. Table XII–2 shows that the estimated air emission increases are less than 0.04 percent of the total air emissions generated in 2009 by the electric power industry for the three pollutants evaluated.

TABLE XII–2—AIR EMISSIONS ASSOCIATED WITH BAT/PSES FOR FINAL RULE

Non-water quality environmental impact	2009 emissions by electric power industry (million tons)	Change in air emissions associated with final rule (million tons)	Increase in emissions for final rule (%)
NO_X	1	−0.0114	−1.16
SO_X	6	0.00243	0.0406
CO_2	2,403	−2.58	−0.107

EPA compared the estimated increase in solid waste generation to the amount of solids generated in a year by electric power plants throughout the U.S.—approximately 134 billion tons. The increase in solid waste generation associated with the final rule is less than 0.001 percent of the total solid waste generated by all electric power plants.

EPA estimates that, under the final rule, steam electric power plants will reduce their water withdrawal by 57 billion gallons per year (155 million gallons per day). See TDD Section 12.

Based on these analyses, EPA determined that the final BAT effluent limitations and PSES have acceptable non-water quality environmental impacts, including energy impacts.

XIII. Environmental Assessment

A. Introduction

Although not required to do so, EPA conducted an environmental assessment for the final rule, as it did for the proposed rule. The environmental assessment for the final rule reviewed currently available literature on the documented environmental and human health impacts of steam electric power plant wastewater discharges and

[50] Because EPA does not project any new coal or oil-fired generating units, the results presented in this section reflect existing generating units. Because EPA expects non-water quality environmental impacts for new generating units to be similar to or the same as existing generating units, EPA determined that in the event a new generating unit is built, the non-water quality environmental impacts associated with NSPS/PSNS would be acceptable. For EPA's analysis of non-water quality impacts for existing generating units for Option F, see Section 12 of the TDD.

conducted modeling to determine the cumulative impacts of pollution from the universe of steam electric power plants to which the final rule applies. EPA modeled both the impacts of steam electric power plant discharges at baseline conditions (pre-rule conditions) and the improvements that will likely result after implementation of the rule.

EPA's review of the scientific literature; documented cases of the extensive impacts of steam electric power plant wastewater discharges on human health and the environment; and a full description of EPA's modeling methodology and results are provided in the EA.

B. Summary of Human Health and Environmental Impacts

As discussed in the environmental assessment and proposed rule, current scientific literature indicates that steam electric power plant wastewaters such as fly ash transport water, bottom ash transport water, FGD wastewater, and combustion residual leachate contain large amounts of a wide range of harmful pollutants, some of which are toxic and bioaccumulative, and which cause significant, widespread detrimental environmental and human health impacts.

Discharges of steam electric power plant wastewaters present a serious public health concern due to the potential human exposure to toxic pollutants through consumption of contaminated fish and drinking water. Toxic pollutants that detrimentally affect human health that are commonly found in steam electric power plant wastewater discharges include mercury, lead, arsenic, cadmium, thallium, and selenium, along with numerous others (see EA Section 3). These pollutants are associated with a variety of documented adverse human health impacts. For example, human exposure to elevated levels of mercury for relatively short periods of time can result in kidney and brain damage. Pregnant women who are exposed to mercury can pass the contaminant to their developing fetus, leading to possible toxic injury of the fetal brain and damage to other parts of the nervous system. Human exposure to elevated levels of lead can cause serious damage to the brain, kidneys, nervous system, and red blood cells, especially in children. Arsenic is associated with an increased risk of liver and bladder cancer in humans, as well as non-cancer impacts including dermal, cardiovascular, respiratory, and reproductive effects such as excess incidences of miscarriages, stillbirths, preterm births, and low birth weights. Chronic exposure to cadmium, a probable carcinogen, can lead to kidney failure, lung damage, and weakened bones. Human exposure to elevated levels of thallium can lead to neurological symptoms, hair loss, gastrointestinal effects, liver and kidney damage, and reproductive and developmental damage. Long-term exposure to selenium can damage the kidney, liver, and nervous and circulatory systems.

The pollutants in steam electric power plant wastewater can bioaccumulate within fish and other aquatic wildlife in the receiving waters and subsequently be transferred to recreational and subsistence fishers who consume these contaminated fish, potentially resulting in the acute and chronic health impacts described above. Certain populations are particularly at risk, including women who are pregnant, nursing, or may become pregnant, and communities relying on consumption of fish from contaminated waters as a major food source.

Discharges of steam electric power plant pollutants to surface waters also have the potential to contaminate drinking water sources, causing potential problems for drinking water systems and, if left untreated, potential adverse health effects. A recent study indicates that pollutants in ash and FGD wastewater discharges exceeded MCLs in every surface water that was monitored in North Carolina during the study (see DCN SE01984). Nitrogen discharges from steam electric power plants can contribute, along with other sources, to harmful algal blooms. Harmful algal blooms can affect drinking water sources, such as the recent incident in Toledo, Ohio (see DCN SE04517).

Bromide discharges from steam electric power plants can contribute to the formation of carcinogenic DBPs in public drinking water systems. A recent study identified four drinking water treatment plants that experienced increased levels of bromide in their source water, and in some, a corresponding increase in the formation of brominated DBPs in the drinking water system, after the installation of wet FGD scrubbers at upstream steam electric power plants (see DCN SE04503).

Although not directly addressed by this final rule, ground water contamination from surface impoundments containing steam electric power plant wastewater also threatens drinking water sources. EPA identified more than 30 documented cases where ground water contamination from surface impoundments extended beyond the plant boundaries, illustrating the threat to ground water drinking water sources (see DCN SE04518). Where this final rule helps to reduce or eliminate the continued disposal or storage of steam electric power plant wastewater pollutants in unlined or leaking surface impoundments, potential impacts to ground water will also be reduced or eliminated.

The ecological impacts of steam electric power plant wastewater pollutants include both acute (*e.g.,* fish kills) and chronic effects (*e.g.,* reproductive failure, malformations, and metabolic, hormonal, and behavioral disorders) upon biota within the receiving water and the surrounding environment. Recovery of aquatic environments from exposure to these steam electric power plant pollutants can be extremely slow due to the accumulation and continued cycling of the pollutants within ecosystems, resulting in the potential to alter ecological processes such as population diversity and community dynamics. Furthermore, many steam electric power plants discharge pollutants to sensitive environments such as the Great Lakes, valuable estuaries such as the Chesapeake Bay, 303(d) listed impaired waters, and waters with fish consumption advisories. EPA identified 69 steam electric power plants with documented adverse environmental impacts on surface waters (see DCN SE04518).

C. Environmental Assessment Methodology

As discussed in Section V.G, EPA updated the environmental assessment for the final rule to respond to public comments and to better characterize the environmental and human health improvements associated with the final rule. Although not required to do so, EPA conducted an environmental assessment for the final rule. The environmental assessment reviewed currently available literature on the documented environmental and human health impacts of steam electric power plant wastewater discharges and conducted modeling to determine the cumulative impacts of pollution from the universe of steam electric power plants to which the final rule applies. EPA modeled both of the impacts of steam electric power plant discharges at baseline conditions and the improvements that will likely result after implementation of this rule. The final environmental assessment also incorporates changes to the industry profile to account for retirements, conversions, and operational changes that EPA anticipates, given other existing rules, primarily the CCR and CPP rules.

The environmental assessment modeling for the final rule consisted of (1) a steady-state, national-scale immediate receiving water (IRW) model that evaluated the discharges from steam electric power plants and focused on impacts within the immediate surface water where the discharges occur (approximately one to 10 kilometers [km] from the outfall),[51] and (2) dynamic case study models with more extensive, site-specific modeling of selected waterbodies that receive, or are downstream from, steam electric power plant discharges. EPA also modeled receiving water concentrations downstream from steam electric power plant discharges using EPA's Risk-Screening Environmental Indicators (RSEI) model, and improved its modeling of selenium bioaccumulation in fish and wildlife.

Additionally, for the final rule, EPA updated and improved several input parameters for the IRW model, including fish consumption rates for recreational and subsistence fishers, the bioconcentration factor for copper, and benchmarks for assessing the potential for impacts to benthic communities in receiving waters.

The case-study modeling for the final rule is based on EPA's Water Quality Analysis Simulation Program (WASP), which accounts for fluctuations in receiving water flow rates by using daily stream flow monitoring data instead of one annual average flow rate for the receiving water, as used in the IRW. The case-study modeling accounts for pollutant transport and accumulation within receiving water reaches that are downstream from the discharge location, allowing for an assessment of environmental impacts over a larger portion of the receiving waterbody. The case study modeling also accounts for pollutant contributions from other point, nonpoint, and background sources, to the extent practical, using available data sources. EPA used the water quality results of the case-study modeling to supplement the results of the IRW model (see EA Section 8).

EPA improved its selenium bioaccumulation modeling for impacts on wildlife by developing and using an ecological risk model that predicts the risk of reproductive impacts among fish and waterfowl exposed to selenium from steam electric power plant wastewater discharges. The ecological risk model accounts for the bioaccumulation of selenium in aquatic organisms through dietary exposure (the food web), as contrasted with exposure only to dissolved selenium in the water column. Dietary exposure plays a more significant role in determining the extent of selenium bioaccumulation in aquatic organisms. The ecological risk model also accounts for the higher rates of selenium bioaccumulation that can occur in slow-flowing aquatic systems such as lakes and reservoirs, and the risk model translates selenium tissue concentrations into the predicted risk of adverse reproductive effects (*e.g.,* reduced egg hatchability, larval mortality, and deformities that affect survival) among exposed fish and waterfowl. EPA applied the ecological risk model to the water quality outputs from both the national-scale IRW model and the case-study models. See EA Section 5.2 for a more detailed discussion.

[51] The IRW model used for the final rule is substantially similar to the one used for the proposed rule, but with certain updates, as further discussed in this section.

D. Outputs From the Environmental Assessment

EPA focused its quantitative analyses on the environmental and human health impacts associated with exposure to toxic bioaccumulative pollutants via the surface water pathway. EPA focused the modeling on discharges of toxic bioaccumulative pollutants from a subset of evaluated wastestreams from steam electric power plants (fly ash and bottom ash transport water, FGD wastewater, and combustion residual leachate) into rivers/streams and lakes/ponds (including reservoirs).[52] EPA addressed environmental impacts from nutrients in a separate analysis discussed in Section XIII.D.5.

The environmental assessment concentrates on impacts to aquatic life based on changes in surface water quality; impacts to aquatic life based on changes in sediment quality within surface waters; impacts to wildlife from consumption of contaminated aquatic organisms; and impacts to human health from consumption of contaminated fish and water. Table XIII–1 presents a list of the key environmental improvements projected within the immediate receiving waters due to the pollutant loading reductions under the final rule. These improvements are discussed in detail, with quantified results, in the EA.

[52] EPA did not use the state 303d lists of impaired waters in order to ensure comprehensive coverage of all pollutants of concern.

TABLE XIII–1—KEY ENVIRONMENTAL IMPROVEMENTS WITHIN MODELED IMMEDIATE RECEIVING WATERS UNDER THE FINAL RULE [53]

Criteria evaluated for exceedances	Will improve under the final rule?
Freshwater Acute National Recommended WQC.	YES
Freshwater Chronic National Recommended WQC.	YES
Human Health Water and Organism National Recommended WQC.	YES
Human Health Organism Only National Recommended WQC.	YES
Drinking Water MCL	YES
Fish Ingestion NEHC for Mink.	YES
Fish Ingestion NEHC for Eagles.	YES
Adverse Reproductive Effects in Fish due to Selenium.	YES
Adverse Reproductive Effects in Mallards due to Selenium.	YES
Non-Cancer Reference Dose for Child (Recreational and Subsistence fishers).	YES
Non-Cancer Reference Dose for Adult (Recreational and Subsistence fishers).	YES
Arsenic Cancer Risk for Child (Recreational and Subsistence fishers).	YES
Arsenic Cancer Risk for Adult (Recreational and Subsistence fishers).	YES

Acronyms: MCL (Maximum Contaminant Level); NEHC (No Effect Hazard Concentration); WQC (Water Quality Criteria).

[a] The IRW model encompasses a total of 163 immediate receiving waters (144 rivers and streams; 19 lakes, ponds, and reservoirs) and loadings from 143 steam electric power plants.

1. Improvements in Surface Water and Ground Water Quality

EPA estimates a significant number of environmental and ecological improvements and reduced impacts to wildlife and humans from reductions in pollutant loadings under the final rule. More specifically, the environmental assessment evaluated (a) improvements in water quality, (b) reduction in impacts to wildlife, (c) reduction in number of receiving waters with potential human health cancer risks, (d) reduction in number of receiving waters with potential to cause non-cancer human health effects, (e) reduction in nutrient impacts, (f) reduction in other environmental impacts, and (g) other unquantified environmental improvements.

[53] See the EA for the details and amounts of the projected improvements.

EPA expects significantly reduced contamination levels in surface waters and sediments under the final rule. EPA estimates that reduced pollutant loadings to surface waters will significantly improve water quality by reducing pollutant concentrations by an average of 56 percent within the immediate receiving waters of steam electric power plants where additional treatment technologies are installed as a result of this final rule. Based on the water quality component of the IRW model, which compares modeled receiving water concentrations to national recommended WQC and MCLs to assess changes in receiving water quality, the pollutants with the greatest number of water quality standard exceedances under baseline pollutant loadings include: Total arsenic, total thallium, total selenium, and dissolved cadmium. EPA estimates that almost half of the immediate receiving waters exceed a water quality standard under baseline loadings. EPA estimates that the number of immediate receiving waters with aquatic life exceedances, which are driven by high total selenium and dissolved cadmium concentrations, will be reduced under the final rule. EPA also estimates that the number of immediate receiving waters with human health water quality standards exceedances, primarily driven by high total arsenic and total thallium concentrations, will be reduced under the final rule.

Selenium is one of the primary pollutants documented in the literature as causing environmental impacts to fish and wildlife. EPA calculates that total selenium receiving water concentrations will be reduced by two-thirds under the final rule, leading to a reduction in the number of immediate receiving waters exceeding the freshwater chronic criteria for selenium.

While the case-study models and IRW model produced generally similar results for the five receiving waters included in both analyses, the case-study model reveals additional potential for baseline impacts to water quality, aquatic life, and human health that are not reflected in the IRW model. Case-study modeling also reveals that these potential impacts can extend beyond the immediate receiving water and into downstream waters, leading to the potential for more widespread environmental and human health effects than those shown with the IRW model. This is particularly true regarding water quality standard exceedances; in four of the five receiving waters included in both analyses, the case-study model indicates that the final rule will result in further reductions in water quality standard exceedances beyond those reflected in the IRW model.

As discussed in the EA, the RSEI modeling indicates that surface waters downstream from steam electric power plant wastewater discharges will also achieve water quality improvements under the final rule.

This final rule will also potentially help to both reduce ground water contamination and improve the availability of ground water resources by complementing the CCR rule. This rule provides strong incentives for plants to greatly reduce, if not entirely eliminate, disposal and treatment of steam electric power plant wastewater in unlined surface impoundments.

2. Reduced Impacts to Wildlife

EPA expects that once the rule is implemented the number of immediate receiving waterbodies with potential impacts to wildlife will begin to be reduced by more than a half compared to baseline conditions under the final rule.

EPA determined that steam electric power plant wastewater discharges into lakes pose the greatest risk to piscivorous (fish eating) wildlife, with almost a half of lakes exceeding a protective benchmark for minks or eagles under baseline pollutant loadings (compared to about a third of rivers). Mercury and selenium are the primary pollutants with the greatest number of receiving waters with benchmark exceedances. EPA estimates that this rule will reduce the number of immediate receiving waters exceeding the benchmark for minks and eagles by approximately half for mercury and selenium. Additionally, as discussed in the EA, the downstream RSEI modeling indicates that surface waters downstream from steam electric power plant wastewater discharges will also achieve improvements in these wildlife benchmarks under the final rule.

For the final rule, EPA also performed modeling to estimate the risk of adverse reproductive effects among fish (*e.g.,* reduced larvae survival) and waterfowl (*e.g.,* reduced egg hatchability) with dietary exposure to selenium from steam electric power plant wastewater. Based on the water quality output from the IRW model, EPA determined that approximately 15 percent of immediate receiving waters contain selenium concentrations that present at least a ten percent risk of adverse reproductive effects among fish or waterfowl that consume prey from those waterbodies. Under the final rule, EPA estimates that the count of immediate receiving waters presenting these reproductive risks will be reduced by more than half. This indicates that the final rule will reduce the long-term bioaccumulative impact of selenium (and possibly other bioaccumulative pollutants) throughout aquatic ecosystems.

In addition, EPA estimates that the improvements to water quality, discussed above, will improve aquatic and wildlife habitats in the immediate and downstream receiving waters from steam electric power plant discharges. EPA determined that these water quality and habitat improvements will enhance efforts to protect threatened and endangered species. EPA identified four species with a high vulnerability to changes in water quality whose recovery will be enhanced by the pollutant reductions associated with the final rule.

3. Reduced Human Health Cancer Risk

EPA estimates that reductions in arsenic loadings from the final rule will result in a reduction in potential cancer risks to humans that consume fish exposed to steam electric power plant discharges. In addition, based on the downstream RSEI modeling, EPA estimates that numerous river miles downstream from steam electric discharges contain fish contaminated with inorganic arsenic that present cancer risks to at least one of the evaluated cohorts. The final rule substantially reduces this number of miles.

4. Reduced Threat of Non-Cancer Human Health Effects

Exposure to toxic bioaccumulative pollutants poses risk of systemic and other effects to humans, including effects on the circulatory, respiratory, or digestive systems, and neurological and developmental effects. EPA estimates the final rule will significantly reduce the number of receiving waters with the potential to cause non-cancer health effects in humans who consume fish exposed to steam electric power plant pollutants.

Under baseline pollutant loadings, EPA determined that about half of immediate receiving waters present non-cancer health risks for one or more of the human cohorts due to elevated pollutant levels in fish. The final rule, once implemented, will begin to reduce this amount by approximately 50 percent for all the human cohorts that were evaluated. Non-cancer risks are caused primarily by mercury (as methylmercury), total thallium, and total selenium, and to a lesser degree, total cadmium pollutant loadings. Additionally, as discussed in the EA, the downstream RSEI modeling indicates that the final rule substantially reduces the prevalence of downstream waters with contaminated fish that present non-cancer health risks to at least one of the human cohorts.

In addition to the assessment of non-cancer impacts described above, EPA also evaluated the adverse health effects to children who consume fish contaminated with lead from steam electric power plant wastewater. EPA estimates that the final rule will significantly reduce the associated IQ loss among children who live in recreational angler and subsistence fisher households. The final rule will also reduce the incidence of other health effects associated with lead exposure among children, including slowed or delayed growth, delinquent and anti-social behavior, metabolic effects, impaired heme synthesis, anemia, and impaired hearing. The final rule will also reduce IQ loss among children exposed in utero to mercury from maternal fish consumption. Section XIV.B.1 provides additional details on the benefits analysis of these reduced IQ losses.

The final rule will also result in additional non-cancer human health improvements beyond those discussed above, including reduced health hazards due to exposure to contaminants in waters that are used for recreational purposes (*e.g.,* swimming).

5. Reduced Nutrient Impacts

The primary concern with nutrients (nitrogen and phosphorus) in steam electric power plant discharges is the potential for contributing to adverse impacts in waterbodies that receive nutrient discharges from multiple sources. Excessive nutrient loadings to receiving waters can significantly affect the ecological stability of freshwater and saltwater aquatic ecosystems and pose health threats to humans from the generation of toxins by cyanobacteria, which can thrive in nitrogen driven algal blooms (DCN SE04505).

Nine percent of surface waters receiving steam electric power plant wastewater discharges are impaired for nutrients. Although the concentration of nitrogen present in steam electric power plant discharges from any individual power plant is relatively low, the total nitrogen loadings from a single plant can be significant due to large wastewater discharge flow rates.

EPA projects that the final rule will reduce total nutrient loadings by steam electric power plants in their immediately downstream receiving waters by more than 99 percent. Section XIV provides additional details on the water quality benefits analysis of nutrient reductions, as determined using the SPARROW (Spatially Referenced Regressions On Watershed attributes) model.

E. Unquantified Environmental and Human Health Improvements

The environmental assessment focused primarily on the quantification of environmental improvements within rivers and lakes from post-compliance pollutant reductions for toxic bioaccumulative pollutants and excessive nutrients. While extensive, the environmental improvements quantified do not encompass the full range of improvements anticipated to result from the final rule simply because some of the improvements have no method for measuring a quantifiable or monetizable improvement. EPA estimates post-compliance pollutant reductions from the final rule to result in much greater improvements than those quantified for wildlife, human health and the environment by:

- Reducing loadings of bioaccumulative pollutants to the broader ecosystem, resulting in the reduction of long-term exposures and sub-lethal ecological effects;
- Reducing sub-lethal chronic effects of toxic pollutants on aquatic life not captured by the national recommended WQC;
- Reducing loadings of pollutants for which EPA did not perform water quality modeling in support of the environmental assessment (*e.g.,* boron, manganese, aluminum, vanadium, and iron);
- Mitigating impacts to aquatic and aquatic-dependent wildlife population diversity and community structures;
- Reducing exposure of wildlife to pollutants through direct contact with combustion residual surface impoundments and constructed wetlands built as treatment systems at steam electric power plants; and
- Reducing the potential for the formation of harmful algal blooms.

Data and analytical limitations prevent modeling the scale and complexity of the ecosystem processes potentially impacted by steam electric power plant wastewater, resulting in the inability to quantify all potential improvements. However, documented site-specific impacts in the literature reinforce that these impacts are common in the environments surrounding steam electric power plants and fully support the conclusion that reducing pollutant loadings will further reduce risks to human health and wildlife and prevent damage to the environment.

Although the environmental assessment quantifies impacts to wildlife that consume fish contaminated with pollutants from steam electric power plant wastewater, it does not capture the full range of exposure pathways through which bioaccumulative pollutants can enter the surrounding food web. Wildlife can encounter toxic bioaccumulative pollutants from discharges of the evaluated wastestreams through a variety of exposure pathways such as direct exposure, drinking water, consumption of contaminated vegetation, and consumption of contaminated prey other than fish and invertebrates. Therefore, the quantified improvements underestimate the complete loadings of bioaccumulative pollutants that can impact wildlife in the ecosystem. The final rule will lower the total amount of toxic bioaccumulative pollutants entering the food web near steam electric power plants.

EPA also estimates that reductions in pollutant loadings will lower the occurrence of sub-lethal effects associated with many of the pollutants in steam electric power plant wastewater that are not captured by comparisons with national recommended WQC for aquatic life. Chronic effects such as decreased reproductive success, changes in metabolic rates, decreased growth rates, changes in morphology (*e.g.,* fin erosion, oral deformities), and changes in behavior (*e.g.,* swimming ability, ability to catch prey, ability to escape from predators) that can negatively affect long-term survival, are well documented in the literature as occurring in aquatic environments near steam electric power plants. Reductions in organism survival rates from chronic effects such as abnormalities can alter interspecies relationships (*e.g.,* declines in the abundance or quality of prey) and prolong ecosystem recovery. Additionally, EPA was unable to quantify changes to aquatic and wildlife population diversity and community dynamics; however, population effects (decline in number and type of organisms present) caused by exposure to steam electric power plant wastewater are well documented in the literature. Changes in aquatic populations can alter the structure and function of aquatic communities and cause cascading effects within the food web that result in long-term impacts to ecosystem dynamics. EPA estimates that post-compliance pollutant loading reductions associated with the final rule will lower the stressors that can cause alterations in population and community dynamics and improve the overall function of ecosystems surrounding steam electric power plants, as well as help resolve issues faced in other national ecosystem protection programs such as the Great Lakes program, the National Estuaries program, and the 303(d) impaired waters program.

The post-compliance pollutant reductions associated with the final rule will also decrease the environmental impacts to wildlife exposed to pollutants through direct contact with surface impoundments and constructed wetlands at steam electric power plants. Documented site-specific impacts demonstrate that wildlife living in close proximity to combustion residual impoundments exhibit elevated levels of arsenic, cadmium, chromium, lead, mercury, selenium, and vanadium. Multiple studies have linked these ''attractive nuisance'' areas (contaminated impoundments at a steam electric power plant that attract wildlife for nesting or feeding) to diminished reproductive success. EPA estimates that the post-compliance pollutant reductions will decrease the exposure of wildlife populations to toxic pollutants and reduce the risks for impacts on reproductive success.

F. Other Improvements

Other improvements will occur to other resources that are associated directly or indirectly with the final rule. These include aesthetic and recreational improvements, reduced economic impacts such as clean up and treatment costs in response to contamination or impoundment failures, reduced injury associated with pond failures, reduced ground water contamination, support for threatened and endangered species, reduced water usage and reduced air emissions. Section XIV provides additional details on the monetized benefits of these improvements.

XIV. Benefits Analysis

This section summarizes EPA's estimates of the national environmental benefits expected to result from reduction in steam electric power plant wastewater discharges described in Section X and the resultant environmental effects summarized in Section XIII. The BCA Report provides additional details on benefits methodologies and analyses, including uncertainties and limitations. The analysis methodology is generally the same as that used by EPA for analysis of the proposed rule, but with revised inputs and assumptions that reflect updated data and address comments the Agency received on the proposed rule, including additional categories of benefits the Agency analyzed for the final rule.

A. Categories of Benefits Analyzed

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

TABLE XIV–1—BENEFIT CATEGORIES ASSOCIATED WITH FINAL RULE

Benefit category	Quantified and monetized	Quantified but not monetized	Neither quantified nor monetized
1. Human Health Benefits from Surface Water Quality Improvements			
Reduced incidence of cancer from arsenic exposure via fish consumption	X		
Reduced incidence of cardiovascular disease from arsenic exposure via fish consumption		X	
Reduced incidence of cardiovascular disease from lead exposure via fish consumption	X [a]		
Reduced incidence of other cancer and non-cancer adverse health effects (*e.g.,* reproductive, immunological, neurological, circulatory, or respiratory toxicity) due to exposure to arsenic, lead, cadmium, and other toxics from fish consumption		X	
Reduced IQ loss in children from lead exposure via fish consumption	X		
Reduced need for specialized education for children from lead exposure via fish consumption	X		
Reduced in utero mercury exposure via maternal fish consumption	X		
Reduced health hazards from exposure to pollutants in waters used recreationally (*e.g.,* swimming)			X
2. Ecological Conditions and Recreational Use Benefits from Surface Water Quality Improvements			
Benefits from improvements in surface water quality, including: Improved aquatic and wildlife habitat; enhanced water-based recreation, including fishing, swimming, boating, and near-water activities; increased aesthetic benefits, such as enhancement of adjoining site amenities (*e.g.,* residing, working, traveling, and owning property near the water [b]; and non-use value (existence, option, and bequest value from improved ecosystem health) [b]	X		
Benefits from improved protection of threatened and endangered species	X		
Reduced sediment contamination			X
3. Market and Productivity Benefits			
Reduced impoundment failures (monetized benefits include avoided cleanup costs, transaction costs, and environmental damages; non-quantified benefits include avoided injury)	X		X
Reduced water treatment costs for municipal drinking water, irrigation water, and industrial process			X
Improved commercial fisheries yields			X
Increased tourism and participation in water-based recreation			X
Increased property values from water quality improvements			X
Increased ability to market coal combustion byproducts	X [a]		

TABLE XIV–1—BENEFIT CATEGORIES ASSOCIATED WITH FINAL RULE—Continued

Benefit category	Quantified and monetized	Quantified but not monetized	Neither quantified nor monetized
Reduced maintenance dredging in navigational waterways and reservoirs from reduction in sediment discharges	X [a]		
4. Air-Related Benefits			
Human health benefits from reduced morbidity and mortality from exposure to NO_X, SO_2 and particulate matter ($PM_{2.5}$)	X		
Avoided climate change impacts from CO_2 emissions	X		
5. Benefits from Reduced Water Withdrawals			
Increased availability of ground water resources	X		
Reduced impingement and entrainment of aquatic organisms			X
Reduced susceptibility to drought			X

[a] Monetized benefit category added for the final rule.
[b] These values are implicit in the total willingness to pay (WTP) for water quality improvements.

The following section summarizes EPA's analysis of the benefits that the Agency was able to quantify and monetize (identified in the second column of Table XIV–1). The final rule will also provide additional benefits that the Agency was not able to monetize. The BCA Report further describes some of these additional non-monetized benefits.

B. Quantification and Monetization of Benefits

1. Human Health Benefits From Surface Water Quality Improvements

Reduced pollutant discharges from steam electric power plants generate human health benefits in a number of ways. As described in Section XIII, exposure to pollutants in steam electric power plant discharges via consumption of fish from affected waters can cause a wide variety of adverse health effects, including cancer, kidney damage, nervous system damage, fatigue, irritability, liver damage, circulatory damage, vomiting, diarrhea, brain damage, IQ loss, and many others. Because the final rule will reduce discharges of steam electric pollutants into waterbodies that receive, or are downstream from, these discharges, it is likely to result in decreased incidences of associated illnesses.

Due to data limitations and uncertainties, EPA is able to monetize only a subset of the health benefits associated with reductions in pollutant discharges from steam electric power plants. EPA analyzed the following measures of human health-related benefits: Reduced lead-related IQ loss in children aged zero to seven from fish consumption; reduced cardiovascular disease in adults from lead and arsenic exposure from fish consumption; reduced mercury-related IQ loss in children exposed in utero due to maternal fish consumption; and reduced cancer risk in adults due to arsenic exposure from fish consumption. EPA monetized these human health benefits by estimating the change in the expected number of individuals experiencing adverse human health effects in the populations exposed to steam electric discharges and/or reduced exposure levels, and valuing these changes using a variety of monetization approaches.

These are not the only human health benefits expected to result from the final rule. EPA also estimated additional human health benefits derived from changes in air emissions. These additional benefits are discussed separately in Section XIV.B.4.

a. Monetized Human Health Benefits From Surface Water Quality Improvements

EPA estimated health risks from the consumption of contaminated fish from waterbodies within 50 miles of households. EPA used Census Block population data, state-specific average fishing rates, and data on fish consumption advisories to estimate the exposed population. EPA used cohort-specific fish consumption rates and waterbody-specific fish tissue concentration estimates to calculate exposure to steam electric pollutants. Cohorts were defined by age, sex, race/ethnicity, and fishing mode (recreational/subsistence). EPA used these data to quantify and monetize the following six categories of human health benefits, which are further detailed in the BCA Report:

- Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption.
- Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption.
- Benefits from Reduced Incidence of Cardiovascular Disease from Lead Exposure via Fish Consumption.
- Benefits of Reduced In Utero Mercury Exposure via Maternal Fish Consumption.
- Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption.
- Benefits from Reduced Incidence of Cardiovascular Disease from Arsenic Exposure via Fish Consumption.

Table XIV–2 summarizes monetized human health benefits from surface water quality improvements. EPA estimates that the final rule will provide human health benefits valued at $16.5 to $17.9 million annually, using a three percent discount rate, and $11.3 to $11.6 million, using a seven percent discount rate. In addition, EPA estimated health benefits associated with changes in air emissions, as discussed in Section XIV.B.4.

TABLE XIV–2—HUMAN HEALTH BENEFITS FROM SURFACE WATER QUALITY IMPROVEMENTS

Benefit category	Annualized benefits (million 2013$)
3% Discount Rate	
Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption [a]	$1.0 ($0.8 to $1.1)
Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption	<0.1
Benefits from Reduced Incidence of Cardiovascular Disease (CVD) from Lead Exposure via Fish Consumption	12.8
Benefits of Reduced In Utero Mercury Exposure via Maternal Fish Consumption [a]	3.5 (2.9 to 4.0)
Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption	<0.1
Subtotal [b]	16.5 to 17.9 (15.2 to 16.7)
7% Discount Rate	
Benefits from Reduced IQ Loss in Children from Lead Exposure via Fish Consumption [a]	0.2 (0.1 to 0.2)
Benefits from Reduced Need for Specialized Education for Children from Lead Exposure via Fish Consumption	<0.1
Benefits from Reduced Incidence of CVD from Lead Exposure via Fish Consumption	10.7
Benefits of Reduced In Utero Mercury Exposure via Maternal Fish Consumption [a]	0.6 (0.5 to 0.7)
Benefits from Reduced Incidence of Cancer from Arsenic Exposure via Fish Consumption	<0.1
Subtotal [b]	11.4 (10.7 to 11.0)

[a] Low end is based on the assumption that the loss of one IQ point results in the loss of 1.76% of lifetime earnings (following Schwartz, 1994); high end is based on the assumption that the loss of one IQ point results in the loss of 2.38% of lifetime earnings (following Salkever, 1995).
[b] Totals may not add up due to independent rounding.

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

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

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

a. Improvements in Surface Water Quality

EPA expects the final rule will improve aquatic habitats and human welfare by reducing concentrations of harmful pollutants such as arsenic, cadmium, chromium, lead, mercury, selenium, nitrogen, phosphorus, and suspended sediment. As a result, some of the waters that were not usable for recreation under the baseline discharge conditions may become usable following the rule, thereby benefiting recreational users. Waters that have been used for recreation under the baseline conditions can become more attractive by making recreational trips even more enjoyable. The final rule is also expected to generate nonuse benefits from bequest, altruism, and existence motivations. Individuals may value knowing that water quality is being maintained, ecosystems are being protected, and species populations are healthy, independent of any use.

EPA estimates that approximately 19,600 reach miles will improve as a result of the final rule, as indicated by a higher post-compliance water quality index (WQI) score. The WQI translates water quality measurements, gathered for multiple parameters that are indicative of various aspects of water quality, into a single numerical indicator that reflects achievement of quality consistent with the suitability for certain uses.

EPA estimated monetized benefit values using a revised version of the meta-regression of surface water valuation studies used in the benefit-cost analysis of the proposed ELGs (DCN SE03172). Using a meta-dataset of 51 studies published between 1985 and 2011, EPA developed a meta-regression model that predicts how marginal willingness to pay (WTP) for water quality improvements depends on a variety of methodological, population, resource, and water quality change characteristics. EPA developed two versions of the meta-regression model: The first model (Model 1) provides a central estimate of non-market benefits, while the second model (Model 2) provides a range of estimates to account for uncertainty in the resulting WTP values. Chapter 4 of the BCA provides more details on the meta-regression models and analysis.

EPA estimated economic values of water quality improvements at the Census block group level. Water quality improvements are measured as a length-weighted average of the changes in WQI for waters within 100 miles of the center of each Census block; these waters includes both waters improving as a result of the final rule and waters not affected by steam electric plant discharges but which may be substitutes for improved waters.

EPA first estimated annual household marginal WTP values for a given Census block group using the meta- regression models (Model 1 and Model 2) and multiplied this marginal WTP by the annual average water quality change for the Census block group to obtain the annual household WTP.

EPA then estimated total WTP values by multiplying the annual household WTP values by the total number of households within a Census block group. EPA annualized the stream of future benefits, expressed in 2013 dollars, using both 3 and 7 percent discount rates.

Total national benefits are the sum of estimated Census block group-level WTP across all block groups for which at least one waterbody within 100 miles is improved.

Average annual household WTP estimates for the final ELGs range from $0.32 on the low end to $1.77 on the high end, with a central estimate of $0.45. An estimated 84.5 million households reside in Census block groups within 100 miles of affected reaches. The total annualized benefits of water quality improvements resulting from reduced metal, nutrient, and sediment pollution in the approximately 19,600 reach miles improving under the final ELGs range from $23.2 million to $129.5 million with a central estimate of $31.3 million using a three percent discount rate and $18.5 million to $103.4 million with a central estimate of $25.1 million using a seven percent discount rate.

b. Benefits to Threatened and Endangered Species

To assess the potential for impacts on T&E species (both aquatic and terrestrial), EPA analyzed the overlap between waters currently exceeding wildlife-based national recommended WQC, but expected to have no wildlife national recommended WQC exceedances as a result of the final rule, and the known critical habitat locations of approximately 631 T&E species. EPA examined the life history traits of potentially affected T&E species to categorize species by the potential for population impacts likely to occur as a result of changes in water quality. Chapter 5 of the BCA Report details the methodology.

EPA determined that of 15 species whose recovery may be enhanced by the final rule, three fish species and one salamander species may experience changes in population growth rates as a result of the final rule. To quantify the benefits to T&E species, EPA weighted minimal population growth assumptions (0.5, 1, or 1.5 percent) by the percent of reaches used by T&E species that are expected to meet wildlife-based national recommended WQC because of the final rule.

The T&E species expected to benefit from the rule include one species of sturgeon and two species of minnows. All of these species have nonuse values, including existence, bequest, altruistic, and ecological service values, apart from human uses or motives. EPA estimated the economic values of increased T&E species populations using a benefit function transfer approach based on a meta-analysis of 31 stated preference studies eliciting WTP for these changes (Richardson and Loomis 2009). Because the underlying metadata do not include amphibian valuation studies, EPA was unable to monetize any benefits for potential population increases of Hellbender salamander. EPA estimates annualized benefits to T&E species of approximately $0.02 million, using either a three percent or seven percent discount rate.

3. Market and Productivity Benefits

a. Benefits From Reduced Magnitude of Impoundment Failures

Operational changes that plants choose to make to meet requirements in the final rule may cause some plants to reduce their reliance on impoundments to handle their waste. EPA expects these changes to reduce the magnitude of impoundment failures and the resulting accidental, and sometimes catastrophic releases, of CCRs.

To assess the benefits associated with changes in impoundment use, EPA estimated the costs associated with expected releases under baseline conditions (assuming no change in operations relative to expected operations under the CCR and CPP rules) and for projected reductions in the amount of CCR waste managed by impoundments. EPA performed the calculations for each of the 883 to 925 impoundments identified at steam electric power plants,[54] and for each year between 2016 and 2042. EPA then calculated benefits as the difference between expected release costs for the final rule and expected release costs under baseline conditions.

To estimate the number of release events that may be avoided as a result of the ELGs, EPA followed the same approach used by EPA for its RIA for the CCR rule. The approach relies on estimated failure rates and capacity factors for two different types of releases (wall breach and other release) and two categories of impoundments (big and small). For the final steam electric ELG rule analysis, EPA used baseline release-rate assumptions that account for changes projected to result from implementation of the CCR rule. As detailed in Chapter 6 of the BCA Report, EPA calculated the expected costs of an impoundment release, including cleanup, natural resource damages (NRD),[55] and transaction costs.[56]

Using the approach above, EPA estimates the annualized benefits of the final rule are $95.6 million to $102.9 million using a three percent discount rate, and $77.7 million to $83.7 million using a seven percent discount rate.

b. Benefits From Increased Marketability of Coal Combustion Residuals

The final rule may enhance the ability of steam electric power plants to market coal combustion byproducts for beneficial use by converting from wet to dry handling of fly ash, bottom ash and FGD waste. In particular, EPA evaluated the potential benefits from the increased marketability of fly ash as a substitute for Portland cement in concrete production and fly and bottom ashes as substitutes for sand and gravel in fill applications. Based on the change in the quantity of CCRs handled dry and state-level demand for beneficial use applications of CCRs, EPA calculated avoided disposal costs and life-cycle benefits from avoiding the production of virgin materials. Chapter 10 of the BCA Report details the methodology.

EPA estimates the annualized benefits of the final rule at $30.8 million using a three percent discount rate, and $31.1 million using a seven percent discount rate.

4. Air-Related Benefits (Human Health and Avoided Climate Change Impacts)

EPA expects the final rule to affect air pollution through three main mechanisms: (1) Additional auxiliary electricity use by steam electric power

[54] The 883 to 925 impoundments represent the estimated number of impoundments expected to operate after accounting for the projected effects of the CCR rule and CPP rule, relative to the initial universe of 1,070 impoundments located at 347 plants (out of the total universe of 1,080 steam electric plants). The range of impoundments reflects different assumptions regarding the projected effects of the CPP rule on impoundment operations. See Chapter 6 in the BCA for more information.

[55] NRD include only the resource restoration and compensation values; they do not include cleanup costs (or legal costs).

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

plants to operate wastewater treatment, ash handling, and other systems, which EPA predicts that plants will use to meet the new effluent limitations and standards; (2) additional transportation-related air emissions due to the increased trucking of CCR waste to landfills; and (3) the change in the profile of electricity generation due to the relatively higher cost to generate electricity at plants incurring compliance costs for the final ELGs. Changes in the profile of generation can result in lower or higher emissions of air pollutants because of variability in emission factors for different types of electric generating units. For this analysis, the changes in air emissions are based on the change in dispatch of generation units projected by IPM V5.13, as a result of overlaying the costs of meeting the final ELGs onto steam electric generating units' production costs. As discussed in Section IX.C.1, the IPM analysis accounts for the effects of other regulations affecting the electric power sector.

EPA estimated the human health and other benefits resulting from net changes in air emissions of three pollutants: NO_X, SO_2, and CO_2. NO_X and SO_X are known precursors to fine particles ($PM_{2.5}$), a criteria air pollutant that has been associated with a variety of adverse health effects—most notably, premature mortality, non-fatal heart attacks, hospital admissions, emergency department visits, upper and lower respiratory symptoms, acute bronchitis, aggravated asthma, lost work days, and acute respiratory symptoms. CO_2 is a key greenhouse gas that is linked to a wide range of climate change effects.

EPA used average benefit-per-ton estimates to value benefits of changes in NO_X and SO_2 emissions, and social cost of carbon (SCC) estimates to value benefits of changes in CO_2 emissions. The calculations are based on the net changes in air emissions and reflect the net reductions in CO_2 and NO_X emissions during the entire period of analysis, and the net increase in SO_2 emissions in 2023–2027, and net decline in SO_2 emissions during the rest of the period. The values are specific to the years 2016, 2020, 2025, and 2030. Because they are almost linear as a function of year, EPA interpolated benefits per ton values for the intermediate years (*e.g.,* between 2020 and 2025) and projected values for the years from 2031 through 2042 by linear regression. While extrapolating introduces some uncertainty, as it does not account for meteorological and air quality changes over time, this approach is a reasonable one, given available information.

Chapter 7 of the BCA Report provides the details of this analysis. As shown in Table XIV–3, EPA estimates that the final rule will provide human health benefits valued at $144.7 million using a three percent discount rate, and $108.8 million using a seven percent discount rate. The rule is expected to provide air-related benefits from changes in CO_2 emissions valued at $139.8 million, using a three percent discount rate.

TABLE XIV–3—ANNUALIZED BENEFITS OF CHANGES IN NO_X, SO_2, AND CO_2 AIR EMISSIONS

[Million 2013$][a]

Benefit category	3 Percent discount rate	7 Percent discount rate [b]
Human health benefits from reduced morbidity and mortality from exposure to NO_X, SO_2 and particulate matter ($PM_{2.5}$)	$144.7	$108.8
Avoided climate change impacts from CO_2 emissions [b]	$139.8	$139.8
Total	$284.5	$248.6

[a] Consistent with the assumptions used for the IPM analyses described in Section IX.C, EPA estimated the benefits relative to a baseline that includes the CPP rule.

[b] EPA used the SCC based on a three percent discount rate to estimate values presented for the seven percent discount rate. EPA uses three percent to discount CO_2-related benefits and seven percent to discount benefits from changes in NO_X and SO_2 emissions. See Section 7.1 of the BCA for details on the methodology.

5. Benefits From Reduced Water Withdrawals (Increased Availability of Ground Water Resources)

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

EPA estimated the benefits of reduced ground water withdrawals based on avoided costs of ground water supply. For each relevant plant, EPA multiplied the reduction in ground water withdrawal (in gallons per year) by water costs of about $1,231 per acre-foot. Chapter 8 of the BCA Report provides the details of this analysis. EPA estimates the annualized benefits of reduced ground water withdrawals are less than $0.1 million annually. Due to data limitations, EPA was not able to monetize the benefits from reduced surface water withdrawals. Chapter 8 of the BCA Report provides additional detail on benefits from reducing surface water withdrawals.

C. Total Monetized Benefits

Using the analysis approach described above, EPA estimates annual total benefits of the final rule for the five monetized categories at approximately $450.6 million to $565.6 million (at a three percent discount rate and $387.3 million to $478.4 million at a seven percent discount rate) (Table XIV–4).

TABLE XIV–4—SUMMARY OF TOTAL ANNUALIZED MONETIZED BENEFITS OF FINAL RULE

Benefit category	Annualized monetized benefits (million 2013$)
3 Percent Discount Rate	
Human Health Benefits from Surface Water Improvements [a d]	$16.5 to $17.9

TABLE XIV–4—SUMMARY OF TOTAL ANNUALIZED MONETIZED BENEFITS OF FINAL RULE—Continued

Benefit category	Annualized monetized benefits (million 2013$)
Improved Ecological Conditions and Recreational Uses [a b d]	$23.3 to $129.5
Market and Productivity Benefits (impoundment failure and ash marketing)	$126.4 to $133.7
Human Health Benefits from Air Quality Improvements	$144.7
Other Air-Related Benefits (climate change)	$139.8
Reduced Water Withdrawals	<$0.1
Total benefits	$450.6 to $565.6
7 Percent Discount Rate	
Human Health Benefits from Surface Water Improvements [a]	$11.3 to $11.6
Improved Ecological Conditions and Recreational Uses [a b]	$18.6 to $103.4
Market and Productivity Benefits (impoundment failure and ash marketing)	$108.8 to $114.8
Human Health Benefits from Air Quality Improvements	$108.8
Other Air-Related Benefits [c] (climate change)	$139.8
Reduced Water Withdrawals	<$0.1
Total benefits	$387.3 to $478.4

[a] Values represent mean benefit estimates. Totals may not add up due to independent rounding.
[b] There may be some, expected to be small, overlap between the willingness-to-pay (WTP) for surface water quality improvements and WTP for benefits to threatened and endangered species.
[c] EPA used the SCC based on a three percent discount rate and discounted CO_2-related benefits using a three percent discount rate, as compared to benefits in other categories, which are discounted using the seven percent discount rate.
[d] Estimates for this benefit category do not reflect revised pollutant loadings, which could result in lower monetized benefits. See Section 1.4.3 of the Benefit Cost Analysis for this rule for details.

D. Other Benefits

The monetized benefits of this final rule do not account for all benefits because, as described above, EPA is unable to monetize some categories. Examples of benefit categories not reflected in these estimates include other cancer and non-cancer health benefits, reduced cost of drinking water treatment, avoided ground water contamination corrective action costs, reduced vulnerability to drought, and reduced aquatic species mortality from reduced surface water withdrawal. The BCA Report discusses these benefits qualitatively, indicating their potential magnitude where possible.

XV. Cost-Effectiveness Analysis

EPA often uses cost-effectiveness analysis in the development and revision of ELGs to evaluate the relative efficiency of alternative regulatory options in removing toxic pollutants from effluent discharges to the nation's waters. Although not required by the CWA, and not a determining factor for establishing BAT and PSES, cost-effectiveness analysis can be a useful tool for describing regulatory options that address toxic pollutants.

A. Methodology

The cost-effectiveness of a regulatory option is defined as the incremental annual cost (in 1981 constant dollars to facilitate comparison to ELGs for other industrial categories promulgated over different years) per incremental toxic-weighted pollutant removals for that option. This definition includes the following concepts:

Toxic-weighted removals. The estimated reductions in pollution discharges, or pollutant removals, are adjusted for toxicity by multiplying the estimated removal quantity for each pollutant by a normalizing toxic weight (toxic weighting factor). The toxic weight for each pollutant measures its toxicity relative to copper, with more toxic pollutants having higher toxic weights. The use of toxic weights allows the removals of different pollutants to be expressed on a constant toxicity basis as toxic pound-equivalents (lb-eq). In the case of indirect dischargers, the removal also accounts for the effectiveness of treatment at POTWs and reflects the toxic-weighted pounds remaining after POTW treatment. The cost-effectiveness analysis does not address the removal of conventional pollutants (*e.g.,* TSS) or nutrients (nitrogen, phosphorus), nor does it address the removal of bulk parameters, such as COD.

Annual costs. The costs used in the cost-effectiveness analysis are the estimated annualized pre-tax costs described in Section IX, restated in 1981 dollars as a convention to allow comparisons with the reported cost effectiveness of other effluent guidelines.

The result of the cost-effectiveness calculation represents the unit cost (in constant 1981 dollars) of removing the next pound-equivalent of pollutants. EPA calculates cost-effectiveness separately for direct and indirect dischargers. EPA notes that only three steam electric power plants are estimated to incur costs associated with the final PSES requirements, as compared to 130 plants estimated to incur costs associated with the final BAT requirements.

Appendix F of the RIA details the analysis.

B. Results

Collectively, the final BAT requirements have a cost-effectiveness ratio of $134/lb-eq ($1981). This cost-effectiveness ratio is well within the range of cost-effectiveness ratios for BAT requirements in other industries. A review of approximately 25 of the most recently promulgated or revised BAT limitations shows BAT cost-effectiveness ranging from less than $1/lb-eq (Inorganic Chemicals) to $404/lb-eq (Electrical and Electronic Components), in 1981 dollars.

Collectively, the final PSES requirements have a cost effectiveness of $1,228/lb-eq ($1981). This ratio is higher than the cost-effectiveness for PSES of other industries, which range from less than $1/lb-eq (Inorganic Chemicals) to $380/lb-eq (Transportation Equipment Cleaning), in

1981 dollars, based on a review of approximately 25 of the most recently promulgated or revised categorical pretreatment standards. As noted above, however, very few plants (three) are indirect dischargers and the cost-effectiveness for one of the three indirect dischargers significantly elevates the value for all three combined. EPA calculated costs for this plant based on a full conversion of its bottom ash handling system to dry handling. However, it is more likely that this plant would choose to implement modifications that would enable it to completely recycle its bottom ash transport water in order to meet the zero discharge standard, rather than undertake a full conversion. In that event, the costs to this indirect discharger—and consequently the cost-effectiveness value for all indirect dischargers, combined—would be lower.

Collectively, cost-effectiveness for the entire rule (BAT and PSES) is $136/lb-eq ($1981).

For the purposes of calculating pollutant loadings under this action, EPA's analysis first handled non-detect values in the reported data by replacing them with a value of one-half of the detection level for the observation that yielded the non-detect. This methodology is standard procedure for the ELG program as well as Clean Water Act assessment and permitting, Safe Drinking Water Act monitoring, and Resource Conservation and Recovery Act and Superfund programs; and this approach is consistent with previous ELGs.

In their comments on the proposed rule, commenters raised the concern that for some pollutants the loadings calculations (particularly for bottom ash) were biased high as a result of high non-detected values in the reported data. These high non-detected values were the result of not using sufficiently sensitive methods. The view was expressed that, should the non-detects fall significantly outside of the range of detected values, assigning them one half of the detection level would not be sufficient to accurately represent pollutant loadings and the associated cost-effectiveness of the rule.

To assess this concern and provide further transparency for this rulemaking, EPA also implemented a second method of treating non-detects where all attributed non-detects (*i.e.,* one-half of the detection limit) that exceeded the highest detected value for a particular pollutant were deleted. Since it is possible that a plant's actual loading fell outside the range of detected values of all of the plants, this methodology served to place an upper bound on the effect of non-detects on the pollutant loading and cost-effectiveness calculations. EPA's decision to incorporate this second approach for bottom ash transport water in this rulemaking reflects the exceptional circumstance in this case where there are so few detected observations in combination with wide variability in sample-specific detection values for the non-detected observations for 6 analytes. For a full discussion of the analysis method and results, see Section 10.2.2 of the TDD and Section F–4 of the RIA. EPA found that this second method of treatment of non-detects affects the averaged pollutant concentrations for 6 out of the 44 analytes, alters pollutant loadings and decreases identified TWPE loadings and removals in comparison to method 1. EPA also calculated the cost-effectiveness for the bottom ash wastestream using the averaged pollutant concentrations derived from method 2, and found in comparison to method 1 the method 2 analysis changed the cost-effectiveness value from $314/TWPE to $457/TWPE for this wastestream and cost-effectiveness of the full rule from $136/TWPE to $149/TWPE. Where appropriate in the TDD, RIA, BCA and certain other documents for the rule, EPA has reflected the results for pollutant loadings and cost effectiveness under both of these approaches. EPA's determination of BAT and the standards and rationale supporting that determination, are discussed in Section VIII; the differences in loadings and cost effectiveness associated with incorporating this second approach to addressing uncertainty related to non-detects do not alter that determination.

XVI. Regulatory Implementation

A. Implementation of the Limitations and Standards

The requirements in this rule apply to discharges from steam electric power plants through incorporation into NPDES permits issued by the EPA or authorized states under Section 402 of the Act and through local pretreatment programs under Section 307 of the Act. Permits or control mechanisms issued after this rule's effective date must incorporate the ELGs, as applicable. Also, under CWA section 510, states can require effluent limitations under state law as long as they are no less stringent than the requirements of this rule. Finally, in addition to requiring application of the technology-based ELGs in this rule, CWA section 301(b)(1)(C) requires the permitting authority to impose more stringent effluent limitations, as necessary, to meet applicable water quality standards.

1. Timing

The direct discharge limitations in this rule apply only when implemented in an NPDES permit issued to a discharger after the effective date of this rule. Under the CWA, the permitting authority must incorporate these ELGs into NPDES permits as a floor or a minimum level of control. While the rule is effective on its effective date (see **DATES** section at the beginning of this preamble), the rule allows a permitting authority to determine a date when the new effluent limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater apply to a given discharger. The permitting authority must make these final effluent limitations applicable on or after November 1, 2018. For any final effluent limitation that is specified to become applicable after November 1, 2018, the specified date must be as soon as possible, but in no case later than December 31, 2023. For dischargers in the voluntary incentives program choosing to meet effluent limitations for FGD wastewater based on use of evaporation technology, the date for meeting those limitations is December 31, 2023.

For combustion residual leachate, and for certain wastestreams (FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater) at oil-fired generating units and small generating units (50 MW or less), the final BAT limitations apply on the date that a permit is issued to a discharger, following the effective date of this rule. The rule does not build in an implementation period for meeting these limitations, as the BAT limitation on TSS is equal to the previously promulgated BPT limitation on TSS.

Pretreatment standards are self-implementing, meaning they apply directly, without the need for a permit. In this rule, the pretreatment standards for existing sources must be met by November 1, 2018.

The requirements for new source direct and indirect discharges (NSPS and PSNS) provide no extended implementation period. NSPS apply when any NPDES permit is issued to a new source direct discharger, following the effective date of this rule; PSNS apply to any new source discharging to a POTW, as of the effective date of the final rule.

Regardless of when a plant's NPDES permit is ready for renewal, the plant should immediately begin evaluating how it intends to comply with the requirements of the final ELGs. In cases where significant changes in operation are appropriate, the plant should discuss such changes with the permitting authority and evaluate appropriate steps and a timeline for the changes, even prior to the permit renewal process.

In cases where a plant's final NPDES permit will be issued after the effective date of the final ELGs, but before November 1, 2018, the permitting authority should apply limitations based on the previously promulgated BPT limitations or the plant's other applicable permit limitations until at least November 1, 2018. The permitting authority should also determine what date represents the soonest date, beginning November 1, 2018, that the plant can meet the final BAT limitations in this rule. The permit should require compliance with the final BAT limitations by that date, making clear that in no case shall the limitations apply later than December 31, 2023. Then, for permits that might be administratively continued, the final date will apply, even if that date is at the end of the implementation period. For permits that are issued on or after November 1, 2018, the permitting authority should determine the earliest possible date that the plant can meet the limitations in this rule (but in no case later than December 31, 2023), and apply the final limitations as of that date (BPT limitations or the plant's other applicable permit limitations would apply until such date).

As specified by the rule, the ''as soon as possible'' date determined by the permitting authority is November 1, 2018, unless the permitting authority determines another date after receiving information submitted by the discharger.[57] Assuming that the permitting authority receives relevant information from the discharger, in order to determine what date is ''as soon as possible'' within the implementation period, the permitting authority must then consider the following factors:

(a) Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final rule;

(b) Changes being made or planned at the plant in response to greenhouse gas regulations for new or existing fossil fuel-fired power plants under the Clean Air Act, as well as regulations for the disposal of coal combustion residuals under subtitle D of the Resource Conservation and Recovery Act;

(c) For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment; and

(d) Other factors as appropriate.

With respect to the first factor, the permitting authority should evaluate what operational changes are expected at the plant to meet the new BAT limitations for each wastestream, including the types of new treatment technologies that the plant plans to install, process changes anticipated, and the timeframe estimated to plan, design, procure, and install any relevant technologies. As specified in the second factor, the permitting authority must also consider scheduling for installation of equipment, which includes a consideration of plant changes planned or being made to comply with certain other key rules that affect the steam electric power generating industry. As specified in the third factor, for the FGD wastewater requirements only, the permitting authority must consider whether it is appropriate to allow more time for implementation, in addition to the three years before implementation of the rule begins on November 1, 2018, in order to ensure that the plant has appropriate time to optimize any relevant technologies. EPA's record demonstrates that plants installing the FGD technology basis spent several months optimizing its operation (initial commissioning period). Without allowing additional time for optimization, the plant would likely not be able to meet the limitations because they are based on the operation of optimized systems. See TDD Section 14 for additional discussion and examples regarding implementation of the final ELGs into NPDES permits.

The ''as soon as possible'' date determined by the permitting authority may or may not be different for each wastestream. EPA recommends that the permitting authority provide a well-documented justification of how it determined the ''as soon as possible'' date in the fact sheet or administrative record for the permit. If the permitting authority determines a date later than November 1, 2018, the justification should explain why allowing additional time to meet the limitations is appropriate, and why the discharger cannot meet the final effluent limitations as of November 1, 2018. In cases where the plant is already operating the BAT technology basis for a specific wastestream (*e.g.,* dry fly ash handling system), operates the majority of the BAT technology basis (*e.g.,* FGD chemical precipitation and biological treatment, without sulfide addition), or expects that relevant treatment and process changes will be in place prior to November 1, 2018, it would not generally be appropriate to allow additional time beyond that date. Regardless, in all cases, the permitting authority must make clear in the permit what date the plant must meet the limitations, and that date may be no later than December 31, 2023.

Where a discharger chooses to participate in the voluntary incentives program and be subject to effluent limitations for FGD wastewater based on evaporation, the permitting authority must allow the plant up to December 31, 2023, to meet those limitations; again, the permit must make clear that the plant must meet the final limitations by December 31, 2023.

2. Applicability of NSPS/PSNS

In 1982, EPA promulgated NSPS/PSNS for certain discharges from new sources. Those sources that were subject to the 1982 NSPS/PSNS will continue to be subject to such standards under this final rule. In addition, sources to which the 1982 NSPS/PSNS apply are also subject to the final BAT/PSES requirements in this rule because they will be existing sources with respect to such new requirements. See 40 CFR 423.15(a) and 40 CFR 423.17(a).

3. Legacy Wastewater

For purposes of the BAT limitations in this rule, legacy wastewater is FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater generated prior to the date established by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023 (see Section VIII.C.7 and Section VIII.C.8).[58] Direct discharges of legacy wastewater are, under this rule, subject to BAT effluent limitations on TSS in such wastewater, which are equal to the existing BPT effluent limitations on TSS in fly ash transport water, bottom ash transport water, and low volume waste sources.[59] See TDD Section 14 for additional information regarding the legacy wastewater BAT limitations and

[57] Even after the permitting authority receives information from the discharger, it still may be appropriate to determine that November 1, 2018, is ''as soon as possible'' for that discharger.

[58] For plants in the voluntary incentives program, legacy FGD wastewater is FGD wastewater generated prior to December 31, 2023 (see Section VIII.C.13).

[59] The final rule does not establish PSES standards for legacy wastewater for these wastestreams because TSS and the pollutants they represent are effectively treated by POTWs; and, therefore, EPA has determined that they do not pass through the POTW (see Section VIII.E).

guidance on implementing them into NPDES permits.

4. Combined Wastestreams

Most steam electric power plants combine various wastewaters (*e.g.,* FGD wastewater, fly ash and bottom ash transport water) and cooling water either before or after treatment. In such cases, to derive effluent limitations or standards at the point of discharge, the permitting authority typically combines the allowable pollutant concentrations loadings for each set of requirements to arrive at a specific limitation or standard, per pollutant, for the combined wastestream, using the building block approach or combined waste stream formula (CWF). See NPDES Permit Writer's Manual and 40 CFR 403.6. For concentration-based limitations, rather than mass-based limitations, the effluent limitation or standard for the mixed wastestream is a flow-weighted combination of the appropriate concentration–based limitations or standards for each applicable wastestream. Such a calculation is relatively straightforward if the individual wastestreams are subject to limitations or standards for the same pollutants and the flows of the wastestreams are relatively consistent. This, however, is not the case for all wastestreams at steam electric power plants.

Because EPA anticipates that permitting authorities will apply concentration-based limitations or standards, rather than mass-based limitations or standards, in NPDES permits for steam electric power plants, proper application of the building block approach or CWF is necessary to ensure that the reduced pollutant concentrations observed in a combined discharge reflect proper treatment and control strategies rather than dilution. Where a regulated wastestream is combined with a well-known dilution flow, such as cooling water, uncontaminated stormwater, or cooling tower blowdown, the concentration-based limitation for the regulated wastestream is reduced by multiplying it by a factor.[60] This factor is the total flow for the combined wastestream minus the dilution flow divided by the total flow for the combined wastestream. In some cases, a wastestream (*e.g.,* FGD wastewater) containing a regulated pollutant (*e.g.,* selenium or mercury) combines with other wastestreams that contain the same pollutant, but that are not regulated for that pollutant (*e.g.,* legacy wastewater contained in a surface impoundment). In these cases, based on the information in its record, EPA strongly recommends that in applying the building block approach or CWF to the regulated pollutant (selenium or mercury, in the example above), permitting authorities either treat the wastestream that does not have a limitation or standard for the pollutant (legacy wastewater contained in a surface impoundment, in the example above) as a dilution flow or determine a concentration for that pollutant based on representative samples of that wastestream.[61]

In all cases where the permitting authority is applying the building block approach or CWF, except where a regulated wastestream is mixed with a dilution wastestream, the permitting authority must also determine the flow rate for use in the building block approach or CWF. EPA strongly recommends that the permitting authority calculate the flow rate based on representative flow rates for each wastestream.

EPA recommends that, where a steam electric power plant chooses to combine two or more wastestreams that would call for the use of the building block approach or CWF to determine the appropriate limitations or standards for the combined wastestream, the plant should be responsible for providing sufficient data that reflect representative samples of each of the individual wastestreams that make up the combined wastestream. EPA strongly recommends that the representative samples reflect a study of each of the applicable wastestreams that covers the full range of variability in concentration and flow for each wastestream.

EPA anticipates that proper application of the building block approach or CWF will result in combined wastestream limitations and standards that will enable steam electric power plants to combine certain wastestreams, while also ensuring that the plant is actually treating its wastewater as intended by the Act and this rule, rather than simply diluting it. EPA's record demonstrates, however, that combined wastestream limitations and standards at the point of discharge, derived using the building block approach or CWF, may be impractical or infeasible for some combined wastestreams because the resulting limitation or standard for *any* of the regulated pollutants in the combined wastestream would fall below analytical detection levels. In such cases, the permitting authority should establish internal limitations on the regulated wastestream, prior to mixing of the wastestream with others, as authorized pursuant to 40 CFR 122.45(h) and 40 CFR 403.6.[62] See TDD Section 14 for more examples and details about this guidance.

5. Non-Chemical Metal Cleaning Wastes

By reserving BAT and NSPS for non-chemical metal cleaning wastes in this final rule, the permitting authority must continue to establish such requirements based on BPJ for any steam electric power plant discharging this wastestream. As explained in Section VIII.I, in permitting this wastestream, some permitting authorities have classified it as non-chemical metal cleaning wastes (a subset of metal cleaning wastes), while others have classified it as a low volume waste source; NPDES permit limitations for this wastestream thus reflect that classification. In making future BPJ BAT determinations, EPA recommends that the permitting authority examine the historical permitting record for the particular plant to determine how discharges of non-chemical metal cleaning wastes have been permitted in the past. Using historical information and its best professional judgment, the permitting authority could determine that the BPJ BAT limitations should be set equal to existing BPT limitations or it could determine that more stringent BPJ BAT limitations should apply. In making a BPJ determination for new sources, EPA recommends that the permitting authority consider whether it would be appropriate to base standards on BPT limitations for metal cleaning wastes or on a technology that achieves greater pollutant reductions.

B. Upset and Bypass Provisions

A ''bypass'' is an intentional diversion of wastestreams from any portion of a treatment facility. An ''upset'' is an exceptional incident in which there is unintentional and temporary

[60] As is the case with a single regulated wastestream, if the combined wastestream is not discharged, then the limitations and standards are not applicable.

[61] EPA does not recommend that the permitting authority assume that the pollutant is present at a significant level in the wastestream that does not have a relevant limitation or standard and just apply the same limitation or standard for the pollutant to the mixed wastestream. This will not ensure that treatment and control strategies are being employed to achieve the limitations or standards, rather than simply dilution.

[62] As described earlier for wastestreams with zero discharge limitations or standards, just because a wastestream with a numeric limitation or standard is moved, prior to discharge, for use in another plant process, that does not mean that the wastestream ceases to be subject to the applicable numeric limitation or standard, assuming that the wastestream is eventually discharged.

noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. EPA's regulations concerning bypasses and upsets for direct dischargers are set forth at 40 CFR 122.41(m) and (n) and for indirect dischargers at 40 CFR 403.16 and 403.17.

C. Variances and Modifications

The CWA requires application of effluent limitations or pretreatment standards established pursuant to CWA section 301 to all direct and indirect dischargers. The statute, however, provides for the modification of these national requirements in a limited number of circumstances. The Agency has established administrative mechanisms to provide an opportunity for relief from the application of the national effluent limitations guidelines for categories of existing sources for toxic, conventional, and nonconventional pollutants.

1. Fundamentally Different Factors Variance

EPA can develop, with the concurrence of the state, effluent limitations or standards different from the otherwise applicable requirements for an individual existing discharger if that discharger is fundamentally different with respect to factors considered in establishing the effluent limitations guidelines or standards. Such a modification is known as a Fundamentally Different Factors (FDF) variance.

EPA, in its initial implementation of the effluent guidelines program, provided for the FDF modifications in regulations, which were variances from the BPT effluent limitations, BAT limitations for toxic and nonconventional pollutants, and BCT limitations for conventional pollutants for direct dischargers. FDF variances for toxic pollutants were challenged judicially and ultimately sustained by the Supreme Court in *Chem. Mfrs. Ass'n* v. *Natural Res. Def. Council,* 470 U.S. 116, 124 (1985).

Subsequently, in the Water Quality Act of 1987, Congress added a new section to the CWA, section 301(n). This provision explicitly authorizes modifications of the otherwise applicable BAT effluent limitations, if a discharger is fundamentally different with respect to the factors specified in CWA section 304 or 403 (other than costs) from those considered by EPA in establishing the effluent limitations and standards. CWA section 301(n) also defined the conditions under which EPA can establish alternative requirements. Under Section 301(n), an application for approval of a FDF variance must be based solely on (1) information submitted during rulemaking raising the factors that are fundamentally different or (2) information the applicant did not have an opportunity to submit. The alternate limitation must be no less stringent than justified by the difference and must not result in markedly more adverse non-water quality environmental impacts than the national limitation.

EPA regulations at 40 CFR part 125, subpart D, authorizing the Regional Administrators to establish alternative limitations, further detail the substantive criteria used to evaluate FDF variance requests for direct dischargers. Thus, 40 CFR 125.31(d) identifies six factors (*e.g.,* volume of process wastewater, age and size of a discharger's facility) that can be considered in determining if a discharger is fundamentally different. The Agency must determine whether, based on one or more of these factors, the discharger in question is fundamentally different from the dischargers and factors considered by EPA in developing the nationally applicable effluent guidelines. The regulation also lists four other factors (*e.g.,* inability to install equipment within the time allowed or a discharger's ability to pay) that cannot provide a basis for an FDF variance. In addition, under 40 CFR 125.31(b) (3), a request for limitations less stringent than the national limitation can be approved only if compliance with the national limitations will result in either (a) a removal cost wholly out of proportion to the removal cost considered during development of the national limitations, or (b) a non-water quality environmental impact (including energy requirements) fundamentally more adverse than the impact considered during development of the national limits. The legislative history of CWA section 301(n) underscores the necessity for the FDF variance applicant to establish eligibility for the variance. EPA's regulations at 40 CFR 125.32(b)(1) and 40 CFR 403.13 impose this burden upon the applicant. The applicant must show that the factors relating to the discharge controlled by the applicant's permit that are claimed to be fundamentally different are, in fact, fundamentally different from those factors considered by EPA in establishing the applicable guidelines and standards. In practice, very few FDF variances have been granted for past ELGs. An FDF variance is not available to a new source subject to NSPS or PSNS. *DuPont* v. *Train,* 430 U.S. 112 (1977).

2. Economic Variances

Section 301(c) of the CWA authorizes a variance from the otherwise applicable BAT effluent guidelines for nonconventional pollutants due to economic factors. See also CWA section 301(l). The request for a variance from effluent limitations developed from BAT guidelines must normally be filed by the discharger during the public notice period for the draft permit. Other filing periods can apply, as specified in 40 CFR 122.21(m)(2). Specific guidance for this type of variance is provided in ''Draft Guidance for Application and Review of Section 301(c) Variance Requests,'' dated August 21, 1984, available on EPA's Web site at *http://www.epa.gov/npdes/pubs/OWM0469.pdf.*

3. Water Quality Variances

Section 301(g) of the CWA authorizes a variance from BAT effluent guidelines for certain nonconventional pollutants (ammonia, chlorine, color, iron, and total phenols) due to localized environmental factors. As this final rule does not establish limitations or standards for any of these pollutants, this variance is not applicable to this particular rule.

4. Removal Credits

Section 307(b)(1) of the CWA establishes a discretionary program for POTWs to grant ''removal credits'' to their indirect dischargers. Removal credits are a regulatory mechanism by which industrial users can discharge a pollutant in quantities that exceed what would otherwise be allowed under an applicable categorical pretreatment standard because it has been determined that the POTW to which the industrial user discharges consistently treats the pollutant. EPA has promulgated removal credit regulations as part of its pretreatment regulations. See 40 CFR 403.7. These regulations provide that a POTW can give removal credits if prescribed requirements are met. The POTW must apply to and receive authorization from the Approval Authority. To obtain authorization, the POTW must demonstrate consistent removal of the pollutant for which approval authority is sought. Furthermore, the POTW must have an approved pretreatment program. Finally, the POTW must demonstrate that granting removal credits will not cause the POTW to violate applicable federal, state, or local sewage sludge requirements. 40 CFR 403.7(a)(3).

The U.S. Court of Appeals for the Third Circuit interpreted the CWA as requiring EPA to promulgate the comprehensive sewage sludge regulations pursuant to CWA section 405(d)(2)(A)(ii) before any removal credits could be authorized. *See Natural Res. Def. Council* v. *EPA,* 790 F.2d 289, 292 (3d Cir. 1986), *cert. denied,* 479 U.S. 1084 (1987). Congress made this explicit in the Water Quality Act of 1987, which provided that EPA could not authorize any removal credits until it issued the sewage sludge use and disposal regulations. On February 19, 1993, EPA promulgated Standards for the Use or Disposal of Sewage Sludge, which are codified at 40 CFR part 503 (58 FR 9248). EPA interprets the Court's decision in *Natural Res. Def. Council* v. *EPA* as only allowing removal credits for a pollutant if EPA has either regulated the pollutant in part 503 or established a concentration of the pollutant in sewage sludge below which public health and the environment are protected when sewage sludge is used or disposed.

The part 503 sewage sludge regulations allow four options for sewage sludge disposal: (1) Land application for beneficial use, (2) placement on a surface disposal unit, (3) firing in a sewage sludge incinerator, and (4) disposal in a landfill which complies with the municipal solid waste landfill criteria in 40 CFR part 258. Because pollutants in sewage sludge are regulated differently depending upon the use or disposal method selected, under EPA's pretreatment regulations the availability of a removal credit for a particular pollutant is linked to the POTW's method of using or disposing of its sewage sludge. The regulations provide that removal credits can be potentially available for the following situations:

(1) If a POTW applies its sewage sludge to the land for beneficial uses, disposes of it in a surface disposal unit, or incinerates it in a sewage sludge incinerator, removal credits can be available for the pollutants for which EPA has established limits in 40 CFR part 503. EPA has set ceiling limitations for nine metals in sludge that is land applied, three metals in sludge that is placed on a surface disposal unit, and seven metals and 57 organic pollutants in sludge that is incinerated in a sewage sludge incinerator. 40 CFR 403.7(a)(3)(iv)(A).

(2) Additional removal credits can be available for sewage sludge that is land applied, placed in a surface disposal unit, or incinerated in a sewage sludge incinerator, so long as the concentration of these pollutants in sludge do not exceed concentration levels established in 40 CFR part 403, appendix G, Table II. For sewage sludge that is land applied, removal credits can be available for an additional two metals and 14 organic pollutants. For sewage sludge that is placed on a surface disposal unit, removal credits can be available for an additional seven metals and 13 organic pollutants. For sewage sludge that is incinerated in a sewage sludge incinerator, removal credits can be available for three other metals 40 CFR 403.7(a)(3)(iv)(B).

(3) When a POTW disposes of its sewage sludge in a municipal solid waste landfill that meets the criteria of 40 CFR part 258, removal credits can be available for any pollutant in the POTW's sewage sludge. 40 CFR 403.7(a)(3)(iv)(C).

D. Site-Specific Water Quality-Based Effluent Limitations

Depending on site-specific conditions and applicable state water quality standards, it may be appropriate for permitting authorities to establish water quality-based effluent limitations on bromide,[63] especially where steam electric power plants are located upstream from drinking water intakes.

Bromides (a component of TDS) are not directly controlled by the numeric effluent limitations and standards for existing sources under this final rule[64] (although they would be controlled by the NSPS/PSNS for new sources and by the BAT effluent limitations for existing sources who choose to participate in the voluntary program and are subject to the final FGD wastewater limitations based on use of evaporation technology).

Bromide discharges from coal-fired steam electric power plants can occur because bromide is naturally found in coal and is released as particulates when the coal is burned, or by the addition of bromide compounds to the coal prior to burning, or to the flue gas scrubbing process, to reduce the amount of mercury air pollution that is also created when coal is burned.

While bromide itself is not thought to be toxic at levels present in the environment, its reaction with other constituents in water may be a cause for concern now and into the future. The bromide ion in water can form brominated DBPs when drinking water plants treat the incoming source water using certain disinfection processes including chlorination and ozonation. Bromide can react with the ozone, chlorine, or chlorine-based disinfectants to form bromate and brominated and mixed chloro-bromo DBPs, such as trihalomethanes (THMs) or haloacetic acids (HAAs) (see DCN SE01920). Studies indicate that exposure to THMs and other DBPs from chlorinated water is associated with human bladder cancer (see DCN SE01981 and DCN SE01983). EPA has established the following MCLs for DBPs:

- 0.010 mg/L for bromate due to increased cancer risk from long-term exposure;
- 0.060 for HAAs due to increased cancer risk from long-term exposure; and
- 0.080 mg/L for TTHMs due to increased cancer risk and liver, kidney or central nervous system problems from long-term exposure (see DCN SE01909).

The record indicates that steam electric power plant FGD wastewater discharges occur near more than 100 public drinking water intakes on rivers and other waterbodies, and there is evidence that these discharges are already having adverse effects on the quality of drinking water sources. A 2014 study by McTigue et. al. identified four drinking water treatment plants that experienced increased levels of bromide in their source water, and corresponding increases in the formation of brominated DBPs, after the installation of wet FGD scrubbers at upstream steam electric power plants (see DCN SE04503).

Drinking water utilities are concerned as well, noting that the bromide concentrations have made it increasingly difficult for them to meet SDWA requirements for total trihalomethanes (TTHMs) (see DCN SE01949). And, bromide loadings into surface waters from coal-fired steam electric power plants could potentially increase in the future as more plant operators use bromide addition to improve the control of mercury emissions. The American Water Works Association requested that EPA ''instruct NPDES permit writers to adequately consider downstream drinking water supplies in establishing permit requirements for power plant discharges'' and take other steps to limit adverse consequences for downstream drinking water treatment plants. EPA agrees that permitting authorities should carefully consider whether water quality-based effluent limitations on bromide or TDS would be appropriate for FGD wastewater discharges from steam electric power plants upstream of drinking water intakes.

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[63] Some may establish limitations on TDS as an indicator of bromide because bromide is a component of TDS.

[64] TDS, like all pollutants, are controlled where there are zero discharge effluent limitations and standards.

EPA regulations at 40 CFR 122.44(d)(1) require that each NPDES permit shall include any requirements, in addition to or more stringent than effluent limitations guidelines or standards promulgated pursuant to sections 301, 304, 306, 307, 318 and 405 of the CWA, necessary to achieve water quality standards established under section 303 of the CWA, including state narrative criteria for water quality. Furthermore, those same regulations require that limitations must control all pollutants, or pollutant parameters (either conventional, nonconventional, or toxic pollutants) which the Director determines are or may be discharged at a level which will cause, have the reasonable potential to cause, or contribute to an excursion above any state water quality standard, including state narrative criteria for water quality.

Where the DBP problem described above may be present, water quality-based effluent limitations for steam electric power plant discharges may be required under the regulations at 40 CFR 122.44(d)(1), where necessary to meet either numeric criteria (*e.g.,* for bromide, TDS or conductivity) or narrative criteria in state water quality standards. All states have narrative water quality criteria that are designed to prevent contamination and other adverse impacts to the states' surface waters. These are often referred to as ''free from'' standards. For example, a state narrative water quality criterion for protecting drinking water sources may require discharges to protect people from adverse exposure to chemicals via drinking water. These narrative criteria may be used to develop water quality-based effluent limitations on a site-specific basis for the discharge of pollutants that impact drinking water sources, such as bromide.

To translate state narrative water quality criteria and inform the development of a water quality-based limitation for bromide, it may be appropriate for permitting authorities to use EPA's established MCLs for DBPs in drinking water because the presence of bromides in drinking water can result in exceedances of drinking water MCLs as a result of interactions during drinking water treatment and disinfection processes. The limitation would be developed for the purpose of attaining and maintaining the state's applicable narrative water quality criterion or criteria and protecting the state's designated use(s), including the protection of human health. See 40 CFR 122.44(d)(1)(vi).

For the reasons described above, during development of the NPDES permit for the steam electric power plant, the permitting authority should provide notification to any downstream drinking water treatment plants of the discharge of bromide. EPA recommends that the permitting authority collaborate with drinking water utilities and their regulators to determine what concentration of bromides at the PWS intake is needed to ensure that levels of bromate and DPBs do not exceed applicable MCLs. The maximum level of bromide in source waters at the intake that does not result in an exceedance of the MCL for DBPs is the numeric interpretation of the narrative criterion for protection of human health and may vary depending on the treatment processes employed at the drinking water treatment facility. The permitting authority would then determine the level of bromide that may be discharged from the steam electric power plant, taking into account other sources of bromide that may occur, such that the level of bromide downstream at the intake to the drinking water utility is below a level that would result in an exceedances of the applicable MCLs for DBPs. In addition, applicants for NPDES permits must, as part of their permit application, indicate whether they know or have reason to believe that conventional and/or nonconventional pollutants listed in Table IV of Appendix D to 40 CFR part 122, (which includes bromide), are discharged from each outfall. For every pollutant in Table IV of Appendix D discharged which is not limited in an applicable effluent limitations guideline, the applicant must either report quantitative data or briefly describe the reasons the pollutant is expected to be discharged as set forth in 40 CFR 122.2l(g)(7)(vi)(A), made applicable to the States at 40 CFR 123.25(a)(4).

In addition to requiring the permit applicant to provide a complete application, including proper wastewater characterization, when issuing the permit, the permitting authority can incorporate appropriate monitoring and reporting requirements, as authorized under section 402(a)(2), 33 U.S.C. 1342(a)(2), and implementing regulations at 40 CFR 122.48, 122.44(i), 122.43 and 122.41(1)(4). These requirements apply to all dischargers and include plants that have identified the presence of bromide in effluent in significant quantities and that are in proximity to downstream water treatment plants.

XVII. Related Acts of Congress, Executive Orders, and Agency Initiatives

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in Chapter 13 of the BCA Report, available in the docket.

Table XVII–1 (drawn from Table 13–1 of the BCA Report) provides the results of the benefit-cost analysis with both costs and benefits annualized over 24 years and discounted using a three percent discount rate.

TABLE XVII–1—TOTAL MONETIZED ANNUALIZED BENEFITS AND COSTS OF THE FINAL BAT AND PSES

[Millions, 2013$, three percent discount rate] [a]

	Total social costs [b]	Total monetized benefits
Annualized Value	$479.5	$450.6 to $565.6

[a] All costs and benefits were annualized over 24 years and using a three percent discount rate.
[b] Total social costs include compliance costs to facilities.

B. Paperwork Reduction Act

OMB has previously approved the information collection requirements contained in the existing regulations 40 CFR part 423 under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2040–0281. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

EPA estimated small changes in monitoring costs at steam electric power plants for metals in the final rule; EPA accounted for these costs as part of its analysis of the economic impacts. Plants, however, will also realize certain savings by no longer monitoring effluent that would cease to exist under the final rule. The net changes in monitoring and reporting are expected to be minimal, and EPA determined that the existing burden estimates appropriately reflect any final rule burden associated with monitoring.

Based on the information in its record, EPA does not expect the final rule to increase costs to permitting authorities. The rule will not change permit application requirements or the associated review; it will not increase the number of permits issued to steam electric power plants; nor does it increase the efforts involved in developing or reviewing such permits. In fact, the final rule will reduce the burden to permitting authorities. In the absence of nationally applicable BAT requirements, as appropriate, permitting authorities must establish technology-based effluent limitations using BPJ to establish site-specific requirements based on information submitted by the discharger. Permitting authorities that establish technology-based effluent limitations on a BPJ basis often spend significant time, effort, and resources doing so, and dischargers may expend significant resources providing associated data and information. Establishing nationally applicable BAT requirements that eliminate the need to develop BPJ-based limitations makes permitting easier and less costly in this respect.

As explained in Section XVI.A, under this rule, after the permitting authority receives information from the discharger, it must determine, on a facility-specific basis, what date is ''as soon as possible'' during the period beginning November 1, 2018, and ending December 31, 2023. This one-time burden to the discharger and the permitting authority, however, is no more excessive than the existing burden associated with developing technology-based effluent limitations on a BPJ basis; in fact, it is very likely less burdensome. Nevertheless, EPA conservatively estimated no net change (increase or decrease) in the cost burden to federal or state governments or dischargers associated with this final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice-and-comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The basis for this finding is documented in Chapter 8 of the RIA included in the docket and summarized below. EPA estimates that 243 to 507 entities own steam electric power plants to which the ELGs apply, of which 110 to 191 entities are small (see Table XVII–2).

TABLE XVII–2—NUMBER OF ENTITIES OWNING STEAM ELECTRIC POWER PLANTS BY SECTOR AND SIZE

[Assuming two different ownership cases] [a]

Ownership type	Lower bound estimate of number of entities owning steam electric power plants [b]			Upper bound estimate of number of entities owning steam electric power plants [b]		
	Total	Small [c]	% Small	Total	Small [c]	% Small
Investor-Owned Utilities	97	28	28.9	244	66	27.1
Nonutilities	36	19	52.8	77	35	46.1
Cooperatives	29	26	89.7	49	46	93.9
Municipality	65	36	55.4	101	43	42.1
Other Political Subdivision	12	1	8.3	30	1	3.3
Federal	0	0	N/A	0	0	N/A
State	2	0	0.0	2	0	0.0
Tribal	0	0	N/A	0	0	N/A
All Entity Types	243	110	45.3	507	191	37.6

[a] In 19 instances, a plant is owned by a joint venture of two entities; in one instance, the plant is owned by a joint venture of three entities.
[b] Of these, 75 entities, 21 of which are small, own steam electric power plants that are expected to incur compliance costs under the final rule under both Case 1 and Case 2.
[c] EPA was unable to determine size for 16 parent entities; for this analysis, these entities are assumed to be small.

To assess whether small entities' compliance costs might constitute a significant impact, EPA summed annualized compliance costs for the steam electric power plants determined to be owned by a given small entity and calculated these costs as a percentage of entity revenue (cost-to-revenue test). EPA compared the resulting percentages to impact criteria of one percent and three percent of revenue. Small entities estimated to incur compliance costs exceeding one or more of the one percent and three percent impact thresholds were identified as potentially incurring a significant impact.

EPA notes that setting the BAT limitations for FGD wastewater, fly ash transport water, bottom ash transport water, FGMC wastewater, and gasification wastewater equal to the BPT limitations on TSS in fly ash transport water, bottom ash transport water, and low volume waste sources at existing generating units with a total nameplate generating capacity of 50 MW or less (as discussed in Section VIII.C.12) reduces the potential impacts of the rule on small entities and municipalities. The rulemaking record indicates that establishing a size threshold of 50 MW or less preferentially minimizes some of the expected economic impacts on municipalities and small entities.

Table XVII–3 presents the estimated numbers of small entities incurring costs exceeding one percent and three percent of revenue, by ownership type.

TABLE XVII–3—ESTIMATED COST-TO-REVENUE IMPACT ON SMALL ENTITIES OWNING STEAM ELECTRIC POWER PLANTS, BY OWNERSHIP TYPE

	Lower bound estimate of number of entities owning steam electric power plants				Upper bound estimate of number of entities owning steam electric power plants			
	Cost ≥1% of revenue		Cost ≥3% of revenue		Cost ≥1% of revenue		Cost ≥3% of revenue	
	Number of small entities	% of small affected entities [b]	Number of small entities [a]	% of small affected entities [b]	Number of small entities	% of small affected entities [b]	Number of small entities [a]	% of small affected entities [b]
Ownership Type	Out of total 110 small entities				Out of total 191 small entities			
Cooperative	1	3.8	0	0.0	1	2.2	0	0.0
Investor-Owned	0	0.0	0	0.0	0	0.0	0	0.0
Municipality	4	11.1	1	2.8	4	9.4	1	2.3
Nonutility	1	5.3	0	0.0	1	2.8	0	0.0
Other Political Subdivision	0	0.0	0	0.0	0	0.0	0	0.0
Total	6	5.5	1	0.9	6	3.1	1	0.5

[a] The number of entities with cost-to-revenue ratios exceeding three percent is a subset of the number of entities with such ratios exceeding one percent.

[b] Percentage values were calculated relative to the total of 110 (Case 1) and 191 (Case 2) small entities owning steam electric power plants. EPA expects that Case 2 is a more likely ownership scenario for small entities (*e.g.,* small municipalities) as small entities may be less likely to own multiple non-surveyed steam electric power plants. See RIA Chapter 8 for details.

As reported in Table XVII–3, EPA estimates that six small entities owning steam electric power plants (one cooperative, one nonutility, and four municipalities) will incur costs exceeding one percent of revenue as a result of the final rule, and one small municipality owning steam electric power plants will incur costs exceeding three percent of revenue. The numbers of small entities incurring costs exceeding either the one or three percent of revenue impact threshold are small in the absolute and represent small percentages of the total estimated number of small entities, which supports EPA's finding of no significant impact on a substantial number of small entities (No SISNOSE).

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. This action contains a federal mandate that may result in expenditures of $100 million or more (annually, adjusted for inflation) for state, local, and tribal governments, in the aggregate, or the private sector in any one year ($141 million in 2013). Accordingly, EPA prepared a written statement required under section 202 of UMRA. The statement is included in the docket for this action (see Chapter 9 in the RIA report) and briefly summarized here.

Consistent with the intergovernmental consultation provisions of UMRA section 204, EPA consulted with governmental entities affected by this rule. EPA described the government-to-government dialogue leading to the proposed rule in its preamble to the proposed rulemaking. EPA received comments from state and local government representatives in response to the proposed rule and considered this input in developing the final rule.

Consistent with UMRA section 205, EPA identified and analyzed a reasonable number of regulatory alternatives to determine BAT/BADCT. Section VIII of this preamble describes the options.

This action is not subject to the requirements of UMRA section 203 because it contains no regulatory requirements that might significantly or uniquely affect small governments. For its assessment of the impact of compliance requirements on small governments (governments for populations of less than 50,000), EPA compared total costs and costs per plant estimated to be incurred by small governments with the costs estimated to be incurred by large governments. EPA also compared costs for small government-owned plants with those of non-government-owned facilities. The Agency evaluated both the average and maximum annualized cost per plant. Chapter 9 of the RIA report provides details of these analyses. In all of these comparisons, both for the cost totals and, in particular, for the average and maximum cost per plant, the costs for small government-owned facilities were less than those for large government-owned facilities and for small non-government-owned facilities. On this basis, EPA concluded that the final rule does not significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

Under Executive Order (E.O.) 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments or EPA consults with state and local officials early in the process of developing the action.

This action has federalism implications because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs.

EPA anticipates that this final rule will not impose incremental administrative burden on states from issuing, reviewing, and overseeing compliance with discharge requirements. However, EPA has identified 168 steam electric power plants owned by state or local government entities, out of which 16 plants are estimated to incur costs to meet the limitations. EPA estimates that the maximum aggregate compliance cost in any one year to governments (excluding the federal government) is $171.4 million (see Chapter 9 of the RIA report for details). Based on this information, this action may impose substantial direct compliance costs on state or local governments. Accordingly, EPA provides the following federalism summary impact statement as required by section 6(b) of E.O. 13132.

EPA consulted with elected state and local officials or their representative national organizations early in the process of developing the rule to ensure their meaningful and timely input into its development. The preamble to the proposed rule described these consultations, which included a briefing on October 11, 2011, attended by representatives from the National League of Cities, the National Conference of State Legislatures, the National Association of Counties, the National Association of Towns and Townships, the U.S. Conference of Mayors, the Council of State Governments, the County Executives of America, and the Environmental Council of the States. Policy and professional groups such as the National Rural Electric Cooperative Association, America's Clean Water Agencies, and the American Public Power Association also participated in the briefing, as did environmental and natural resource policy staff representing nine state agencies and approximately 25 local governments and/or utilities. The participants asked questions and raised comments during the meeting. In response to the Agency's request for pre-proposal written submittals within eight weeks of the briefing, EPA received separate written submittals regarding the technology options, pollutant removal effectiveness, costs of specific technologies and overall costs, impacts on small generating units and on small governments, among others. EPA carefully considered these comments in developing the proposed rule.

EPA received comment on the proposed ELGs from 31 state and local officials or their representatives. Some state and local officials expressed concerns EPA had underestimated the costs and overstated the pollutant removals of the technology options. They stated that the ELGs would impose significant costs on small entities, and would result in electricity rate increases that are unaffordable for households. They also stated that small municipal systems typically operate smaller units with disproportionally greater compliance costs as compared to larger units. Commenters also expressed concern about coordination of the CCR and ELG rules, the potential premature retirement of coal-fired units with limited remaining life, and potential downtime during retrofits. Finally, some commenters asked that EPA allow more time to phase-in the requirements. Other state and local officials supported revisions of the ELGs and generally opposed reliance on BPJ as a basis for establishing limitations for FGD wastewater. EPA considered these comments in developing the final rule. A list of the state and local government commenters has been provided to OMB and has been placed in the docket for this rulemaking. In addition, the detailed response to comments from these entities is contained in EPA's response to comments document on this final rulemaking, which has also been placed in the docket for this rulemaking.

As explained in Section VIII, the final rule establishes different BAT/PSES requirements for oil-fired generating units and units of 50 MW or less. These different requirements alleviate some of the concerns raised by state and local government representatives by reducing the number of government entities incurring costs to meet the ELG requirements. The implementation schedule described in Section XVI gives time to facilities to make changes to their operations to meet the final effluent limitations. Moreover, the rule does not rely on BPJ determinations for establishment of FGD wastewater limitations or standards. Finally, as explained in Section IX, EPA's analysis demonstrates that the requirements are economically achievable for the steam electric industry as a whole, including plants owned by state or local government entities.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in E.O. 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in E.O. 13175. EPA's analyses show that tribal governments do not own any facility to which the ELGs apply. Thus, E.O. 13175 does not apply to this action.

Although E.O. 13175 does not apply to this action, EPA consulted with federally recognized tribal officials under EPA's Policy on Consultation and Coordination with Indian tribes early in the process of developing this rule to enable them to have meaningful and timely input into its development. EPA initiated consultation and coordination with federally recognized tribal governments in August 2011. EPA shared information about the steam electric effluent guidelines rulemaking in discussions with the National Tribal Caucus and the National Tribal Water Council. EPA continued this government-to-government dialogue by mailing a consultation notification letter to tribal leaders, and on March 28, 2012, held a tribal consultation conference call with tribal representatives about the rulemaking process and objectives, with a focus on identifying specific ways that the rulemaking may affect tribes. Representatives from one tribe provided input to the rule. EPA considered input from tribal representatives in developing this final rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to E.O. 13045 (62 FR 19885, April 23, 1997) because the EPA does not expect that the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This action's health and risk assessments are contained in Chapter 3 of the BCA Report and summarized below.

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

This analysis considered several measures of children's health benefits associated with lead exposure for children up to age six. Avoided neurological and cognitive damages were expressed as changes in three metrics: (1) Overall IQ levels; (2) the incidence of low IQ scores (<70); and (3) the incidence of levels of lead in the blood above 20 mg/dL.

EPA estimated the IQ-related benefits associated with reduced in utero mercury exposure from maternal fish consumption in exposed populations. Among approximately 418,953 babies born per year who are potentially exposed to discharges of mercury from steam electric power plants, the final rule reduces total IQ point losses over the period of 2019 through 2042 by about 7,219 points. The monetary benefits associated with the avoided IQ point losses are $3.5 million per year (mean estimate, at three percent discount rate).

EPA's analysis also shows annualized benefits to children from reduced lead discharges of approximately $1.0 million (at three percent discount rate).

EPA identified additional benefits to children, such as reduced exposure to lead and the resultant neurological and cognitive damages in children over the age of seven, as well as other adverse health effects.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action,'' as defined by E.O. 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

The Agency analyzed the potential energy effects of these ELGs. The potentially significant effects of this rule on energy supply, distribution, or use concern the electric power sector. EPA found that the final rule will not cause effects in the electric power sector that constitute a significant adverse effect under E.O. 13211. Namely, the Agency found that this rule does not reduce electricity production in excess of 1 billion kilowatt hours per year or in excess of 500 megawatts of installed capacity, and therefore does not constitute a significant regulatory action under E.O. 13211.

For more detail on the potential energy effects of this final rule, see Chapter 10 in the RIA report.

I. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

E.O. 12898 (59 FR 7629, Feb. 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S.

EPA determined that the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations. The results of this evaluation are contained in Chapter 14 of the BCA Report, available in the docket.

To meet the objectives of E.O. 12898, EPA examined whether the rule creates potential environmental justice concerns in the areas affected by steam electric power plant discharges. The Agency analyzed the demographic characteristics of the populations who live in proximity to steam electric power plants and who may be exposed to pollutants in steam electric power plant discharges (populations who consume recreationally caught fish from affected reaches) to determine whether minority and or low-income populations are subject to disproportionally high environmental impacts.

EPA conducted the analysis in two ways. First, EPA compared demographic data for populations living in proximity to steam electric power plants to demographic characteristics at the state and national levels. This analysis focuses on the spatial distribution of minority and low-income groups to determine whether these groups are more or less represented in the populations that are expected to benefit from the final rule, based on their proximity to steam electric power plants. This analysis shows that approximately 450,000 people reside within one mile of a steam electric power plant currently discharging to surface waters and 2.7 million people reside within three miles. A greater fraction of the populations living in such proximity to the plants has income below the poverty threshold (16.4 and 15.3 percent, respectively for populations within one and three miles) than the national average (13.9 percent).

Second, EPA conducted analyses of populations exposed to steam electric power plant discharges through consumption of recreationally caught fish by estimating exposure and health effects by demographic cohort. Where possible, EPA used analytic assumptions specific to the demographic cohorts—*e.g.,* fish consumption rates specific to different racial groups. The results show that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because, in fact, it increases the level of environmental protection (reduces adverse human health and environmental effects) for all affected populations, including minority and low-income populations. Furthermore, EPA estimated that minority and low-income populations will receive, proportionately, more of the human health benefits associated with the final rule.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

Appendix A to the Preamble: Definitions, Acronyms, and Abbreviations Used in This Preamble

The following acronyms and abbreviations are used in this preamble.

Administrator. The Administrator of the U.S. Environmental Protection Agency.

Agency. U.S. Environmental Protection Agency.

BAT. Best available technology economically achievable, as defined by CWA sections 301(b)(2)(A) and 304(b)(2)(B).

BCT. The best conventional pollutant control technology applicable to discharges of conventional pollutants from existing industrial point sources, as defined by sections 301(b)(2)(E) and 304(b)(4) of the CWA.

Bioaccumulation. General term describing a process by which chemicals are taken up by an organism either directly from exposure to a contaminated medium or by consumption of food containing the chemical, resulting in a net accumulation of the chemical by an organism due to uptake from all routes of exposure.

BMP. Best management practice.

Bottom ash. The ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls. Economizer ash is included when it is collected with bottom ash.

BPT. The best practicable control technology currently available as defined by sections 301(b)(1) and 304(b)(1) of the CWA.

CBI. Confidential Business Information.

CCR. Coal Combustion Residuals.

Clean Water Act (CWA). The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 *et seq.*), as amended, *e.g.,* by the Clean Water Act of 1977 (Pub. L. 95–217), and the Water Quality Act of 1987 (Pub. L. 100–4).

Combustion residuals. Solid wastes associated with combustion-related power plant processes, including fly and bottom ash from coal-, petroleum coke-, or oil-fired units; FGD solids; FGMC wastes; and other wastewater treatment solids associated with combustion wastewater. In addition to the residuals that are associated with coal combustion, this also includes residuals associated with the combustion of other fossil fuels.

Combustion residual leachate. Leachate from landfills or surface impoundments containing combustion residuals. Leachate is composed of liquid, including any suspended or dissolved constituents in the liquid, that has percolated through waste or other materials emplaced in a landfill, or that passes through the surface impoundment's containment structure (*e.g.,* bottom, dikes, and berms). Combustion residual leachate includes seepage and/or leakage from a combustion residual landfill or impoundment unit. Combustion residual leachate includes wastewater from landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility.

Direct discharge. (a) Any addition of any ''pollutant'' or combination of pollutants to ''waters of the United States'' from any ''point source,'' or (b) any addition of any pollutant or combination of pollutant to waters of the ''contiguous zone'' or the ocean from any point source other than a vessel or other floating craft which is being used as a means of transportation. This definition includes additions of pollutants into waters of the United States from: Surface runoff which is collected or channeled by man; discharges though pipes, sewers, or other conveyances owned by a State, municipality, or other person which do not lead to a treatment works; and discharges through pipes, sewers, or other conveyances, leading into privately owned treatment works. This term does not include an addition of pollutants by any ''indirect discharger.''

Direct discharger. A facility that discharges treated or untreated wastewaters into waters of the U.S.

DOE. Department of Energy.

Dry bottom ash handling system. A system that does not use water as the transport medium to convey bottom ash away from the boiler. It includes systems that collect and convey the ash without any use of water, as well as systems in which bottom ash is quenched in a water bath and then mechanically or pneumatically conveyed away from the boiler. Dry bottom ash handling systems do not include wet sluicing systems (such as remote MDS or complete recycle systems).

Dry fly ash handling system. A system that does not use water as the transport medium to convey fly ash away from particulate collection equipment.

Effluent limitation. Under CWA section 502(11), any restriction, including schedules of compliance, established by a state or the Administrator on quantities, rates, and concentrations of chemical, physical, biological, and other constituents which are discharged from point sources into navigable waters, the waters of the contiguous zone, or the ocean, including schedules of compliance.

EIA. Energy Information Administration.

ELGs. Effluent limitations guidelines and standards.

EO. Executive Order.

EPA. U.S. Environmental Protection Agency.

ESP. Electrostatic precipitator.

Facility. Any NPDES ''point source'' or any other facility or activity (including land or appurtenances thereto) that is subject to regulation under the NPDES program.

FGD. Flue gas desulfurization.

FGD Wastewater. Wastewater generated specifically from the wet flue gas desulfurization scrubber system that comes into contact with the flue gas or the FGD solids, including but not limited to, the blowdown or purge from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater.

FGD gypsum. Gypsum generated specifically from the wet FGD scrubber system, including any solids separation or solids dewatering processes.

FGMC. Flue gas mercury control.

FGMC System. An air pollution control system installed or operated for the purpose of removing mercury from flue gas.

Flue Gas Mercury Control Wastewater. Wastewater generated from an air pollution control system installed or operated for the purpose of removing mercury from flue gas. This includes fly ash collection systems when the particulate control system follows sorbent injection or other controls to remove mercury from flue gas. FGD wastewater generated at plants using oxidizing agents to remove mercury in the FGD system and not in a separate FGMC system is not included in this definition.

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

Gasification Wastewater. Any wastewater generated at an integrated gasification combined cycle operation from the gasifier or the syngas cleaning, combustion, and cooling processes. Gasification wastewater includes, but is not limited to the following: Sour/grey water; CO_2/steam stripper wastewater; sulfur recovery unit blowdown, and wastewater resulting from slag handling or fly ash handling, particulate removal, halogen removal, or trace organic removal. Air separation unit blowdown, noncontact cooling water, and runoff from fuel and/or byproduct piles are not considered gasification wastewater. Wastewater that is collected intermittently in floor drains in the gasification process areas from leaks, spills and cleaning occurring during normal operation of the gasification operation is not considered gasification wastewater.

Ground water. Water that is found in the saturated part of the ground underneath the land surface.

IGCC. Integrated gasification combined cycle.

Indirect discharge. Wastewater discharged or otherwise introduced to a POTW.

IPM. Integrated Planning Model.

Landfill. A disposal facility or part of a facility where solid waste, sludges, or other process residuals are placed in or on any natural or manmade formation in the earth for disposal and which is not a storage pile, a land treatment facility, a surface impoundment, an underground injection well, a salt dome or salt bed formation, an underground mine, a cave, or a corrective action management unit.

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

MDS. Mechanical drag system.

Mechanical drag system. Bottom ash handling system that collects bottom ash from the bottom of the boiler in a water-filled trough. The water bath in the trough quenches the hot bottom ash as it falls from the boiler and seals the boiler gases. A drag chain operates in a continuous loop to drag bottom ash from the water trough up an incline, which dewaters the bottom ash by gravity, draining the water back to the trough as the bottom ash moves upward. The dewatered bottom ash is often conveyed to a nearby collection area, such as a small bunker outside the boiler building, from which it is loaded onto trucks and either sold or transported to a landfill. The MDS is considered a dry bottom ash handling system because the ash transport mechanism is mechanical removal by the drag chain, not the water.

Metal cleaning wastes. Any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.

Mortality. Death rate or proportion of deaths in a population.

NAICS. North American Industry Classification System.

NPDES. National Pollutant Discharge Elimination System.

NSPS. New Source Performance Standards.

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

ORCR. Office of Resource Conservation and Recovery.

Point source. Any discernable, confined, and discrete conveyance, including but not limited to, any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft from which pollutants are or may be discharged. The term does not include agricultural stormwater discharges or return flows from irrigated agriculture. See CWA section 502(14), 33 U.S.C. 1362(14); 40 CFR 122.2.

POTW. Publicly owned treatment works. See CWA section 212, 33 U.S.C. 1292; 40 CFR 122.2, 403.3

Primary particulate collection system. The first place in the process where fly ash is collected, such as collection at an ESP or baghouse. For example, a coal combustion particulate collection system may include multiple steps including a primary particulate collection step such as ESP followed by other processes such as a fabric filter which would constitute a secondary particulate collection system.

PSES. Pretreatment Standards for Existing Sources.

PSNS. Pretreatment Standards for New Sources.

Publicly Owned Treatment Works. Any device or system, owned by a state or municipality, used in the treatment (including recycling and reclamation) of municipal sewage or industrial wastes of a liquid nature that is owned by a state or municipality. This includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment. See CWA section 212, 33 U.S.C. 1292; 40 CFR 122.2, 403.3.

RCRA. The Resource Conservation and Recovery Act of 1976, 42 U.S.C. 6901 *et seq.*

Remote MDS. Bottom ash handling system that collects bottom ash at the bottom of the boiler, then uses transport water to sluice the ash to a remote MDS that dewaters bottom ash using a similar configuration as the MDS. The remote MDS is considered a wet bottom ash handling system because the ash transport mechanism is water.

RFA. Regulatory Flexibility Act.

SBA. Small Business Administration.

Sediment. Particulate matter lying below water.

Steam electric power plant wastewater. Wastewaters associated with or resulting from the combustion process, including ash transport water from coal-, petroleum coke-, or oil-fired units; air pollution control wastewater (*e.g.,* FGD wastewater, FGMC wastewater, carbon capture wastewater); and leachate from landfills or surface impoundments containing combustion residuals.

Surface water. All waters of the United States, including rivers, streams, lakes, reservoirs, and seas.

Toxic pollutants. As identified under the CWA, 65 pollutants and classes of pollutants, of which 126 specific substances have been designated priority toxic pollutants. See appendix A to 40 CFR part 423.

Transport water. Wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (*e.g.,* leaks from valve packing, pipe flanges, or piping) or minor maintenance events (*e.g.,* replacement of valves or pipe sections).

UMRA. Unfunded Mandates Reform Act.

Wet bottom ash handling system. A system in which bottom ash is conveyed away from the boiler using water as a transport medium. Wet bottom ash systems typically send the ash slurry to dewatering bins or a surface impoundment. Wet bottom ash handling systems include systems that operate in conjunction with a traditional wet sluicing system to recycle all bottom ash transport water (remote MDS or complete recycle system).

Wet FGD system. Wet FGD systems capture sulfur dioxide from the flue gas using a sorbent that has mixed with water to form a wet slurry, and that generates a water stream that exits the FGD scrubber absorber.

Wet fly ash handling system. A system that conveys fly ash away from particulate removal equipment using water as a transport medium. Wet fly ash systems typically dispose of the ash slurry in a surface impoundment.

List of Subjects in 40 CFR Part 423

Environmental protection, Electric power generation, Power plants, Waste treatment and disposal, Water pollution control.

Dated: September 30, 2015.

Gina McCarthy,

Administrator.

Therefore, 40 CFR Chapter I is amended as follows:

PART 423—STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

■ 1. The authority citation for part 423 is revised to read as follows:

Authority: Secs. 101; 301; 304(b), (c), (e), and (g); 306; 307; 308 and 501, Clean Water Act (Federal Water Pollution Control Act Amendments of 1972, as amended; 33 U.S.C. 1251; 1311; 1314(b), (c), (e), and (g); 1316; 1317; 1318 and 1361).

■ 2. Section 423.10 is revised as follows:

§ 423.10 Applicability.

The provisions of this part apply to discharges resulting from the operation of a generating unit by an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (*e.g.,* petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium. This part applies to discharges associated with both the combustion turbine and steam turbine portions of a combined cycle generating unit.

■ 3. Section 423.11 is amended by:

■ a. Revising paragraphs (b), (e), and (f).

■ b. Adding paragraphs (n) through (t).

The revisions and additions read as follows:

§ 423.11 Specialized definitions.

* * * * *

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

* * * * *

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

(f) The term bottom ash means the ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls. Economizer ash is included in this definition when it is collected with bottom ash.

* * * * *

(n) The term flue gas desulfurization (FGD) wastewater means any wastewater generated specifically from the wet flue gas desulfurization scrubber system that comes into contact with the flue gas or the FGD solids, including but not limited to, the blowdown from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater.

(o) The term flue gas mercury control wastewater means any wastewater generated from an air pollution control system installed or operated for the purpose of removing mercury from flue gas. This includes fly ash collection systems when the particulate control system follows sorbent injection or other controls to remove mercury from flue gas. FGD wastewater generated at plants using oxidizing agents to remove mercury in the FGD system and not in a separate FGMC system is not included in this definition.

(p) The term transport water means any wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (*e.g.,* leaks from valve packing, pipe flanges, or piping) or minor maintenance events (*e.g.,* replacement of valves or pipe sections).

(q) The term gasification wastewater means any wastewater generated at an integrated gasification combined cycle operation from the gasifier or the syngas cleaning, combustion, and cooling processes. Gasification wastewater includes, but is not limited to the following: Sour/grey water; CO_2/steam stripper wastewater; sulfur recovery unit blowdown, and wastewater resulting from slag handling or fly ash handling, particulate removal, halogen removal, or trace organic removal. Air separation unit blowdown, noncontact cooling water, and runoff from fuel and/or byproduct piles are not considered gasification wastewater. Wastewater that is collected intermittently in floor drains in the gasification process area from leaks, spills, and cleaning occurring during normal operation of the gasification operation is not considered gasification wastewater.

(r) The term combustion residual leachate means leachate from landfills or surface impoundments containing combustion residuals. Leachate is composed of liquid, including any suspended or dissolved constituents in the liquid, that has percolated through waste or other materials emplaced in a landfill, or that passes through the surface impoundment's containment structure (*e.g.,* bottom, dikes, berms). Combustion residual leachate includes seepage and/or leakage from a combustion residual landfill or impoundment unit. Combustion residual leachate includes wastewater from landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility.

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

(t) The phrase ''as soon as possible'' means November 1, 2018, unless the permitting authority establishes a later date, after receiving information from the discharger, which reflects a consideration of the following factors:

(1) Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of this part.

(2) Changes being made or planned at the plant in response to:

(i) New source performance standards for greenhouse gases from new fossil fuel-fired electric generating units, under sections 111, 301, 302, and 307(d)(1)(C) of the Clean Air Act, as amended, 42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C);

(ii) Emission guidelines for greenhouse gases from existing fossil fuel-fired electric generating units, under sections 111, 301, 302, and 307(d) of the Clean Air Act, as amended, 42 U.S.C. 7411, 7601, 7602, 7607(d); or

(iii) Regulations that address the disposal of coal combustion residuals as solid waste, under sections 1006(b), 1008(a), 2002(a), 3001, 4004, and 4005(a) of the Solid Waste Disposal Act of 1970, as amended by the Resource Conservation and Recovery Act of 1976, as amended by the Hazardous and Solid Waste Amendments of 1984, 42 U.S.C. 6906(b), 6907(a), 6912(a), 6944, and 6945(a).

(3) For FGD wastewater requirements only, an initial commissioning period for the treatment system to optimize the installed equipment.

■ (4) Other factors as appropriate.

■ 4. Section 423.12 is amended by:

■ a. Revising paragraphs (b)(11) and (12).

■ b. Adding paragraph (b)(13).

The revisions and addition read as follows:

§ 423.12 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).

* * * * *

(b) * * *

(11) The quantity of pollutants discharged in FGD wastewater, flue gas mercury control wastewater, combustion residual leachate, or gasification wastewater shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration listed in the following table:

Pollutant or pollutant property	BPT Effluent limitations	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

(12) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of the mass-based limitations specified in paragraphs (b)(3) through (b)(7), and (b)(11), of this section. Concentration limitations shall be those concentrations specified in this section.

(13) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b)(1) through (b)(12) of this section attributable to each controlled waste source shall not exceed the specified limitations for that waste source.

■ 5. Section 423.13 is amended by:

■ a. Revising paragraphs (g) and (h).

■ b. Adding paragraphs (i) through (n).

The revisions and additions read as follows:

§ 423.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

* * * * *

(g)(1)(i) *FGD wastewater.* Except for those discharges to which paragraph (g)(2) or (g)(3) of this section applies, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table following this paragraph (g)(1)(i). Dischargers must meet the effluent limitations for FGD wastewater in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023. These effluent limitations apply to the discharge of FGD wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph.

Pollutant or pollutant property	BAT Effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	11	8
Mercury, total (ng/L)	788	356
Selenium, total (ug/L)	23	12
Nitrate/nitrite as N (mg/L)	17.0	4.4

(ii) For FGD wastewater generated before the date determined by the permitting authority, as specified in paragraph (g)(1)(i), the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed for TSS in § 423.12(b)(11).

(2) For any electric generating unit with a total nameplate capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed for TSS in § 423.12(b)(11).

(3)(i) For dischargers who voluntarily choose to meet the effluent limitations for FGD wastewater in this paragraph, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table following this paragraph (g)(3)(i). Dischargers who choose to meet the effluent limitations for FGD wastewater in this paragraph must meet such limitations by December 31, 2023. These effluent limitations apply to the discharge of FGD wastewater generated on and after December 31, 2023.

Pollutant or pollutant property	BAT Effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	4	
Mercury, total (ng/L)	39	24
Selenium, total (ug/L)	5	
TDS (mg/L)	50	24

(ii) For discharges of FGD wastewater generated before December 31, 2023, the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed for TSS in § 423.12(b)(11).

(h)(1)(i) *Fly ash transport water.* Except for those discharges to which paragraph (h)(2) of this section applies, or when the fly ash transport water is used in the FGD scrubber, there shall be no discharge of pollutants in fly ash transport water. Dischargers must meet the discharge limitation in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023. This limitation applies to the discharge of fly ash transport water generated on and after the date determined by the permitting authority for meeting the discharge limitation, as specified in this paragraph. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant (except when it is used in the FGD scrubber), the resulting effluent must comply with the discharge limitation in this paragraph. When the fly ash transport water is used in the FGD scrubber, the quantity of pollutants in fly ash transport water shall not exceed the quantity determined by multiplying the flow of fly ash transport water times the concentration listed in the table in paragraph (g)(1)(i) of this section.

(ii) For discharges of fly ash transport water generated before the date determined by the permitting authority, as specified in paragraph (h)(1)(i) of this section, the quantity of pollutants discharged in fly ash transport water shall not exceed the quantity determined by multiplying the flow of fly ash transport water times the concentration listed for TSS in § 423.12(b)(4).

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in fly ash transport water shall not exceed the quantity determined by multiplying the flow of fly ash transport water times the concentration listed for TSS in § 423.12(b)(4).

(i)(1)(i) *Flue gas mercury control wastewater.* Except for those discharges to which paragraph (i)(2) of this section applies, there shall be no discharge of pollutants in flue gas mercury control wastewater. Dischargers must meet the discharge limitation in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023. This limitation applies to the discharge of flue gas mercury control wastewater generated on and after the date determined by the permitting authority for meeting the discharge limitation, as specified in this paragraph. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge limitation in this paragraph.

(ii) For discharges of flue gas mercury control wastewater generated before the date determined by the permitting authority, as specified in paragraph (i)(1)(i) of this section, the quantity of pollutants discharged in flue gas mercury control wastewater shall not exceed the quantity determined by multiplying the flow of flue gas mercury control wastewater times the concentration for TSS listed in § 423.12(b)(11).

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in flue gas mercury control wastewater shall not exceed the quantity determined by multiplying the flow of flue gas mercury control wastewater times the concentration for TSS listed in § 423.12(b)(11).

(j)(1)(i) *Gasification wastewater.* Except for those discharges to which paragraph (j)(2) of this section applies, the quantity of pollutants in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the table following this paragraph (j)(1)(i). Dischargers must meet the effluent limitations in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023. These effluent limitations apply to the discharge of gasification wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph.

Pollutant or pollutant property	BAT Effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	4	
Mercury, total (ng/L)	1.8	1.3
Selenium, total (ug/L)	453	227
Total dissolved solids (mg/L)	38	22

(ii) For discharges of gasification wastewater generated before the date determined by the permitting authority, as specified in paragraph (j)(1)(i) of this section, the quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration for TSS listed in § 423.12(b)(11).

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed for TSS in § 423.12(b)(11).

(k)(1)(i) *Bottom ash transport water.* Except for those discharges to which paragraph (k)(2) of this section applies, or when the bottom ash transport water is used in the FGD scrubber, there shall be no discharge of pollutants in bottom ash transport water. Dischargers must meet the discharge limitation in this paragraph by a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023. This limitation applies to the discharge of bottom ash transport water generated on and after the date determined by the permitting authority for meeting the discharge limitation, as specified in this paragraph. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant (except when it is used in the FGD scrubber), the resulting effluent must comply with the discharge limitation in this paragraph. When the bottom ash transport water is used in the FGD scrubber, the quantity of pollutants in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in the table in paragraph (g)(1)(i) of this section.

(ii) For discharges of bottom ash transport water generated before the date determined by the permitting authority, as specified in paragraph (k)(1)(i) of this section, the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration for TSS listed in § 423.12(b)(4).

(2) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration for TSS listed in § 423.12(b)(4).

(l) *Combustion residual leachate.* The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration for TSS listed in § 423.12(b)(11).

(m) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (b) through (l) of this section. Concentration limitations shall be those concentrations specified in this section.

(n) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (m) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

■ 6. Section 423.15 is revised to read as follows:

§ 423.15 New source performance standards (NSPS).

(a) *1982 NSPS.* Any new source as of November 19, 1982, subject to paragraph (a) of this section, must achieve the following new source performance standards, in addition to the limitations in § 423.13 of this part, established on November 3, 2015. In the case of conflict, the more stringent requirements apply:

(1) *pH.* The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(2) *PCBs.* There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

(3) *Low volume waste sources, FGD wastewater, flue gas mercury control wastewater, combustion residual leachate, and gasification wastewater.* The quantity of pollutants discharged in low volume waste sources, FGD wastewater, flue gas mercury control wastewater, combustion residual leachate, and gasification wastewater shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

(4) *Chemical metal cleaning wastes.* The quantity of pollutants discharged in chemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of chemical metal cleaning wastes times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0
Copper, total	1.0	1.0
Iron, total	1.0	1.0

(5) [Reserved]

(6) *Bottom ash transport water.* The quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the bottom ash transport water times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

(7) *Fly ash transport water.* There shall be no discharge of pollutants in fly ash transport water.

(8)(i) *Once through cooling water.* For any plant with a total rated electric generating capacity of 25 or more megawatts, the quantity of pollutants discharged in once through cooling water from each discharge point shall not exceed the quantity determined by multiplying the flow of once through cooling water from each discharge point times the concentration listed in the following table:

Pollutant or pollutant property	NSPS
	Maximum concentrations (mg/l)
Total residual chlorine	0.20

(ii) Total residual chlorine may only be discharged from any single generating unit for more than two hours per day when the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control. Simultaneous multi-unit chlorination is permitted.

(9)(i) *Once through cooling water.* For any plant with a total rated generating capacity of less than 25 megawatts, the quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum concentration (mg/l)	Average concentration (mg/l)
Free available chlorine	0.5	0.2

(ii) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10)(i) *Cooling tower blowdown.* The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed below:

Pollutant or pollutant property	NSPS	
	Maximum concentration (mg/l)	Average concentration (mg/l)
Free available chlorine	0.5	0.2

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
The 126 priority pollutants (appendix A) contained in chemicals added for cooling tower maintenance, except:	(1)	(1)
Chromium, total	0.2	0.2
zinc, total	1.0	1.0

[1] No detectable amount.

(ii) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(iii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the standards for the 126 priority pollutants in paragraph (a)(10)(i) of this section may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

(11) *Coal pile runoff.* Subject to the provisions of paragraph (a)(12) of this section, the quantity or quality of pollutants or pollutant parameters discharged in coal pile runoff shall not exceed the standards specified below:

Pollutant or pollutant property	NSPS for any time
TSS	not to exceed 50 mg/l.

(12) *Coal pile runoff.* Any untreated overflow from facilities designed, constructed, and operated to treat the coal pile runoff which results from a 10 year, 24 hour rainfall event shall not be subject to the standards in paragraph (a)(11) of this section.

(13) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (a)(3) through (10) of this section. Concentration limits shall be based on the concentrations specified in this section.

(14) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a)(1) through (13) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

(b) *2015 NSPS.* Any new source as of November 17, 2015, subject to paragraph (b) of this section, must achieve the following new source performance standards:

(1) *pH.* The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(2) *PCBs.* There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

(3) *Low volume waste sources.* The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0

(4) *Chemical metal cleaning wastes.* The quantity of pollutants discharged in chemical metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of chemical metal cleaning wastes times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
TSS	100.0	30.0
Oil and grease	20.0	15.0
Copper, total	1.0	1.0
Iron, total	1.0	1.0

(5) [Reserved]

(6) *Bottom ash transport water.* There shall be no discharge of pollutants in bottom ash transport water. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph.

(7) *Fly ash transport water.* There shall be no discharge of pollutants in fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph.

(8)(i) *Once through cooling water.* For any plant with a total rated electric generating capacity of 25 or more megawatts, the quantity of pollutants discharged in once through cooling water from each discharge point shall not exceed the quantity determined by multiplying the flow of once through cooling water from each discharge point times the concentration listed in the following table:

Pollutant or pollutant property	NSPS
	Maximum concentration (mg/l)
Total residual chlorine	0.20

(ii) Total residual chlorine may only be discharged from any single generating unit for more than two hours per day when the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control. Simultaneous multi-unit chlorination is permitted.

(9)(i) *Once through cooling water.* For any plant with a total rated generating capacity of less than 25 megawatts, the quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum concentration (mg/l)	Average concentration (mg/l)
Free available chlorine	0.5	0.2

(ii) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10)(i) *Cooling tower blowdown.* The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed below:

Pollutant or pollutant property	NSPS	
	Maximum concentration (mg/l)	Average concentration (mg/l)
Free available chlorine	0.5	0.2

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day (mg/l)	Average of daily values for 30 consecutive days shall not exceed (mg/l)
The 126 priority pollutants (appendix A) contained in chemicals added for cooling tower maintenance, except:	([1])	([1])
Chromium, total	0.2	0.2
zinc, total	1.0	1.0

[1] No detectable amount.

(ii) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(iii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the standards for the 126 priority pollutants in paragraph (b)(10)(i) of this section may be determined by engineering calculations demonstrating that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

(11) *Coal pile runoff.* Subject to the provisions of paragraph (b)(12) of this section, the quantity or quality of pollutants or pollutant parameters discharged in coal pile runoff shall not exceed the standards specified below:

Pollutant or pollutant property	NSPS for any time
TSS	not to exceed 50 mg/l.

(12) *Coal pile runoff.* Any untreated overflow from facilities designed, constructed, and operated to treat the coal pile runoff which results from a 10 year, 24 hour rainfall event shall not be subject to the standards in paragraph (b)(11) of this section.

(13) *FGD wastewater.* The quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	4	
Mercury, total (ng/L)	39	24
Selenium, total (ug/L)	5	
TDS (mg/L)	50	24

(14) *Flue gas mercury control wastewater.* There shall be no discharge of pollutants in flue gas mercury control wastewater. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph.

(15) *Gasification wastewater.* The quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	4	
Mercury, total (ng/L)	1.8	1.3
Selenium, total (ug/L)	453	227
Total dissolved solids (mg/L)	38	22

(16) *Combustion residual leachate.* The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in the following table:

Pollutant or pollutant property	NSPS	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	11	8
Mercury, total (ng/L)	788	356

(17) At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of any mass based limitations specified in paragraphs (b)(3) through (16) of this section. Concentration limits shall be based on the concentrations specified in this section.

(18) In the event that wastestreams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b)(1) through (16) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

(The information collection requirements contained in paragraphs (a)(8)(ii), (a)(9)(ii), and (a)(10)(ii), (b)(8)(ii), (b)(9)(ii), and (b)(10)(ii) were approved by the Office of Management and Budget under control number 2040–0040. The information collection requirements contained in paragraphs (a)(10)(iii) and (b)(10)(iii) were approved under control number 2040–0033.)

■ 7. Section 423.16 is amended by adding paragraphs (e) through (i) to read as follows:

§ 423.16 Pretreatment standards for existing sources (PSES).

* * * * *

(e) *FGD wastewater.* For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table following this paragraph (e). Dischargers must meet the standards in this paragraph by November 1, 2018. These standards apply to the discharge of FGD wastewater generated on and after November 1, 2018.

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	11	8
Mercury, total (ng/L)	788	356
Selenium, total (ug/L)	23	12
Nitrate/nitrite as N (mg/L)	17.0	4.4

(f) *Fly ash transport water.* Except when the fly ash transport water is used in the FGD scrubber, for any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, there shall be no discharge of pollutants in fly ash transport water. This standard applies to the discharge of fly ash transport water generated on and after November 1, 2018. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant (except when it is used in the FGD scrubber), the resulting effluent must comply with the discharge standard in this paragraph. When the fly ash transport water is used in the FGD scrubber, the quantity of pollutants in fly ash transport water shall not exceed the quantity determined by multiplying the flow of fly ash transport water times the concentration listed in the table in paragraph (e) of this section.

(g) *Bottom ash transport water.* Except when the bottom ash transport water is used in the FGD scrubber, for any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, there shall be no discharge of pollutants in bottom ash transport water. This standard applies to the discharge of bottom ash transport water generated on and after November 1, 2018. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant (except when it is used in the FGD scrubber), the resulting effluent must comply with the discharge standard in this paragraph. When the bottom ash transport water is used in the FGD scrubber, the quantity of pollutants in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in the table in paragraph (e) of this section.

(h) *Flue gas mercury control wastewater.* For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, there shall be no discharge of pollutants in flue gas mercury control wastewater. This standard applies to the discharge of flue gas mercury control wastewater generated on and after November 1, 2018. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph.

(i) *Gasification wastewater.* For any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, the quantity of pollutants in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the table following this paragraph (i). Dischargers must meet the standards in this paragraph by November 1, 2018. These standards apply to the discharge of gasification wastewater generated on and after November 1, 2018.

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (µg/L)	4	
Mercury, total (ng/L)	1.8	1.3
Selenium, total (µg/L)	453	227
Total dissolved solids (mg/L)	38	22

■ 8. Section 423.17 is revised to read as follows:

§ 423.17 Pretreatment standards for new sources (PSNS).

(a) *1982 PSNS.* Except as provided in 40 CFR 403.7, any new source as of October 14, 1980, subject to paragraph (a) of this section, which introduces pollutants into a publicly owned treatment works, must comply with 40 CFR part 403, the following pretreatment standards for new sources, and the PSES in § 423.16, established on November 3, 2015. In the case of conflict, the more stringent standards apply:

(1) *PCBs.* There shall be no discharge of polychlorinated biphenyl compounds such as those used for transformer fluid.

(2) *Chemical metal cleaning wastes.* The pollutants discharged in chemical metal cleaning wastes shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for any 1 day (mg/L)
Copper, total	1.0

(3) [Reserved]

(4)(i) *Cooling tower blowdown.* The pollutants discharged in cooling tower blowdown shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for any time (mg/L)
The 126 priority pollutants (appendix A) contained in chemicals added for cooling tower maintenance, except:	(1)
Chromium, total	0.2
zinc, total	1.0

[1] No detectable amount.

(ii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the standards for the 126 priority pollutants in paragraph (a)(4)(i) of this section may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

(5) *Fly ash transport water.* There shall be no discharge of wastewater pollutants from fly ash transport water.

(b) *2015 PSNS.* Except as provided in 40 CFR 403.7, any new source as of June 7, 2013, subject to this paragraph (b), which introduces pollutants into a publicly owned treatment works must comply with 40 CFR part 403 and the following pretreatment standards for new sources:

(1) *PCBs.* There shall be no discharge of polychlorinated biphenyl compounds such as those used for transformer fluid.

(2) *Chemical metal cleaning wastes.* The pollutants discharged in chemical metal cleaning wastes shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for 1 day (mg/L)
Copper, total	1.0

(3) [Reserved]

(4)(i) *Cooling tower blowdown.* The pollutants discharged in cooling tower blowdown shall not exceed the concentration listed in the following table:

Pollutant or pollutant property	PSNS
	Maximum for any time (mg/L)
The 126 priority pollutants (appendix A) contained in chemicals added for cooling tower maintenance, except:	([1])
Chromium, total	0.2
zinc, total	1.0

[1] No detectable amount.

(ii) At the permitting authority's discretion, instead of the monitoring in 40 CFR 122.11(b), compliance with the standards for the 126 priority pollutants in paragraph (b)(4)(i) of this section may be determined by engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by the analytical methods in 40 CFR part 136.

(5) *Fly ash transport* water. There shall be no discharge of pollutants in fly ash transport water. Whenever fly ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph.

(6) *FGD wastewater.* The quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the following table:

Pollutant or pollutant property	PSNS	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (µg/L)	4	
Mercury, total (ng/L)	39	24
Selenium, total (µg/L)	5	
TDS (mg/L)	50	24

(7) *Flue gas mercury control wastewater.* There shall be no discharge of pollutants in flue gas mercury control wastewater. Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph.

(8) *Bottom ash transport water.* There shall be no discharge of pollutants in bottom ash transport water. Whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph.

(9) *Gasification wastewater.* The quantity of pollutants discharged in gasification wastewater shall not exceed the quantity determined by multiplying the flow of gasification wastewater times the concentration listed in the following table:

Pollutant or pollutant property	PSNS	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (µg/L)	4	
Mercury, total (ng/L)	1.8	1.3
Selenium, total (µg/L)	453	227
Total dissolved solids (mg/L)	38	22

(10) *Combustion residual leachate.* The quantity of pollutants discharged in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in the following table:

Pollutant or pollutant property	PSNS	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (µg/L)	11	8
Mercury, total (ng/L)	788	356

[FR Doc. 2015–25663 Filed 11–2–15; 8:45 am]

BILLING CODE 6560–50–P

ATTACHMENT 3

GEO-HYDRO, INC.
Consulting in Geology and Hydrogeology

16 Mesa Oak
Littleton, Colorado 80127
(303) 948-1417

July 26, 2019

Mr. Christopher Bowers
Southern Environmental Law Center
Ten 10th Street NW
Suite 1050
Atlanta, GA 30309

Subject: Review of Closure Permit Application and Other Pertinent Materials
Plant Wansley Ash Pond 1

Dear Chris,

I provide the following report at the request of Southern Environmental Law Center (SELC). I have reviewed a variety of documents pertinent to the current status and proposed closure of Ash Pond 1 (AP-1) at Georgia Power Company's (Georgia Power) Plant Wansley, located near Carrollton, Georgia. Throughout this report, I cite to certain documents and evidence upon which I base my observations, opinions and conclusions. That does not mean, however, that the cited materials are the only sources of supporting evidence.

A central tenet of responsible waste management is that it be prevention-based. The United States Environmental Protection Agency (EPA) articulated this tenet in its 1993 guidance for owners and operators of solid waste disposal facilities stating: "Ground water is … used extensively for agricultural, industrial, and recreational purposes. Landfills can contribute to the contamination of this valuable resource if they are not designed to prevent waste releases into ground water … Cleaning up contaminated ground water is a long and costly process and in some cases may not be totally successful."[1]

Unlike other forms of solid waste such as municipal solid waste (MSW), inorganic coal combustion residuals and the metals they contain do not biodegrade. Coal ash that is left in unlined ash basins will be capable of leaching toxic metals into Georgia's groundwater at any time in the present, the near, or distant future for as long as soluble metals in the ash are allowed to come into contact with water. This is true for unlined facilities[2] whether or not a lateral barrier is placed along a portion of the ash impoundment, or whether a cap is placed on the top of the disposal area.

[1] EPA, 1993, p. 3
[2] Facilities constructed with no low permeability bottom liner that adequately restricts subsurface water flow

Therefore, an effective closure of coal ash storage sites requires that the coal ash waste be securely and permanently isolated from water: including precipitation, surface water, and groundwater. Failure to isolate coal ash waste from water will result in leaching of contaminants, i.e. formation of leachate. "Leachate" "includes liquid, including any suspended or dissolved constituents in the liquid, that has percolated through or drained from waste or other materials placed in a landfill, or that passes through the containment structure (e.g., bottom, dikes, berms) of a surface impoundment."[3] If released to groundwater or surface water, leachate from coal ash impoundments impairs and degrades water quality and the environment. Due to the lack of a bottom liner, unlined coal ash impoundments "allow the leachate to potentially migrate to nearby groundwater, drinking water wells, or surface waters."[4]

EPA concluded that leachate generated by coal-fired plants that use unlined surface impoundments equal about 70,300 toxic-weighted pound equivalents per year.[5] Thus, leachate from coal-fired power plants generates more equivalent toxic water pollution than the entire coal mining industry.[6] This finding illustrates the importance of implementing effective closures at coal ash impoundment sites. My review of Georgia Power's proposed Closure Plan for Plant Wansley AP-1 focused primarily on identifying factors that would inhibit the effectiveness of the proposed closure plan.

1. Background

Georgia Power is applying to the Georgia Environmental Protection Division (GAEPD) for a permit to close AP-1 under Georgia Rules for Solid Waste Management, Chapter 391-3-4-.10 (the state Coal Combustion Residuals (or "CCR") Rule). This letter documents the results of my review to date and identifies several significant findings that should be of interest and concern to GAEPD personnel. I reserve the right to amend, supplement or clarify my opinions based on the review of additional data and evidence, including any evidence uncovered by more complete and accurate disclosures by Georgia Power concerning Plant Wansley's AP-1.

2. Summary of Significant Findings

The following are the major findings that resulted from my review to date:

- The valley that formerly held a perennial creek has been buried by at least 97-feet of saturated coal ash.
- Coal ash within the AP-1 impoundment is saturated by and is degrading the quality of groundwater within, beneath, and downgradient of AP-1. This impairment and degradation of groundwater quality will continue post-closure.

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[3] EPA, 2015a, at pp. 67,838 and 67,847
[4] EPA, 2015a, at pp. 67,847
[5] EPA, 2015b, at p. 10-39 (Table 10-18)
[6] EPA, 2016, at p. 2-26 (listing equivalent pollution from other industries, including coal mining)

- The bottom of the ash is located less than 5-feet above the uppermost natural water table. In fact, the uppermost natural water table is above the bottom of the ash within AP-1, and will continue to be above that level post-closure.
- Georgia Power's Closure Plan proposes to close the unlined impoundment AP-1 in place on the floodplain of a perennial creek where the disposed waste will be subjected to re-wetting and erosion during high water events.
- The bottom of the ash impoundment is and would remain unlined under the closure plan. Lack of a bottom liner, together with the depth of the water table in relation to the depth of coal ash in AP-1 will result in coal ash remaining submerged in groundwater post-closure, degrading groundwater quality in perpetuity.
- There is no indication that Georgia Power intends to determine the extent of contamination that has already migrated from AP-1 and been detected in the current groundwater monitoring system.
- The existing groundwater monitoring system has detected elevated concentrations of ash-related contaminants, including: Boron, Calcium, Chloride, Cobalt, Fluoride, Lithium, pH, Sulfate and TDS in wells located downgradient of the ash pond.
- Georgia Power's proposed closure plan does not appear to account for the fact that ash-related contaminants will continue to be released from the AP-1 basin post-closure. Nor would the plan evaluate the fate and extent of contaminants from the capped but unlined ash impoundment.
- The true magnitude and extent of current and foreseeable post-closure releases of ash-related contaminants from AP-1 have not been evaluated under Georgia Power's current monitoring and closure plan. As a result, there has been no comprehensive and substantive evaluation of the potential impacts to human health and the environment caused by the AP-1 impoundment, even though the evidence indicates that impacts are occurring, and will continue post-closure.
- The closure plan for AP-1 will not control, minimize, or eliminate post-closure infiltration of liquids into the waste, or releases of CCR, leachate, or contaminated run-off to the ground or surface waters. The closure plan will not accomplish these objectives because it would leave tens of feet of ash unlined, submerged in groundwater within a porous media.
- For these reasons, the closure plan for AP-1 will not preclude the probability of future impoundment of water, sediment or slurry. Nor will the closure plan eliminate free liquids from AP-1 post-closure.
- Moreover, for the reasons stated herein, the closure plan will not minimize the need for further maintenance of AP-1.

3. Qualifications

I express the opinions in this letter based on my formal education in geology and over thirty-nine years of experience on a wide range of environmental characterization and remediation sites. My education includes Bachelor of Science and Masters of Science degrees in geology from

Northern Illinois University and the University of Illinois at Chicago, respectively. I am a registered Professional Geologist (PG) in Kansas, Nebraska, Indiana, Wisconsin, and North Carolina, a Certified Professional Geologist by the American Institute of Professional Geologists, and am a Past President of the Colorado Ground Water Association.

My entire professional career has been focused on regulatory, site characterization, and remediation issues related to waste handling and disposal practices and facilities, for regulatory agencies and in private practice. I have worked on contaminated sites in over 35 states and the Caribbean. My site characterization and remediation experience includes activities at sites located in a full range of geologic conditions, including soil and groundwater contamination in both consolidated and consolidated geologic media, and a wide range of contaminants. I have served in various technical and managerial roles in conducting all aspects of site characterization and remediation including definition of the nature and extent of contamination (including developing and implementing monitoring plans to accurately characterize groundwater contamination), directing human health and ecological risk assessments, conducting feasibility studies for selection of appropriate remedies to meet remediation goals, and implementing remedial strategies. Much of my consulting activity over the last 13 years has been related to groundwater contamination and permitting issues at coal ash storage and disposal sites in numerous states, including Alabama, Arizona, Colorado, North Carolina, Illinois, Indiana, Kansas, Maryland, Minnesota, Mississippi, Montana, New Mexico, Nevada, North Carolina, South Carolina, Pennsylvania, Virginia, Wisconsin. My current resume is attached.

4. Discussion

The following sections of this letter summarize my observations on reviewed documents that support these findings.

<u>Impoundment Location and Construction</u>

AP-1 is a 343-acre[7] basin that Georgia Power constructed by placing an engineered cross-valley embankment approximately 2,950 feet across an unnamed perennial creek[8] as well as a small embankment on the west end of the impoundment.[9] Materials used to build the Separator Dike surrounding the impoundment included residual soils from within and adjacent to AP-1. Earthen dams are prone to leaks in locations that may be referred to as "seeps". A construction drawing[10] and pre-development USGS topographic map[11] each show that the lowest portion of the impoundment is at an elevation of approximately 700 feet above mean sea level along the drainage.

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[7] Geosyntec Consultants, 2018a, pdf p. 8 of 1429

[8] A perennial creek or stream is one that has a continuous flow of water in at least parts of the stream bed all year round during years of normal rainfall.

[9] Georgia Power, 2016a, History of Construction

[10] Georgia Power, 2016a, History of Construction, Drawing H-12364, pdf p. 11 of 19

[11] USGS, 1964, Lowell, GA, 1:24,000 Topographic Map

Federal Coal Combustion Residuals (CCR) regulations require owners of coal ash impoundments to certify whether impoundments are lined or unlined, and whether the base of the impoundment is a minimum of 5-feet above the uppermost aquifer. In the case of Plant Wansley AP-1, Georgia Power confirms[12] that the impoundment is unlined and that the impoundment does not provide 5-feet of vertical separation between the waste and the uppermost aquifer.

USGS topo maps[13] show that prior to impoundment construction the drainage contained a perennial stream and multiple intermittent streams.[14] Following construction of the impoundment water backed up behind the dam to a normal pool elevation of 797 feet above mean sea level[15] Current aerial photographs of the site show that a coal ash delta has formed and that exposed ash (*i.e.,* ash residing within the unlined basin) now covers the deepest portions of the impoundment, including the pre-existing perennial creek channel. Assuming, at a minimum, that the exposed ash surface is no higher than the normal pool elevation,[16] the buried creek within AP-1 is now buried under 97-feet of saturated coal ash. Georgia Power estimates that AP-1 currently contains approximately 14,200,000 cubic yards of CCR.[17]

The entire footprint of AP-1, including the Separator Dike, are located within the 1% annual chance flood area[18] indicated on the current Federal Emergency Management Agency (FEMA) Flood Hazard map[19] of the area. Locating a permanent waste disposal facility on the floodplain is problematic for at least two reasons. First, even that portion of the disposed ash that is located above the water table would be re-wetted from below by rising groundwater associated with even relatively minor flood events. During high water events groundwater flows from the stream into surrounding sediments and the groundwater elevation rises in response. The result of this re-wetting of ash will be enhanced leachate production. Minimizing the potential for leachate generation and subsequent migration out of containment are key goals of permanent waste site closure that are not achieved under the Georgia Power Closure Plan.

The second issue with the location of the waste disposal facilities within the floodplain is the increased danger of damage and/or catastrophic release of coal ash during flood events. These dangers were illustrated in 2018 during the aftermath of Hurricane Florence when rising floodwaters at Duke Energy's L.V. Sutton power plant flowed through current and former ash

[12] Georgia Power, 2016b and 2016c

[13] USGS, 1964 and 2017, Lowell, GA, 1:24,000 Topographic Maps

[14] A perennial creek or stream is one that has a continuous flow of water in at least parts of the stream bed all year round during years of normal rainfall. Intermittent streams regularly cease flowing during certain times of the year.

[15] Geosyntec Consultants, 2018b, Groundwater Monitoring Plan, Figure A-4

[16] This assumption may result in an underestimation of ash delta thickness since ash is typically deposited on the surface of the delta. This practice often results in build-up of ash above normal pool elevation. This assumption also ignores any additional waste placed above the ash delta during construction of the gypsum storage facilities

[17] Georgia Power, 2016d, Initial Written Closure Plan, p.2

[18] The 1% annual chance flood, commonly referred to as the 100-year flood, is the area of the buried creek floodplain that has a 1% chance of flooding during any calendar year

[19] FEMA National Flood Hazard Layer Viewer

impoundments, breached an ash landfill, and released an unknown quantity of ash. Under major flood events such as the 1%-annual-chance-flood, the proposed containment structure and Separator Berm will both be inundated by floodwater and exposed to possible erosive forces. Locating waste containment structures above the buried creek channel and within the 100-year floodplain should be viewed, at best, as unacceptable waste management planning and practice that will contaminate waters of the State and have potentially catastrophic results for future Georgia residents.

Proposed Closure Plan

The Plant Wansley Closure Plan[20] establishes Georgia Power's intent to close AP-1 by performing the following major actions:

- Construct a deep soil mix containment structure (berm) with a concrete secant pile wall facing to create a 138-acre cap-in-place area (Consolidation Area) that separates the existing coal ash delta from the remainder of the impoundment (Closure-By-Removal Area);
- Dewatering of the CCR located within the Consolidation Area, as necessary to support closure activities;
- Dredging of the CCR from the Closure-By-Removal Area;
- Dewatering and placement of the dredged material within the Consolidation Area;
- Final grading of the Consolidation Area prior to capping; and
- Installation of a final cover system over the Consolidation Area.

The overarching problem with Georgia Power's proposed Closure Plan is the basic truth that this plan would result in establishing a permanent waste disposal cell within, and over the deepest portions of, the existing impoundment; essentially creating a waste disposal cell within a surface water lake. This is, to my knowledge, an unprecedented closure proposal that upends common precepts of proper waste containment and permanent disposal, which allows the perpetuation of significant pollution rather than the remediation of it. An annotated cross-section through the proposed Consolidation Area and Closure by Removal Area is shown in the attached drawing[21]. Items of particular concern shown on this drawing include:

- The deep soil mix and secant pile containment structure extends only to the bottom of the CCR. There is no control of groundwater flow through native soils beneath, within, or adjacent to the so-called "containment" structure within the consolidated ash footprint, rendering the "containment structure" description materially inaccurate. The secant pile does not act as a lateral barrier to the further infiltration of water into the ash basin, or migration of contaminants out of the ash basin post closure (see Attachment).
- No bottom liner or leachate collection system is proposed by the Closure Plan.

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[20] Georgia Power, 2018, Section 6

[21] Drawing shows annotations over a base layer of Closure Drawing 12 of 33.

- The water level in the Closure-By-Removal area and the Consolidation Area are both predicted to be at elevation 781.5 feet above mean sea level following closure. This clearly confirms that water in the impoundment and the leachate within the consolidated waste are predicted to be in hydrostatic equilibrium. There will be no hydraulic barrier between the waste and the impoundment.
- The proposed Closure Plan predicts that over 80-feet of ash will be saturated under normal conditions. Even more ash would be saturated during high water events.
- No modeling has been submitted to predict the directions of groundwater flow following closure, nor to predict the extent of current and future water contaminants.

These issues are troubling and illustrate the fact that Georgia Power is asking GAEPD to approve a closure plan without a complete understanding of the human health and environmental consequences of the current or future consequences of creating a permanent coal ash waste disposal facility within an existing impoundment in the manner presented here.

It is common practice to perform a comprehensive site characterization that can be used as a basis to develop a conceptual site model. This allows regulatory agencies to evaluate site characteristics and assess potential future impacts from a given closure plan. Here, the current magnitude and extent of groundwater contamination has not been determined. The lack of such data will impair GAEPD's ability to evaluate the extent of groundwater and environmental degradation that has and will result from the Closure Plan's implementation. Such considerations, particularly as they relate to potential adverse impacts to human health, should be considered of paramount importance given the many residences located in close proximity to the site.

<u>Impoundment Site Geology</u>

The groundwater monitoring plan[22] describes the geology of the AP-1 site as underlain by alluvium, saprolitic soils, and partially weathered rock, overlying fractured, crystalline bedrock. Local bedrock consists of schists with layers gneiss and quartzite. Saprolitic soils, primarily sandy silt, silty sand, sandy clay and silty clay, occur as variably-thick blanket overlying bedrock across most of the site.

<u>Impoundment Site Hydrogeology</u>

The groundwater monitoring plan[23] describes groundwater as occurring within both the overburden soils and fractured bedrock beneath the site. The water-table occurs within the overburden and is generally unconfined. Groundwater flows through the porous soils, is recharged by precipitation and typically discharges into streams and rivers. The water table surface is generally a subdued reflection of surface topography. Recharge to the bedrock aquifers

[22] AECOM, 2018, Closure Permit Application Part A- Section 6
[23] AECOM, 2018, Closure Permit Application Part A- Section 6

comes from groundwater that infiltrates into the rock through zones of enhanced permeability (*i.e.* fractures).

There is no subsurface confining layer below or adjacent to AP-1 that would otherwise act to restrict the post-closure migration of groundwater into AP-1, infiltration of liquids into AP-1, lateral migration of contaminants from AP-1, future impoundment of water within the ash basin, or the continuing presence of liquids within AP-1 post-closure.

Prior to impoundment construction, groundwater flowed from higher topographic areas located north, west, and south of the future impoundment toward discharge areas along the creek. Groundwater that discharged from the soils into the creek flowed downstream and was rapidly removed from the local hydrogeologic system.

The filling of the valley with impounded water and coal ash radically altered groundwater flow directions, pathways, ingress, and egress from the site. Under current conditions groundwater continues to flow toward the impoundment from higher elevations to the northwest, and out of the pond to recharge groundwater on the south and southeast sides of the impoundment. Flow of ash-contaminated water out of the impoundment and into groundwater under current conditions is reflected in groundwater quality monitoring results described below.

The closure plan proposes to leave the accumulated ash delta in place, without a bottom liner - over the deepest portions of the impoundment. The post-closure water elevation in both the Closure-By-Removal and Consolidation Areas is predicted to be 781.5 feet above mean sea level. There has been no evaluation of even the predicted post-closure effects of the slightly reduced water levels in the impoundment and disposal cells on water levels in surrounding areas. This is critical information needed by GAEPD to properly evaluate whether ash contaminants would be expected to continue to migrate with groundwater flow out of the impoundment toward the south as is the current situation, whether such contaminants would be expected to migrate under the containment structure to contaminate the adjacent and connected impoundment, or both.

Other generation facilities[24] that have proposed similar Cap–In-Place closure scenarios for ash impoundments have typically conducted multiple phases of groundwater flow and transport monitoring in at least an *attempt* to predict how groundwater flow directions will be altered, and to further predict how far downgradient water quality impacts may persist after waste consolidation and capping. Here, no such predictive modeling effort has been conducted in support of the AP-1 Closure Permit Application. This omission results in the lack of important data. Nevertheless, currently available information supports the findings set forth above concerning present and future groundwater degradation, future impoundment and release of

[24] Examples include the Roxboro, Mayo, and Belews Creek Generating Stations in North Carolina. On April 1, 2019, the North Carolina Department of Environmental Quality determined based on the science that excavation of these and three other unlined coal ash impoundments is the only closure option that met state standards "to best protect public health and the environment." Department of Environmental Quality, North Carolina Closure Determination April 1, 2019, see https://deq.nc.gov/news/key-issues/deq-orders-all-coal-ash-excavated

leachate, and contamination water by post-closure discharge of leachate from AP-1. Additional site investigation would serve to more accurately assess those impacts in comparison with the relatively limited dataset provided by Georgia Power.

Groundwater Quality Monitoring

The nature and extent of current groundwater contamination from AP-1 has not been adequately characterized. There are no monitoring wells completed in the shallow soil units (saprolite or partially weathered rock) located downgradient of the ash delta where contaminant migration from the ash pond can reasonably be expected to exist, given the existing data. Monitoring wells WGWC-8, WGWC-9, and WCWG-19, all completed in bedrock, are the only monitoring wells located downgradient of the coal ash source material. The lack of shallow overburden monitoring wells in this critical location should be explained or additional wells should be installed and sampled on the southeast corner of AP-1 to accurately evaluate the nature and extent of groundwater contamination that is occurring as a result of the unlined impoundment located upgradient of this area. In addition, the downgradient extent of ash-related parameters must be determined, which the current monitoring plan does not even attempt to do in light of the relatively scant number and location of wells downgradient of the ash delta.

Groundwater quality monitoring required by the Federal CCR rule has confirmed that groundwater around the AP-1 impoundment is impacted with coal ash-related contaminants. Ash-related contaminants detected at concentrations above background include the common ash–related contaminants Boron, Calcium, Chloride, Fluoride, pH, Sulfate and TDS.[25] Impacted wells include: WGWC-8, WGWC-9, WGWC-10, WGWC-11, WGWC-14A, WGWC-15, WGWC-16, and WGWC-19.[26] The table below illustrates the distribution of statistically significant increases over background water quality and/or GPS reported by Georgia Power.

A statistically significant increase (SSI) of Lithium[27] above its Groundwater Protection Standard (GPS) was documented in the 2018 annual monitoring report.[28] Well WGWC-19 is located off the southeast corner of the impoundment near the ash delta and other impacted monitoring wells. Rather than investigate the extent of the Lithium and other ash-related parameters, Georgia Power submitted an Alternate Source Demonstration[29] that purports to attribute this contamination to natural site conditions. But there is insufficient information to determine whether the Alternate Source Demonstration for Lithium is valid.

[25] Boron, Calcium, Chloride, Fluoride, pH, Sulfate and TDS are Federal CCR rule Appendix III coal ash parameters
[26] ERM, 2018
[27] Lithium is a Federal CCR rule Appendix IV coal ash parameter
[28] Atlantic Coast Consulting, 2019
[29] Atlantic Coast Consulting, 2019

Statistically Significant Increases or Exceedance of Groundwater Protection Standard								
Appendix III[30]	**WGWC-8**	**WGWC-9**	**WGWC-10**	**WGWC-11**	**WGWC-14A**	**WGWC-15**	**WGWC-16**	**WGWC-19**
Boron[31]	SSI	SSI					SSI	
Calcium	SSI						SSI	
Chloride	SSI						SSI	
Fluoride	SSI	SSI				SSI	SSI	SSI
Sulfate	SSI	SSI				SSI	SSI	
TDS	SSI					SSI	SSI	
pH				SSI	SSI			
Appendix IV								
Lithium[32]	GPS	GPS	GPS					GPS

There is no question that lithium is a very common contaminant found in groundwater at coal ash disposal sites. In addition, other common ash-related constituents were detected in the same wells evaluated in the Alternate Source Demonstration. In fact, with the exception of well WGWC-10, the wells that showed elevated concentration of Lithium are also impacted by other common coal ash contaminants. Georgia Power has not attempted to explain how these common coal ash contaminants could be attributable to another source nor made any apparent effort to determine the magnitude and extent of ash-related groundwater contamination caused by AP-1. Characterization of the extent of groundwater impacts downgradient of AP-1 is necessary to adequately determine if any of the detected contaminates are the result of natural conditions, or, more likely, if this very common ash-related contaminant is further indication of contamination from AP-1. The Company appears more interested in attributing away the detected pollution to sources other than its massive coal ash waste disposal unit than in providing an accurate picture of site contamination.

The above findings are based on my review of available sources, including materials submitted by Georgia Power to GAEPD, the content of Georgia Power's CCR Rule Compliance Data and Information website, and my education, qualifications, experience, and expertise. In short, there are many reasons that I consider this to be one of the most poorly conceived Closure Plans that I have ever reviewed. I would be happy to discuss the planned closure of Plant Wansley AP-1 with you and/or GAEPD at any time.

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30 Identification of SSI's for Appendix III parameters is found in Section 4.2 of the 2017 Annual Monitoring Report

31 The 2017 Annual Report indicates that Boron was detected at elevated concentration but that two consecutive monitoring events to be considered a SSI. The 2018 Annual Monitoring Report simply says (Section 4.2) that Appendix III constituents have not returned to background levels. I assume that this includes Boron.

32 Exceedance of Lithium GPS described in Section 4.2.1 of the 2018 Annual Monitoring Report

Please let me know if you have questions or comments.

Sincerely,

Mark A. Hutson, P.G.
303-948-1417
mhutson@geo-hydro.com

Attachments

Documents Reviewed

Data and information sources reviewed included the following documents:

Atlantic Coast Consulting, 2019, 2018 Annual Groundwater Monitoring and Corrective Action Report, Georgia Power Company, Plant Wansley Ash Pond, January 31, 2019, https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-wansley/20190131_AnnualGWReport_WAN_AP_FINAL.pdf

EPA, 1993, *Criteria for Solid Waste Disposal Facilities, A Guide for Owners/Operators*, EPA/530-SW-91-089, March 1993, *available at* https://www.epa.gov/sites/production/files/2016-03/documents/landbig.pdf

EPA, 2015a, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. (November 3, 2015) (40 C.F.R. Part 423), available at https://www.govinfo.gov/content/pkg/FR-2015-11-03/pdf/2015-25663.pdf

EPA, 2015b, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-15-007 (September 2015), available at https://www.epa.gov/sites/production/files/2015-10/documents/steam-electric-tdd_10-21-15.pdf

EPA, 2016, Annual Effluent Guidelines Review Report, EPA-821-R-16-002 (June 2016), available at https://www.epa.gov/sites/production/files/2016-06/documents/2015-annual-eg-review-report_june-2016.pdf

ERM, 2018, 2017 Annual Groundwater Monitoring and Corrective Action Report, Georgia Power Company – Plant Wansley Ash Pond, January 31, 2018, https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-wansley/20180131-annualgwreport-wan-ap-final.pdf

FEMA National Flood Hazard Layer (NFHL) Viewer, 1% Annual Chance of Flood Hazard - https://fema.maps.arcgis.com/apps/webappviewer/index.html?id=29f87515702d4845a906419b287e2049

Georgia Power, 2016a, History of Construction, 40 C.F.R. Part 257.73(c)(1)(i)-(xii), Plant Wansley Ash Pond (AP-1), https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-wansley/20161017-constrhist-wan-ap1-final.pdf

Georgia Power, 2016b, Location Restriction Demonstration, Uppermost Aquifer (40 C.F.R. 257.60), plant Wansley Ash Pond 1 (AP-1), https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-wansley/wansley_ap-1_aquifer_lrd.pdf

Georgia Power, 2016c, Liner Design Criteria, 40 C.F.R. Part 257.71, Plant Wansley Ash pond (AP-1), https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-wansley/20161017-liner-wan-ashponf-final.pdf

Georgia Power, 2016d, Initial Written Closure Plan, 40 C.F.R. Part 257.102, Plant Wansley Ash pond (AP-1), https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-wansley/20161017-clospln-wan-ap-final.pdf

Geosyntec Consultants, 2018a, Coal Combustion Residuals (CCR) Unit, Permit Application, Part B; Permit Documents, Plant Wansley Ash Pond (AP-1) Closure, Heard and Carroll Counties, Georgia, November 2018.

Geosyntec Consultants, 2018b, Coal Combustion Residuals (CCR) Unit, Permit Application, Part A; Permit Documents, Plant Wansley Ash Pond (AP-1) Closure, Heard and Carroll Counties, Georgia, November 2018.

United States Geological Survey, 1964, Lowell, GA, 1:24,000 Topographic Map.

United States Geological Survey, 2017, Lowell, GA, 1:24,000 Topographic Map.

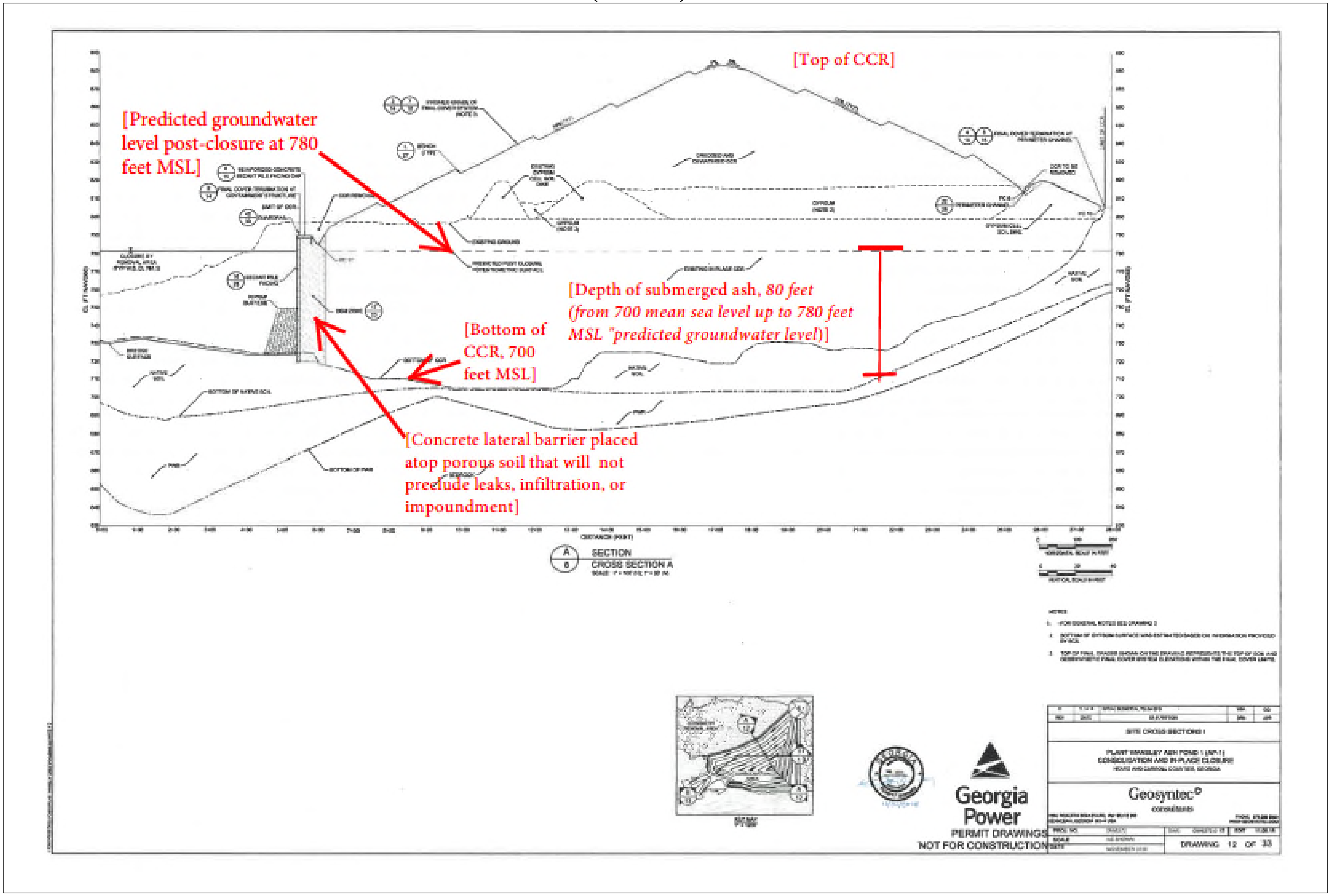
Attachment

Cross Section

(enhanced in red type for illustration purposes)

GEO-HYDRO, INC

Annotated Closure Drawing
(12 of 33)



Attachment

Resume of Mark Hutson, P.G

Mark A. Hutson, P.G.

Summary of Qualifications

Over 38 years professional experience performing and managing site characterization, RI/FS's, RFI's, and soil and/or groundwater remediation projects. Management experience includes all aspects of projects for industrial, governmental, and non-profit clients. I have provided technical review, comments, and oversight on preparation of numerous permit applications and a wide array of projects.

Professional Experience

Geo-Hydro, Inc., 2006-Present, Principal/Senior Scientist

Weston Solutions, Inc., 2002-2006, Senior Project Manager/Business Line Operations Manager

Ellis Environmental Group, LLC, 2001-2002, Senior Project Manager

Foothill Engineering Consultants, 1997-2001, Senior Project Manager

Burns & McDonnell Waste Consultants, Inc., 1996-1997, Senior Project Manager

Hydro-Search, Inc., 1990-1996, Senior Project Manager/Operations Manager

Roy F. Weston, Inc., 1984-1990, Senior Geologist/ Project Manager

University of Illinois at Chicago, 1982-1984, Teaching Assistant

Ecology and Environment, Inc., 1980-1982, Hydrogeologist

Illinois Environmental Protection Agency, 1978-1980, Environmental Protection Specialist

Professional Registrations, Memberships, and Affiliation

Professional Geologist - Wisconsin (No. 889), Illinois (196.001465), Indiana (No. 754), Kansas (No. 709), Nebraska (No. G-0329), North Carolina (No. 2513)

American Institute of Professional Geologists - Certified Professional Geologist (No. 7302)

Colorado Ground Water Association - (Past-President 2015-2016), President 2014-2015, Vice President 2013-2014, Education Committee Chair, 2011-2018)

Education

M.S., Geology, University of Illinois at Chicago, 1989

B.S., Geology, Northern Illinois University, 1978

Graduate Studies in Business, Northern Illinois University, 1979-81

Various courses on computer software and geographic information systems

Select Project Experience

Technical Oversight and Consulting

- Consultant tasked with reviewing and summarizing water quality data from 66 Coal Combustion Residual sites to gain insight into the nature and magnitude of the documented impacts that CCR units have on groundwater quality. Results were submitted to EPA by my client during the public comment period on proposed revisions to the 2015 Coal Combustion Residual Rules.

- Consultant tasked with reviewing and providing my Expert Opinions on EPA's proposed revisions to the 2015 Coal Combustion Residual rules. Opinions were submitted to EPA by my client during the public comment period.

- Consultant tasked with reviewing and providing comments on Site Assessment Plans, Comprehensive Site Assessments, and Corrective Action Plans for coal ash impoundments at the Mayo, Roxboro, and Belews Creek Generating Stations in North Carolina. Coal ash impoundments at each of these sites were constructed in stream valleys and resulted in burying perennial streams below sluiced ash.

- Consultant for the Western Environmental Law Center initially tasked with reviewing and providing comments on the mine permit application for the Bull Mountains Mine, Montana. I was subsequently asked to provide testimony about concerns over inadequate evaluation of potential impacts to springs and seeps as well as water supplies on surrounding properties.

- Consultant tasked with reviewing closure plan information and monitoring reports from the Santee Cooper Grainger Generating Station ash pond closure. The site is located near Conway, SC. Documents were reviewed to evaluate the effectiveness of the proposed closure plan and comments were provided to counsel for use in negotiations with the company.

- Technical Consultant tasked with reviewing and preparing comments on the Draft Environmental Impact Statement for the Four Corners Power Plant and Navajo Mine Energy Project in New Mexico. Reviewed documentation from Office of Surface Mining Reclamation and Enforcement sources and prepared comments covering the effects of current and previous mining and coal ash disposal practices and identifying proposed activities likely to adversely impact environmental quality.

- Consultant providing support to counsel by reviewing and providing comments on Groundwater Assessment Work Plans and Drinking Water Supply Well and Receptor Surveys at 14 coal ash disposal facilities located in the southeast. The document reviews were conducted in order to evaluate the appropriateness of proposed characterization, make recommendations to improve characterization, and identify any sites that showed a particularly high risk to off-site receptors.

- Consultant tasked with reviewing and preparing comments on the 2012 reports covering the Plant Area, Stage One and Stage Two Evaporation Ponds Area, and Units 3 & 4 Evaporation Holding Ponds Area of the Colstrip Steam Electric Station located at Colstrip, MT. Reviewed documents and prepared comments and talking points that were submitted subsequently submitted to regulators.

- Consultant on the Pines Groundwater Plume Site through a USEPA Technical Assistance Program grant from PRPs to local citizens' group. The Pines site is a coal combustion waste landfill with significant spread of contaminants. Provide assistance to the citizens through grant to provide assessment and feedback on site work products as they are developed and implemented, explain the remediation processes and activities to the citizens, and serve as technical liaison between citizens and remediation team.

- Technical Consultant tasked by with reviewing a variety of documents and monitoring data from the Rosebud Mine located near Colstrip, MT. Document and data reviews included groundwater monitoring data, MPDES permits and discharge monitoring reports, and permit renewal documents. In each case, documentation and data were reviewed and comments were prepared and submitted to counsel.

- Technical Consultant providing support at the Massachusetts Military Reservation (MMR) on Cape Cod, MA. Under contract to the Corps of Engineers, provided third-party technical support services for the Selectmen of four towns surrounding MMR from 1998 thru 2011. The project involved oversight of impact area characterization and remediation activities including UXO location and disposal, and characterization of explosive impacted soil and groundwater, volatile organics, and perchlorate. Provided technical review of remediation data as well as comments and advice to the Selectmen on technical issues.

- Environmental Consultant to the City of Afton, MN to review and provide comments on an application to develop a coal combustion waste landfill on the site of a former sand and gravel mining operation. On behalf of the City of Afton, GHI reviewed the available materials, identified data gaps and potential concerns, and submitted detailed comments on the plan. Major concerns included the susceptibility of the local water supply to contamination from the facility, the unacceptable geologic characteristics of the site for construction of a waste disposal facility, poor characterization of wastes to be placed in the facility, improper modeling of the site conducted in support of the EIS, and the location of many potential receptors downgradient of the facility.

- Project Manager and Consultant tasked with reviewing and providing technical comments on the Faulkner, Westland and Brandywine coal combustion waste disposal facilities in rural Maryland. Provided comments on the adequacy of characterization of the nature and extent of contaminants released from these facilities. Subsequently supported the legal team in negotiating the details of necessary actions to be taken during closure of these facilities to protect human health and the environment.

- Consultant tasked with reviewing and preparing comments on a permit amendment application for the Savage Mine located in eastern Montana. Comments submitted to counsel primarily concerned the adequacy of the site characterization, the hydrologic balance and probable hydrologic consequences of proposed application.

- Project Manager and Consultant on the review and preparation of technical comments on an application by a major utility to develop an unlined coal combustion waste (CCW) disposal facility in western Kansas. Major issues included the leachability of CCW in the landfill environment, inadequacy of the proposed groundwater monitoring plan and the lack of necessary groundwater protection systems in the design. Comments were provided to counsel for inclusion in the public review process.

- Environmental Consultant tasked with reviewing and preparing comments on a permit application for a proposed lignite mine located near South Heart, North Dakota. Comments submitted to counsel included identification of inadequacies in the site characterization, the monitoring plan, the Probable Hydrologic Consequences, and the evaluation of potential alluvial valley floors. Comments were submitted to counsel.

- Project Manager and Consultant for Robinson Township and Environmental Integrity Project on a review of a permit application submitted to the State of Pennsylvania to mine coal refuse, generate electricity and dispose of coal combustion waste at the location of a large coal refuse pile. Services included permit application review and preparation of comments. Review identified deficiencies in the characterization of geologic materials, groundwater, surface water, and the hydrologic balance provided in the permit application.

- Geologist on a geologic and hydrogeologic assessment of a proposed regional landfill in Kendall County, Il. Research documented problems with the geologic and hydrogeologic characterization, including karst features in the area that had not been noted or anticipated in the permit application materials.

Site Characterization and Remediation

- Lead author on a Groundwater Impact Assessment at a coal combustion waste disposal facility in Illinois. This project was conducted to assist an electric generating station investigate the nature and extent of contaminants that had been released to the groundwater and to investigate remedial options necessary to minimize future releases. Results of this study are currently being implemented by the company and are projected to adequately contain contamination and avoid exposures to surrounding residents.

- PCP Contaminated Soil Remediation, Beaver Wood Products, Columbia Falls, MT, Project Manager. Manager of a project to investigate, excavate and bio-remediate PCP impacted soils at a former pole treatment site. Soil treatment was conducted via an on-site Land Treatment Unit (LTU). At the time of project completion over 20,000 cubic yards of impacted soil had been excavated, treated, and returned to the site. Responsible for project planning and execution, budget and schedule tracking, and cost control.

- Project Manager of a project to remediate and remove an oil interceptor pond containing PCB-contaminated sediment at a generating facility in North Dakota. Oily sludge in the pond contained PCB's in sufficient concentrations to require special handling and disposal. Responsible for all aspects of the project including evaluating remedial action alternatives, preparing construction plans, representing the client with regulatory agencies, and implementation of the approved site closure. Fly ash was added as a stabilizing agent to stabilize the sediment within the pond. Stabilized and characterized sediment was shipped to a permitted TSCA facility for disposal.

- Remediation of hydrocarbon contaminated soils at natural gas collection and pumping Stations, KN Energy, Project Manager. The project consisted of identification of areas of visually impacted soils, excavation of soils to visually clean, screening soils with field instrumentation, collecting verification samples for laboratory analysis, directing contaminated soil excavation, and replacing excavated soil with clean backfill. Impacted soil was transported to pre-existing landfarm areas for treatment by the client.

- Project Manager and Principal Investigator on a mixed waste treatability study performed for Kerr-McGee Corporation to investigate methods of making radiologically impacted hydrocarbon sludge acceptable for disposal without increasing the total volume. The project included characterization of the physical, chemical, and radiologic composition of the available waste materials, and evaluating the feasibility of combining wastes to produce an acceptable material. Pilot scale testing was conducted on the most promising materials to identify the proportions necessary to produce an optimum mixture.

- Project Manager on a groundwater remedial design project at a Phillips Petroleum facility in Beatrice, Nebraska. Project tasks included a general site characterization, geophysical surveys, soil borings and chemical analysis, pump testing, and design of ground water remediation system. Remedial technologies selected utilized air stripping and carbon absorption.

- Project Geologist involved in the installation of a petroleum hydrocarbon recovery system at the Hess Oil refinery on St. Croix US Virgin Islands. Activities included daily coordination with refinery personnel and drilling contractors, logging and installing recovery wells, and performing recovery tests on completed installations.

- Project Manager of a program to investigate, design and construct ground water remediation systems at three Chevron facilities in Puerto Rico. Project included ground water characterization, pump testing and conceptual and detailed designs of remediation systems. Systems were constructed, operated for a period of approximately 2 years and have now been removed.

- Prepared Detailed Plans and Specifications for construction and operation of a land treatment unit to remove hydrocarbon and volatile organics from soil in North Dakota, Project Manager. Managed a team of people involved in preparation of a complete design and specifications package for construction and operation of a land treatment unit to treat soils impacted with petroleum hydrocarbon and chlorinated solvents. This project was completed on schedule, has been built and was successfully completed.

- Project Manager and author of a revised and updated Site Decommissioning Plan for the Kerr-McGee facility in Cushing, OK. Plan preparation included summarizing site conditions, establishing clean-up criteria, specifying remedial actions for each of 16 radioactive materials areas (RMAs) including measurement and sorting of materials, and planning final survey procedures. The scope of the remediation was negotiated with Nuclear Regulatory Commission headquarters and regional personnel as the document was being drafted to attempt to minimize the time for subsequent review and approval.

- Project Manager of a multi-million dollar U.S. Army program to identify and properly abandon wells located on Rocky Mountain Arsenal (RMA) that could possibly be conduits for downward migration of contamination. This work was conducted in accordance with an Administrative Order ceasing remedial activities at RMA. Over 350 wells were identified and abandoned under this program.

- Project Manager on the characterization of Bombing Target 5 for the Pueblo of Laguna, NM. Portions of the Laguna Pueblo were used during WWII as a bombing practice area. The project consisted of preparation of detailed UXO planning documents, surface clearance of the area around the target, and excavation of the target to a depth of 5-feet below the surface. Material found to potentially present and explosive hazard were collected on-site and detonated on-site at the end of the project. The Pueblo of Laguna and the Corps of Engineers approved all procedures and field activities.

- Multi-phase AFCEE Soil And Groundwater Investigation And Monitoring Program at the Former Bergstrom Air Force Base in Austin, Texas, Project Manager. Investigation areas included an oil-water separator at an engine test facility, a former maintenance facility, and the base landfills. Soils were contaminated with heavy metals including lead and solvents. Contaminated soils were excavated and disposed at an off-site facility. Closure reports for all three areas were submitted and approved by TNRCC.

- Project Manager on a contract to the Department of Energy to perform a surface clearance for UXO at three former bombing targets at the Tonopah Test Site in Nevada. Materials encountered included practice bombs and rockets that had been fired several decades ago. UXO technicians inspected each piece of material for potential explosive hazards. Materials that potentially contained explosive hazards were blown-in-place by Tonopah personnel. Scrap material was secured on-site and disposed appropriately at the end of the project.

- Project Manager for the investigation of subsurface contamination at several high priority solid waste management units at Rocky Flats Plant. Work included identification and characterization of surface and subsurface soil contamination, source characterization, and evaluation of ground water quality and movement.

- Project Manager under contract to Rockwell International to develop usable and defensible background geochemical data sets for various media at the Rocky Flats Plant. The occurrence of low-level radioactive material contamination from many years of plant operations, surrounding land uses, and atomic test fallout necessitated an extensive program to develop data and apply statistical analysis to describe background conditions. Additional statistical testing was performed to identify investigative results that showed results above defensible background values.

- Project Manager on a multi-phase soil and groundwater investigation and monitoring program at the former Bergstrom Air Force Base in Austin, Texas. Investigation areas included an oil-water separator at an engine test facility, a former maintenance facility, and the base landfills. Closure reports for all three areas are currently being prepared.

- Project Manager on a geophysical survey program at the Rocky Flats Plant designed to identify sources of chemical and radiological contamination at high priority solid waste management units. Surveys included electromagnetic, magnetic, and electrical resistivity methods used in conjunction with aerial photographs to identify possible source areas.

- Project Manager on a contract for USEPA Region 5 to plan and execute an investigation of the Federal Marine Terminals site near Detroit, Michigan. The investigation included a detailed review of historical aerial photographs, geophysical surveys of potential burial sites, soil sampling, monitoring well construction and sampling, and preparation of a site investigation report. Documentation and depositions on findings were provided to Region 5 enforcement.

- Project Geologist on a preliminary investigation of possible JP-4 impacts to soil and groundwater from the fueling system at Forbes Field Air National Guard base in Topeka, KS. The investigation included drilling through runway and ramp areas, around fuel storage facilities, and evaluation of possible migration pathways.

- Project Geologist on a project to use electromagnetic geophysical techniques to trace the lateral migration of shallow, high TDS groundwater plumes associated with three DOE uranium mill tailings sites located in different parts of the western U.S. Results of these surveys showed that electromagnetics was useful for tracing the plumes and allowed a minimal number of subsequent monitoring wells to be installed to quantify leading edge impacts.

Remedial Investigations/Feasibility Studies

- Project Manager for the Remedial Investigation at a former Atlas Missile site located near Holton, Kansas, Responsible for completion of a site investigation and risk assessment for the Kansas City District. Direct push soil sampling, sonic drilling and well installation, and indoor air, surface water, sediment, and groundwater sampling have been conducted in and around the former facility to determine the level and extent of contamination that may be present. An ecological and human health risk assessment was conducted to evaluate the potential health risks associated with the site.

- Project Manager on a Remedial Investigation and Focused Feasibility Study of JP-4 contaminated soils at the Fire Protection Training Area at Minot Air Force Base. Performed under contract to the U.S. Corp of Engineers, this project utilized Laser Induced Fluorescence, an innovative investigation technique, to characterize the extent of subsurface contamination. The Focused Feasibility Study examined eight potential remedial actions and was successful in gaining State acceptance of on-site land treatment as the chosen remedial alternative.

- Project Manager for the Remedial Investigation/Feasibility Study (RI/FS) of the Landfill Solids and Gases Operable Units at the Lowry Landfill CERCLA site. This project involves the characterization and assessment of the extent of potential contamination within the unsaturated solid and gaseous phases of the materials at this high profile site. Responsible for coordinating the activities of up to 30 project staff assigned to multiple concurrent tasks. Responsibilities also included extensive coordination and interaction with multiple clients and PRP groups as well as the Colorado Department of Health and Environment and USEPA Region 8 personnel.

- Technical Advisor under contract to EPA Region V on the Remedial Investigation at the Marion Bragg Landfill CERCLA site. Provided technical assistance to the project team related to investigation techniques to be used in characterizing the landfill and surrounding areas, including evaluating and providing remedies to difficult well installation encountered during the remedial investigation.

- Project Manager on a Feasibility Study/Risk Assessment program at a former Rocketdyne fuel test facility located near Spanish Springs, NV. This program included performing a risk assessment on an impacted groundwater plume, performing a feasibility study to evaluate appropriate remedial options, and performing treatability studies on two alternatives to verify and quantify effectiveness and estimate costs.

- Project Geologist and Site Manager on contract to USEPA Region V on the Remedial Investigation of the Skinner Landfill CERCLA site located near Cincinnati, OH. Prepared planning documents including the Sampling and Analysis Plan, Quality Assurance Project Plan, and Health and Safety Plan. Managed implementation of the remedial investigation that included geophysical surveys, aquatic biology surveys, well installation, and soil and groundwater sampling.

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Hutson, M.A., and R. J. Karnauskas, "Groundwater Contamination Study, Forbes Field Air National Guard Based, Shawnee County Kansas, Defense Technical Information Center, 1985.

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Chapel Hill, NC, 2017, Roanoke River Basin Association vs. Duke Energy Progress, LLC, United States District Court for the Middle District of North Carolina, Civil Action Nos. 1:16-cv-607 and 1:17-cv-0042. Deposition concerning opinions expressed in Expert Report.

Chapel Hill, NC, February 2017, State of North Carolina, ex rel, North Carolina Department of Environmental Quality, et. al. v. Duke Energy Progress, LLC., Civil Action No. 13-CVS-11032 and 13-CVS-14461. Deposition concerning opinions expressed in Expert Report.

Chapel Hill, NC, July 2016, State of North Carolina, ex rel, North Carolina Department of Environmental Quality, et. al. v. Duke Energy Progress, LLC., Civil Action No. 13-CVS-11032 and 13-CVS-14461. Deposition concerning opinions expressed in Expert Report.

Denver, CO, 2015, Montana Environmental Information Center et. al. v. Montana Department of Environmental Quality, et. al., 16th Jud. Dist. No. DV 12-42. Deposition concerning opinions expressed in Expert Report.

Denver, CO, 2015, City of Loves Park, IL vs. Browning Ferris Industries. Deposition on behalf of Browning Ferris Industries regarding meetings held and documents produced during employment at the Illinois Environmental Protection Agency.

Chicago, IL, 1982, United States Environmental Protection Agency vs. Federal Marine Terminals. Deposition on behalf of USEPA regarding findings of site investigation at a Federal Marine Terminals site in Detroit, Mi.

Dixon, IL, 1980, Illinois Environmental Protection Agency vs. Lee County Landfill, Testified in state court on behalf of the IEPA regarding violations of state environmental laws at the Lee County landfill.

ATTACHMENT 4

The New York Times | https://nyti.ms/2PY0tRR

Florence's Floodwaters Breach Defenses at Duke Energy Plant, Sending Toxic Coal Ash Into River

By Glenn Thrush and Kendra Pierre-Louis

Sept. 21, 2018

NAVASSA, N.C. — With floodwaters continuing to rise in the wake of Hurricane Florence, state officials and environmentalists are closely monitoring the breach of a dam that has flooded a hazardous stockpile of coal ash, some of which has spilled into the Cape Fear River.

On Friday, Duke Energy shut down a power plant near Wilmington after a dam breach between 100 and 200 feet wide, at the south end of Sutton Lake, allowed floodwaters to swamp two basins containing huge stockpiles of arsenic-laced ash.

Duke's L.V. Sutton facility has been a focus of increasing concern for environmentalists and regulators since last week, when rains from Hurricane Florence caused a coal ash landfill at the site to erode, spilling waste onto a local roadway.

Coal ash is the powdery substance that remains after burning coal. The Environmental Protection Agency links the substances that it contains — including heavy metals like arsenic and lead — to nervous-system problems, reproductive issues and cancer.

It was not immediately clear how much ash was released. The extent of the threat will depend on how quickly the breach can be stopped, state officials said.

The state is still reeling from record-breaking flooding that has left many of the region's roads, including a long stretch of Interstate 95 south of the Virginia border, closed to traffic.

And the danger of more flooding remains. The Cape Fear River is scheduled to crest tomorrow morning at 31.3 feet, more than seven feet above its historic flood stage. Water levels will remain high through Tuesday.

Coal ash is not the only pollutant to cause North Carolina woes in the wake of Florence. The state is home to 9.7 million pigs that produce 10 billion gallons of manure each year. Most of that manure is stored in large earthen lagoons. In the wake of Florence and the record-breaking amount of water the storm has poured onto the region, a growing number of those lagoons are flooding.

[At least three infants were among the victims of Hurricane Florence.]

As of midday on Friday, at least 54 lagoons have discharged their waste into the environment, another 76 are at risk of doing so, and six have some form of structural damage that may have led to the release of pig feces. The number is expected to increase as more farmers return to their land.

State inspectors, who conducted a drone survey of the area on Friday, said there appeared to be "no structural issues" with the inner containment walls, or impoundments, of the basins, according to Bridget Munger, spokeswoman for the North Carolina Department of Environmental Quality.

They are monitoring the situation in "real time" and plan to conduct an investigation into the causes of the failure once the situation has stabilized, Ms. Munger said in an email.

The dam was inspected within the last month and no major problems were discovered, state officials said.

"This is a crisis that we're addressing but it's in the context of a huge state emergency, so that's just part of the big picture for us," Ms. Munger said.

Gov. Roy Cooper of North Carolina said in a statement on Friday that "a thorough investigation of events will soon follow to ensure that Duke Energy is held responsible for any environmental impacts by their coal ash facilities."

A spokesperson for the Environmental Protection Agency said the agency had not been out to the site, and that it would lend its support to state officials at their request.

As state officials fretted over the plant, residents and workers in the surrounding area were impatient to get back to their daily routines and were concerned about potential damage.

"The dam really worries me. The idea that it could spill over and spread chemicals is really concerning," said Charles Holliday, 27, who was clearing out debris from his family's yard in the small town of Navassa, the nearest residential area to the plant. "This whole area has a lot of industrial plants and chemicals and that kind of thing. So you add it all up and, yes, it's something we are all going to get a little panicked about."

The river has already spread hundreds of yards beyond its banks, turning the piney flats west of Wilmington into a muddy lagoon punctured by tilting trees and half-submerged railroad bridges.

The plant itself, cordoned off by security but visible from a highway overpass, was covered by a thin pool of water, with the area closest to the lake appearing to be the most inundated.

Peter Harrison, a lawyer with Earthjustice, an environmental nonprofit, took a boat on the river to see the site himself. He said that there were multiple places where the dam around the lake had breached, and that the lake water was pouring into the river. From what he could see, he added, the lake water appeared full of coal ash.

"You can just see that swirling down the river for like miles and miles," Mr. Harrison said.

Avner Vengosh, a professor of earth and ocean sciences at Duke University, said, "We'll probably never know how much has spilled into the river." Because the spill stems from large-scale flooding over a wide area, it's difficult to calculate how much ash is entering the river.

The breach of the dam imperils two unlined coal ash ponds on site, which contain a combined 2.1 million cubic yards of coal ash, according to a report prepared for Duke Energy this year. That amount of coal ash would fill a large sports stadium.

Scrutiny of coal ash has increased since 2008, when the Kingston Fossil Plant in Harriman, Tenn., spilled 5.4 million cubic yards of coal ash into the environment. The cleanup cost more than $1 billion.

Last week, the storm caused a coal ash landfill at the Duke plant to erode, spilling about 2,000 cubic yards of the ash onto an adjacent roadway.

The spill was quickly cleaned up, the company said. But the Waterkeeper Alliance, an environmental group, disputed that, saying at least some of the coal ash remains in the area.

In 2014 Duke Energy's Dan River plant in Eden, N.C., spilled 39,000 tons of coal ash into the Dan River, prompting the state to order all of Duke's coal ash ponds closed. That process is not yet complete.

In May 2015, the Justice Department announced a $102 million fine against Duke Energy after the utility pleaded guilty to nine criminal violations of the Clean Water Act at several of its North Carolina facilities.

The fine included a $68 million criminal penalty and $34 million for environmental projects and land conservation to benefit rivers and wetlands in North Carolina and Virginia. Four of the nine charges were related to the Dan River spill. The other violations were based on allegations of historical violations at the company’s other operations.

The L.V. Sutton plant now burns natural gas, but until 2013 it housed a three-unit, 575-megawatt coal-fired plant. The coal ash from that operation remains on site, with the oldest of the ash basins dating back to 1971.

The coal ash landfill at Duke’s L.V. Sutton plant, which spilled last week, was supposed to provide secure storage for the site’s two coal ash ponds, but the fact that it is already failing now has some environmental groups questioning its structural integrity.

“You know the thing with the Tennessee Valley river spill, and the same thing with the Dan River spill, a lot of that ash was never recovered,” Lisa Evans, a lawyer with Earthjustice, said. “If you spill into a lake and that lake water continues to spill into that river rapidly, you’re going to have maybe even a bigger cleanup problem.”

“If you have two million tons of ash going into that lake,” Ms. Evans added, “that lake is dead.”

For more news on climate and the environment, follow @NYTClimate on Twitter.

Ivan Penn contributed reporting from Los Angeles.

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A version of this article appears in print on Sept. 22, 2018, Section A, Page 11 of the New York edition with the headline: Toxic Coal Ash Spills Into Cape Fear River

The Washington Post
Democracy Dies in Darkness

Dam breach sends toxic coal ash flowing into a major North Carolina river

By **Brady Dennis**, **Steven Mufson** and **Juliet Eilperin**

September 22, 2018 at 5:41 p.m. CDT

North Carolina floodwaters continued to inundate a 47-year-old basin of toxic coal ash alongside Duke Energy's L.V. Sutton power plant on Saturday, sending polluted waters pouring into a man-made lake and then into the Cape Fear River.

The rising waters also swamped a 625-megawatt natural gas plant at the site, forcing it to shut down. The water at the plant was at least six inches deep, Duke spokeswoman Paige H. Sheehan said. Video released by state regulators Saturday showed equipment and buildings at the plant poking up from a vast expanse of water.

The company said in a news release Friday that workers were moving "large stones and other materials" to help plug gaping holes in the dams and on Saturday added it was bringing additional construction materials from across the state. Sheehan said Duke has deployed booms with curtains below them to try to contain some of the leaking material.

The breakdown in the defenses at the Duke plant underscored how even though Hurricane Florence is over, rising river waters keep adding to the environmental mess left in the storm's wake. There were at least 34 hog lagoons spewing feces and urine into the surrounding areas, according to state officials. Nine more were inundated by floodwaters, and 47 on the edge of overflowing.

"There is an urgent need for both hog lagoons and coal ash ponds to be removed from the flood-prone areas near our rivers and lakes before the next climate change fueled superstorm hits us," Kemp Burdette, part of a network of environmental activists protection U.S. rivers, said in a statement Saturday.

Satellite photographs taken of Camp Lejeune by the U.S. Geological Survey show large black splotches spilled from major rivers into the ocean. The Environmental Working Group said the photos "demonstrate the consequences of concentrating confined animal feeding operations . . . in low-lying areas along sensitive flood plains."

Fears about the situation at Duke Energy's L.V. Sutton power plant near Wilmington have been growing since before Florence made landfall. Earlier in the week, rainfall from the storm punched holes in the wall of a separate coal ash landfill also near the former coal plant, which sits on the banks of man-made Sutton Lake and near the Cape Fear River, failed in several places. A special black membrane installed to contain the waste was torn open in at least two spots.

Duke Energy estimated last weekend that the storm had washed away more than 2,000 cubic yards of coal waste — enough to fill more than 150 dump trucks. The environmental group Waterkeeper Alliance said in a statement Saturday that breaches at the landfill "swallowed a bulldozer and a tractor."

On Friday came more bad news. The company said the dam separating the Cape Fear River from man-made Sutton Lake, which holds water used to cool the power plant, suffered one large breach and several smaller ones. Meanwhile, a steel wall separating the oldest of two remaining coal ash disposal basins at the site was submerged by floodwater. The National Weather Service said water levels in the river would continue to rise into Saturday and stay above record levels into next week.

“We cannot rule out that coal ash is moving into the river,” Sheehan said in an email Friday.

The North Carolina Department of Environmental Quality said it had several teams monitoring conditions at the Sutton facility and remaining in close contact with on-site engineers. On Friday morning, the company notified state officials of a breach of between 100 and 200 feet at the south end of Sutton Lake. State officials were using drones to monitor the conditions at the site.

“While the state is currently in emergency response mode, a thorough investigation of events will soon follow to ensure that Duke Energy is held responsible for any environmental impacts caused at their coal ash facilities,” Bridget Munger, a spokeswoman for the agency, said in an email.

Pete Harrison, a staff attorney at the environmental law firm Earthjustice, went to the site of the spill Friday and traveled on the Cape Fear River by boat along with a member of the clean-water advocacy group Waterkeeper Alliance. He said water from Lake Sutton was “pouring out” into the river at several points.

Harrison said he and his colleagues saw plumes of water containing coal ash particles, some floating on the surface and some underneath. “These swirling plumes went on for miles, and we watched them form as they poured out of the lake,” he said.

Coal ash is what is left over after coal is burned in a power plant, and it contains heavy metals including arsenic, lead, mercury and chromium. The Sutton plant switched from coal to natural gas years ago, but the waste remains at the site. Farther inland, the company’s Lee power plant has three pits containing coal ash and covered earth and trees; heavy rains washed coal ash from those sites into the nearby Neuse River.

The issue of leaking coal ash is particularly fraught for Duke Energy. In February 2014, a coal ash pond at its Dan River Steam Station spilled as much as 82,000 tons of waste over roughly 70 miles of the Dan River. Federal prosecutors also revealed Duke Energy had been illegally discharging pollution from coal ash dumps into nearby waterways since at least 2010. In May 2016, Duke Energy settled criminal charges for $102 million. Since then, the company has been moving coal ash from waste ponds to more secure, lined landfills.

The company has tried to distinguish between the types of waste in the coal ash basins. Duke Energy said the waste material that had been found so far in the lake and river was a lighter material known as cenospheres — small glasslike beads aluminum and silica left over after coal combustion. The drone video from North Carolina state regulators also showed cenospheres in the water but the agency said they would probably be caught in vegetation and thus easy to recover.

However, toxic heavier metals often attach themselves to the cenospheres, and environmental groups argue that the distinction is not significant.

Harrison said Friday the material spilling from the Sutton plant’s ash ponds is coated with the kind of toxic metals that pose a serious public health risk.

“Cenospheres are the lightest form of coal ash,” said Harrison, who’s temporarily based in North Carolina. “Just like coal ash, they are also loaded with all these other elements. They’re really no different in that regard.”

Earthjustice sampled cenospheres last week that had spilled from three flooded coal ash pits at Duke Energy’s H.F. Lee Plant near Goldsboro, N.C., Harrison said, as well as from sites in the state after Hurricane Matthew in 2016. In both cases, he said, they tested positive for toxic contaminants.

“For them to say cenospheres are not coal ash,” he said, “is like saying a poodle is not a dog."

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Along With Flooding, Hurricane Florence Unleashes Toxic Coal Ash

The coal industry dumped its toxic waste in the cheapest way possible. Now coal ash pits are leaking and spilling amid flooding from Hurricane Florence.

By Jessica A. Knoblauch | September 21, 2018

Coal ash spilled by Hurricane Florence coats a turtle in Cape Fear River, North Carolina. (Riverkeepers cleaned and released the turtle.)

PETE HARRISON / EARTHJUSTICE

As Hurricane Florence floods the Carolinas, a long-buried coal industry secret is rising to the surface. Across the country, giant pits filled with millions of tons of coal ash — a toxic byproduct of burning coal — are leaking. And in the storm-pummeled Southeast, the toxic waste is spreading with the floodwaters.

Coal ash sites at the Duke Energy H.F. Lee plant in Goldsboro, North Carolina, are actively spilling coal ash into the nearby Neuse River. On Wednesday, during a canoe patrol of the flooded area by Waterkeeper groups and Earthjustice attorney Pete Harrison, the group spotted large amounts of floodwater washing coal ash downstream, as well as large swaths of floating coal ash in stagnant areas. The unprotected berm meant to hold the ash in place was eroding away in dozens of locations.

Coal ash leaks from a breached pond at the L.V. Sutton Power Station outside Wilmington, North Carolina.

WATERKEEPER ALLIANCE/CC BY-NC-ND 2.0

Together, the three Lee coal ash basins hold about 1 million tons of toxic ash that contains heavy metals like arsenic and lead. And they are now completely under water.

But they're not the only coal ash sites failing amid the storm. On Friday, floodwaters breached an earthen dam holding back Sutton Lake, a former cooling reservoir at another Duke Energy site, the L.V. Sutton Power Station in Wilmington, North Carolina. Waters from the lake flooded one of three adjacent coal ash lagoons, and riverkeepers are now seeing coal ash in the nearby Cape Fear River. On Thursday, the company had activated a high-level emergency alert after floodwaters from the river overtopped the lake's earthen dam. And a coal ash landfill under construction at the Sutton plant ruptured last week, spilling enough ash to fill 180 dump trucks.

"These are ongoing spills that will continue until the floodwaters recede," says Harrison, who adds that both spills present a threat to drinking water. "It's mind-boggling that these power companies built their toxic waste dumps right next to flood prone rivers. It means that every time there's a major flood, downstream communities have to worry about being exposed to toxic coal ash — as if they don't already have enough to worry about."

The National Weather Service expects the flooding to worsen over the next few days in the aftermath of Florence.

These incidents are entirely predictable, given that industry chooses to deal with this toxic waste the cheapest way it knows how: by placing these unlined or poorly lined pits next to rivers and in floodplains so that the coal plant doesn't have to travel far to water down its waste. Though this practice is great for the industry's bottom line, it's a disaster waiting to happen for communities unfortunate enough to live next to these waste sites.

"Communities living near coal ash dumps are absorbing all the risk when the sites leak or fail," says Earthjustice attorney and coal ash expert Lisa Evans. "Meanwhile, coal companies like Duke make billions of dollars in profits. The inequity of the situation is apparent, and appalling."

As manmade climate change persists, floods are likely to swamp North Carolina's coal ash sites more often. Since the 1990s, climate change has altered weather patterns so drastically that North Carolina has endured four hurricanes or tropical storms that qualify as 100-year storms.

And coal ash incidents aren't limited to when a hurricane rolls into town. In October 2017, Duke Energy had yet another coal ash spill at one of its sites near the city of Gaffney, South Carolina, after 3.74 inches of rain. And the infamous TVA Kingston spill in 2008, which released more than a billion gallons of coal ash and devastated the community of Harriman, Tennessee, occurred in the middle of what was otherwise a cold and dry December night.

Matthew Starr, a lower Neuse riverkeeper, takes a sample of water from the flooded area by the Duke Energy H.F. Lee plant.

Environmentalists and public safety advocates have pushed the EPA for decades to strengthen regulations on these ticking time bombs. In 2015, we made some headway after the EPA created its first-ever regulations on coal ash. Thanks to the 2015 rule, which required utilities nationwide to test the water near their coal ash sites, we're now seeing confirmation of what we've suspected all along: Coal ash sites are leaking pretty much everywhere we look, rain or shine, including in states like Oklahoma and Indiana.

But the new rules didn't go far enough. Among other things, the government failed to adequately regulate unlined and poorly lined ash pits. The agency also improperly exempted coal ash ponds at closed coal-fired power plants from regulation. The three submerged and spilling Lee basins are currently exempted under the rule.

Earthjustice, on behalf of public interest groups, sued the EPA over these failings. In August, an appeals court agreed with us, ordering the EPA to revise the 2015 rule to adequately address the health and environmental threats from these coal ash sites. The judges' order also requires the EPA to close unlined ponds before utilities determine they are leaking — a decision with huge implications given that about 95 percent of the nation's nearly 1,000 ash ponds are unlined.

Coal ash leaks into the Neuse River at the Duke Energy H.F. Lee plant in Goldsboro, North Carolina.

PHOTO COURTESY OF RIVERKEEPER

As communities across the Carolinas brace for more river flooding following Hurricane Florence, we are just beginning to see the extent of the devastation the storm has caused. The Southeast alone has dozens of coal ash sites in Georgia, South Carolina, North Carolina, Virginia and Maryland. Many of them are right in the path of Florence. Only time will tell how many of these sites are ultimately affected by the floods.

Meanwhile, we'll continue to work within the courts to force government agencies to enact stronger protections for coal ash to protect our communities — particularly communities of color and low-income communities that are disproportionately affected. Earthjustice, alongside our partners and allies, has long fought to get coal ash properly regulated. We're not stopping now.

Tags: Clean Energy, Coal, Coal Ash

Hurricane Florence Brings Another Hog Waste Flood to North Carolina

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Serving as President of Earthjustice Has Been the Greatest Honor of My Life

Senior Staff Writer

JESSICA A. KNOBLAUCH

Jessica is a former award-winning journalist. She enjoys wild places and dispensing justice, so she considers her job here to be a pretty amazing fit.

Learn more about Jessica.

The following are attachments to the testimony of Mark Hutson.

ATTACHMENT 5

Prepared for
Dynegy Midwest Generation, LLC
Document type
2019 Annual Groundwater Monitoring and Corrective Action Report
Date
January 31, 2020

2019 ANNUAL GROUNDWATER MONITORING AND CORRECTIVE ACTION REPORT

BALDWIN BOTTOM ASH POND, BALDWIN ENERGY COMPLEX

RAMBOLL Bright ideas. Sustainable change.

2019 ANNUAL GROUNDWATER MONITORING AND CORRECTIVE ACTION REPORT BALDWIN BOTTOM ASH POND, BALDWIN ENERGY COMPLEX

Project name	**Baldwin Energy Complex**
Project no.	**72751**
Recipient	**Dynegy Midwest Generation, LLC**
Document type	**Annual Groundwater Monitoring and Corrective Action Report**
Version	**FINAL**
Date	**January 31, 2020**
Prepared by	**Kristen L. Theesfeld**
Checked by	**Jacob J. Walczak**
Approved by	**Eric J. Tlachac**
Description	**Annual Report in Support of the CCR Rule Groundwater Monitoring Program**

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CONTENTS

TABLES

FIGURES

APPENDICES

ACRONYMS AND ABBREVIATIONS

ASD	Alternate Source Demonstration
BAP	Bottom Ash Pond
CCR	Coal Combustion Residuals
GWPS	Groundwater Protection Standard
SAP	Sampling and Analysis Plan
SSI	Statistically Significant Increase
SSL	Statistically Significant Level

EXECUTIVE SUMMARY

This report has been prepared to provide the information required by Title 40 of the Code of Federal Regulations (40 C.F.R.) § 257.90(e) for Baldwin Bottom Ash Pond (BAP) located at Baldwin Energy Complex near Baldwin, Illinois.

Groundwater is being monitored at Baldwin BAP in accordance with the Assessment Monitoring Program requirements specified in 40 C.F.R. § 257.95.

No changes were made to the monitoring system in 2019 (no wells were installed or decommissioned).

The following Statistically Significant Levels (SSLs) of 40 C.F.R. Part 257 Appendix IV parameters were determined during one or more sampling events in 2019:

- Lithium at well MW-370

Alternate Source Demonstrations (ASDs) were completed for the SSLs referenced above and Baldwin BAP remains in the Assessment Monitoring Program.

1. INTRODUCTION

This report has been prepared by Ramboll on behalf of Dynegy Midwest Generation, LLC, to provide the information required by 40 C.F.R.§ 257.90(e) for Baldwin BAP located at Baldwin Energy Complex near Baldwin, Illinois.

In accordance with 40 C.F.R. § 257.90(e), the owner or operator of a Coal Combustion Residuals (CCR) unit must prepare an Annual Groundwater Monitoring and Corrective Action Report for the preceding calendar year that documents the status of the Groundwater Monitoring and Corrective Action Program for the CCR unit, summarizes key actions completed, describes any problems encountered, discusses actions to resolve the problems, and projects key activities for the upcoming year. At a minimum, the Annual Report must contain the following information, to the extent available:

1. A map, aerial image, or diagram showing the CCR unit and all background (or upgradient) and downgradient monitoring wells, to include the well identification numbers, that are part of the groundwater monitoring program for the CCR unit.
2. Identification of any monitoring wells that were installed or decommissioned during the preceding year, along with a narrative description of why those actions were taken.
3. In addition to all the monitoring data obtained under §§ 257.90 through 257.98, a summary including the number of groundwater samples that were collected for analysis for each background and downgradient well, the dates the samples were collected, and whether the sample was required by the Detection Monitoring or Assessment Monitoring Programs.
4. A narrative discussion of any transition between monitoring programs (e.g., the date and circumstances for transitioning from Detection Monitoring to Assessment Monitoring in addition to identifying the constituent(s) detected at a Statistically Significant Increase relative to background levels).
5. Other information required to be included in the Annual Report as specified in §§ 257.90 through 257.98.

This report provides the required information for Baldwin BAP for calendar year 2019.

2. MONITORING AND CORRECTIVE ACTION PROGRAM STATUS

No changes have occurred to the Monitoring Program status in calendar year 2019, and Baldwin BAP remains in the Assessment Monitoring Program in accordance with 40 C.F.R. § 257.95.

3. KEY ACTIONS COMPLETED IN 2019

The Assessment Monitoring Program is summarized in Table A. The groundwater monitoring system, including the CCR unit and all background and downgradient monitoring wells, is presented in Figure 1. No changes were made to the monitoring system in 2019 (no wells were installed or decommissioned). In general, one groundwater sample was collected from each background and downgradient well during each monitoring event. All samples were collected and analyzed in accordance with the Sampling and Analysis Plan (SAP) (NRT/OBG, 2017a). All monitoring data obtained under 40 C.F.R. §§ 257.90 through 257.98 (as applicable) in 2019 are presented in Tables 1 and 2. Analytical data were evaluated in accordance with the Statistical Analysis Plan (NRT/OBG, 2017b) to determine any SSLs of Appendix IV parameters over Groundwater Protection Standards (GWPSs).

Statistical background values are provided in Table 3 and GWPSs in Table 4.

Analytical results for the June and September 2018 sampling events were provided in the 2018 Annual Groundwater Monitoring and Corrective Action Report.

Potential alternate sources were evaluated as outlined in the 40 C.F.R. § 257.95(g)(3)(ii). ASDs were completed and certified by a qualified professional engineer. The dates the ASDs were completed are provided in Table A. The ASDs completed in 2019 are included in Appendix A.

Table A – 2018-2019 Assessment Monitoring Program Summary

Sampling Dates	Analytical Data Receipt Date	Parameters Collected	SSL(s)	SSL(s) Determination Date	ASD Completion Date
June 26-27, 2018	August 22, 2018	Appendix III Appendix IV	NA	NA	NA
September 26, 2018	October 24, 2018	Appendix III Appendix IV Detected [1]	Lithium (MW-370)	January 7, 2019	April 8, 2019
March 19-20, 2019	April 15, 2019	Appendix III Appendix IV	Lithium (MW-370)	July 15, 2019	October 14, 2019
September 24-25, 2019	October 24, 2019	Appendix III Appendix IV Detected [1]	NA	TBD	TBD

Notes:

NA: Not Applicable
TBD: To Be Determined
1. To confirm SSIs, as allowed by the Statistical Analysis Plan, groundwater samples were collected and analyzed for Appendix III parameters initially detected at concentrations greater than statistical background values in the preceding sampling event.

4. PROBLEMS ENCOUNTERED AND ACTIONS TO RESOLVE THE PROBLEMS

No problems were encountered with the Groundwater Monitoring Program during 2019. Groundwater samples were collected and analyzed in accordance with the SAP (NRT/OBG, 2017a), and all data were accepted.

5. KEY ACTIVITIES PLANNED FOR 2020

The following key activities are planned for 2020:

- Continuation of the Assessment Monitoring Program with semi-annual sampling scheduled for the first and third quarters of 2020.
- Complete evaluation of analytical data from the downgradient wells, using GWPSs to determine whether an SSL of Appendix IV parameters has occurred.
- If an SSL is identified, potential alternate sources (i.e., a source other than the CCR unit caused the SSL or that that SSL resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality) will be evaluated.
  - If an alternate source is demonstrated to be the cause of the SSL, a written demonstration will be completed within 90 days of SSL determination and included in the 2020 Annual Groundwater Monitoring and Corrective Action Report.
  - If an alternate source(s) is not identified to be the cause of the SSL, the applicable requirements of 40 C.F.R. §§ 257.94 through 257.98 (e.g., assessment of corrective measures) as may apply in 2020 will be met, including associated recordkeeping/notifications required by 40 C.F.R. §§ 257.105 through 257.108.

6. REFERENCES

Natural Resource Technology, an OBG Company (NRT/OBG), 2017a. Sampling and Analysis Plan, Baldwin Bottom Ash Pond, Baldwin Energy Complex, Baldwin, Illinois, Project No. 2285, Revision 0, October 17, 2017.

Natural Resource Technology, an OBG Company (NRT/OBG), 2017b. Statistical Analysis Plan, Baldwin Energy Complex, Havana Power Station, Hennepin Power Station, Wood River Power Station, Dynegy Midwest Generation, LLC, October 17, 2017.

TABLES

TABLE 1.
2019 ANALYTICAL RESULTS - GROUNDWATER ELEVATION AND APPENDIX III PARAMETERS
2019 ANNUAL GROUNDWATER MONITORING AND CORRECTIVE ACTION REPORT
BALDWIN ENERGY COMPLEX
UNIT ID 601 - BALDWIN BOTTOM ASH POND
BALDWIN, ILLINOIS
ASSESSMENT MONITORING PROGRAM

Well Identification Number	Latitude (Decimal Degrees)	Longitude (Decimal Degrees)	Date & Time Sampled	Depth to Groundwater (ft)[1]	Groundwater Elevation (ft NAVD88)	40 C.F.R. Part 257 Appendix III						
						Boron, total (mg/L) 6020A[2]	Calcium, total (mg/L) 6020A[2]	Chloride, total (mg/L) 9251[2]	Fluoride, total (mg/L) 9214[2]	pH (field) (S.U.) SM 4500 H+B[2]	Sulfate, total (mg/L) 9036[2]	Total Dissolved Solids (mg/L) SM 2540C[2]
Background / Upgradient Monitoring Wells												
MW-304	38.188332	-89.853441	3/20/2019 15:03	9.33	446.16	1.82	13.7	148	1.88	7.7	177	1390
			9/25/2019 13:11	9.30	446.19	1.84	18.4	152	1.74	7.9	169	1350
MW-306	38.201117	-89.846747	3/20/2019 14:16	16.98	436.19	0.174	50.4	62	0.65	11.4	32	330
			9/25/2019 14:22	18.10	435.07	0.166	46.0	62	0.59	11.0	37	318
Downgradient Monitoring Wells												
MW-356	38.198963	-89.869578	3/19/2019 10:51	2.65	424.95	2.12	11.7	31	2.18	7.8	43	678
			9/24/2019 10:32	3.02	424.58	2.04	11.6	29	2.00	7.7	38	644
MW-369	38.196986	-89.870258	3/19/2019 10:09	19.44	403.27	1.96	70.7	92	1.48	7.3	98	732
			9/24/2019 9:50	13.10	409.61	0.948	85.0	101	1.08	6.7	90	788
MW-370	38.195603	-89.869669	3/19/2019 11:30	17.50	403.35	2.01	46.7	1280	3.45	7.7	224	2950
			9/24/2019 11:10	18.98	401.87	1.95	47.0	1290	3.00	7.5	237	2830
MW-382	38.194540	-89.868044	3/19/2019 12:26	15.42	415.77	1.86	21.5	36	3.30	7.6	426	1180
			9/24/2019 12:10	16.23	414.96	1.78	20.5	34	2.85	7.7	388	1150

[O: RAB 12/23/19, C: KLT 12/23/19]

Notes:
40 C.F.R. = Title 40 of the Code of Federal Regulations
ft = foot/feet
mg/L = milligrams per liter
NAVD88 = North American Vertical Datum of 1988
S.U. = Standard Units
< = concentration is less than the concentration shown, which corresponds to the reporting limit for the method; estimated concentrations below the reporting limit and associated qualifiers are not provided since not utilized in statistics to determine Statistically Significant Increases (SSIs) over background.
[1]All depths to groundwater were measured on the first day of the sampling event.
[2]4-digit numbers represent SW-846 analytical methods.

TABLE 2.
2019 ANALYTICAL RESULTS - APPENDIX IV PARAMETERS
2019 ANNUAL GROUNDWATER MONITORING AND CORRECTIVE ACTION REPORT
BALDWIN ENERGY COMPLEX
UNIT ID 601 - BALDWIN BOTTOM ASH POND
BALDWIN, ILLINOIS
ASSESSMENT MONITORING PROGRAM

				40 C.F.R. Part 257 Appendix IV														
Well Identification Number	Latitude (Decimal Degrees)	Longitude (Decimal Degrees)	Date & Time Sampled	Antimony, total (mg/L) 6020A[1]	Arsenic, total (mg/L) 6020A[1]	Barium, total (mg/L) 6020A[1]	Beryllium, total (mg/L) 6020A[1]	Cadmium, total (mg/L) 6020A[1]	Chromium, total (mg/L) 6020A[1]	Cobalt, total (mg/L) 6020A[1]	Fluoride, total (mg/L) 6020A[1]	Lead, total (mg/L) 6020A[1]	Lithium, total (mg/L) 6020A[1]	Mercury, total (mg/L) 7470A[1]	Molybdenum, total (mg/L) 6020A[1]	Radium 226/228, Combined (pCi/L) 903/904[1]	Selenium, total (mg/L) 6020A[1]	Thallium, total (mg/L) 6020A[1]
Background / Upgradient Monitoring Wells																		
MW-304	38.188332	-89.853441	3/20/2019 15:03	<0.0010	0.0029	0.0214	<0.0010	<0.0010	<0.0015	<0.0010	1.88	<0.0010	0.0833	<0.00020	0.0019	0.55	<0.0010	<0.0020
			9/25/2019 13:11[2]	<0.0010	0.0017	0.0211	<0.0010	<0.0010	<0.0015	<0.0010	1.74	<0.0010	0.0836	<0.00020	0.0017	0.42	<0.0010	<0.0020
MW-306	38.201117	-89.846747	3/20/2019 14:16	<0.0010	0.0030	0.0192	<0.0010	<0.0010	<0.0015	<0.0010	0.65	<0.0010	0.0143	<0.00020	0.0299	0.74	<0.0010	<0.0020
			9/25/2019 14:22[2]	<0.0010	0.0021	0.0150	<0.0010	<0.0010	<0.0015	<0.0010	0.59	<0.0010	0.0133	<0.00020	0.0267	0.36	<0.0010	<0.0020
Downgradient Monitoring Wells																		
MW-356	38.198963	-89.869578	3/19/2019 10:51	<0.0010	0.0011	0.0322	<0.0010	<0.0010	<0.0015	<0.0010	2.18	<0.0010	0.0578	<0.00020	<0.0015	0.19	<0.0010	<0.0020
			9/24/2019 10:32[2]	NA	<0.0010	0.0307	NA	NA	<0.0015	NA	2.00	NA	0.0580	NA	<0.0015	0.10	NA	NA
MW-369	38.196986	-89.870258	3/19/2019 10:09	<0.0010	0.0021	0.0562	<0.0010	<0.0010	<0.0015	<0.0010	1.48	<0.0010	0.0382	<0.00020	0.0263	0.34	<0.0010	<0.0020
			9/24/2019 9:50[2]	NA	0.0059	0.0849	NA	NA	<0.0015	NA	1.08	NA	0.0259	NA	0.0186	0.84	NA	NA
MW-370	38.195603	-89.869669	3/19/2019 11:30	<0.0010	0.0015	0.0449	<0.0010	<0.0010	<0.0015	<0.0010	3.45	<0.0010	0.147	<0.00020	0.0238	0.61	<0.0010	<0.0020
			9/24/2019 11:10[2]	NA	<0.0010	0.0424	NA	NA	<0.0015	NA	3.00	NA	0.149	NA	0.0188	0.75	NA	NA
MW-382	38.194540	-89.868044	3/19/2019 12:26	<0.0010	0.0012	0.0170	<0.0010	<0.0010	0.0021	<0.0010	3.30	<0.0010	0.0625	<0.00020	0.0019	0.16	<0.0010	<0.0020
			9/24/2019 12:10[2]	NA	0.0012	0.0221	NA	NA	0.0044	NA	2.85	NA	0.0623	NA	0.0025	0.51	NA	NA

[O: RAB 12/23/19, C: KLT 12/23/19]

Notes:
40 C.F.R. = Title 40 of the Code of Federal Regulations
mg/L = milligrams per liter
NA = Not Analyzed
pCi/L = picoCuries per liter
< = concentration is less than concentration shown, which corresponds to the reporting limit for the method; estimated concentrations below the reporting limit and associated qualifiers are not provided since not utilized in statistics to determine Statistically Significant Levels (SSLs) over Groundwater Protection Standards.
[1]4-digit numbers represent SW-846 analytical methods and 3-digit numbers represent Clean Water Act analytical methods.
[2]Only the parameters detected during the previous sampling events were analyzed during this sampling event, in accordance with 40 C.F.R. § 257.95(d)(1).

TABLE 3.
STATISTICAL BACKGROUND VALUES
2019 ANNUAL GROUNDWATER MONITORING AND CORRECTIVE ACTION REPORT
BALDWIN ENERGY COMPLEX
UNIT ID 601 - BALDWIN BOTTOM ASH POND
BALDWIN, ILLINOIS
ASSESSMENT MONITORING PROGRAM

Parameter	Statistical Background Value (UPL)
40 C.F.R. Part 257 Appendix III	
Boron (mg/L)	2.11
Calcium (mg/L)	33.5
Chloride (mg/L)	155
Fluoride (mg/L)	1.98
pH (S.U.)	7.8 / 11.2
Sulfate (mg/L)	200
Total Dissolved Solids (mg/L)	1360

[O: RAB 12/22/19, C: KLT 12/23/19]

Notes:
40 C.F.R. = Title 40 of the Code of Federal Regulations
mg/L = milligrams per liter
S.U. = Standard Units
UPL = Upper Prediction Limit

TABLE 4.
GROUNDWATER PROTECTION STANDARDS
2019 ANNUAL GROUNDWATER MONITORING AND CORRECTIVE ACTION REPORT
BALDWIN ENERGY COMPLEX
UNIT ID 601 - BALDWIN BOTTOM ASH POND
BALDWIN, ILLINOIS
ASSESSMENT MONITORING PROGRAM

Parameter	Groundwater Protection Standard[1]
40 C.F.R. Part 257 Appendix IV	
Antimony (mg/L)	0.006
Arsenic (mg/L)	0.032
Barium (mg/L)	2
Beryllium (mg/L)	0.004
Cadmium (mg/L)	0.005
Chromium (mg/L)	0.10
Cobalt (mg/L)	0.006
Fluoride (mg/L)	4
Lead (mg/L)	0.015
Lithium (mg/L)	0.069
Mercury (mg/L)	0.002
Molybdenum (mg/L)	0.10
Radium 226+228 (pCi/L)	5
Selenium (mg/L)	0.05
Thallium (mg/L)	0.002

[O: RAB 12/22/19, C: KLT 12/23/19]

Notes:
40 C.F.R. = Title 40 of the Code of Federal Regulations
mg/L = milligrams per liter
pCi/L = picoCuries per liter
[1]Groundwater Protection Standard is the higher of the Maximum Contaminant Level / Health-Based Level or background.

FIGURES

DOWNGRADIENT MONITORING WELL LOCATION
UPGRADIENT MONITORING WELL LOCATION
CCR MONITORED UNIT

0 400 800 Feet

MONITORING WELL LOCATION MAP
BALDWIN BOTTOM ASH POND
UNIT ID:601

2019 ANNUAL GROUNDWATER MONITORING AND CORRECTIVE ACTION REPORT
VISTRA CCR RULE GROUNDWATER MONITORING
BALDWIN ENERGY COMPLEX
BALDWIN, ILLINOIS

FIGURE 1

O'BRIEN & GERE ENGINEERS, INC.
A RAMBOLL COMPANY

RAMBOLL

PROJECT: 166000XXXX | DATED: 1/13/2020 | DESIGNER: GALARNMC

APPENDIX A
ALTERNATE SOURCE DEMONSTRATIONS

40 C.F.R. § 257.95(g)(3)(ii): ALTERNATE SOURCE DEMONSTRATION
BALDWIN BOTTOM ASH POND
APRIL 8, 2019

April 8, 2019

This alternate source demonstration has been prepared on behalf of Dynegy Midwest Generation, LLC (DMG) by OBG, part of Ramboll (OBG) to provide pertinent information pursuant to 40 CFR § 257.95(g)(3)(ii) for the Baldwin Bottom Ash Pond (BAP) located at Baldwin Energy Complex near Baldwin, Illinois.

Initial background groundwater monitoring consisting of a minimum of eight samples as required under 40 CFR § 257.94(b) was initiated in December 2015 and completed prior to October 17, 2017. Comparison of background groundwater quality with concentrations of parameters in downgradient monitoring wells observed during the November 2017 Detection Monitoring Program sampling event identified a statistically significant increase (SSI) for one or more 40 CFR Part 257 Appendix III parameters at Baldwin BAP. Consequently, and in accordance with 40 CFR § 257.94(e) and 40 CFR § 257.95, an assessment monitoring program was established by April 9, 2018 for the Baldwin BAP.

The first Assessment Monitoring sampling event was completed on June 26, 2018 and June 27, 2018. As stipulated in 40 CFR § 257.95(d)(1), all wells were resampled on September 26, 2018 for all Appendix III parameters and the Appendix IV parameters detected during the first Assessment Monitoring sampling event. Groundwater data collected from the first Assessment Monitoring sampling event and resampling event are available in the 2018 Annual Groundwater Monitoring and Corrective Action Report for Baldwin Bottom Ash Pond completed January 31, 2019 (OBG, 2019). Analytical data from all sampling events from December 2015 through the resampling event were evaluated in accordance with the statistical analysis plan (NRT/OBG, 2017) to determine any SSIs of Appendix III parameters over background concentrations or statistically significant levels (SSLs) of Appendix IV parameters over Groundwater Protection Standards (GWPSs). That evaluation identified SSLs at downgradient monitoring wells as follows:

- Lithium at well MW-370

Per 40 CFR § 257.95(g)(3)(ii), the owner or operator of a CCR unit may complete within 90 days from the date of an SSL determination a written demonstration that a source other than the CCR unit caused the SSL, or that the SSL resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality ("alternate source demonstration"). Pursuant to 40 CFR § 257.95(g)(3)(ii), the following demonstrates that sources other than the Baldwin BAP were the cause of the SSL listed above. This alternate source demonstration (ASD) was completed within 90 days of determination of the SSLs (January 7, 2019) as required by 40 CFR § 257.95(g)(3)(ii).

ALTERNATE SOURCE DEMONSTRATION: LINES OF EVIDENCE

This ASD is based on the following lines of evidence (LOE):

1. The BAP water has a different ionic composition than groundwater.
2. Lithium concentrations in the BAP water are lower than the concentrations observed in groundwater.

These lines of evidence are described and supported in greater detail below. Monitoring wells and BAP water sample locations are shown Figure 1 (attached).

LOE #1: THE BAP WATER HAS A DIFFERENT IONIC COMPOSITION THAN GROUNDWATER.

Stiff diagrams graphically represent ionic composition of aqueous solutions. Figure 2 shows a series of Stiff diagrams that display the ionic compositions of the BAP water and groundwater from background and downgradient monitoring wells in the monitoring system. Polygons with similar shapes represent solutions with similar ionic compositions, whereas polygons with different shapes indicate solutions with dissimilar ionic compositions.

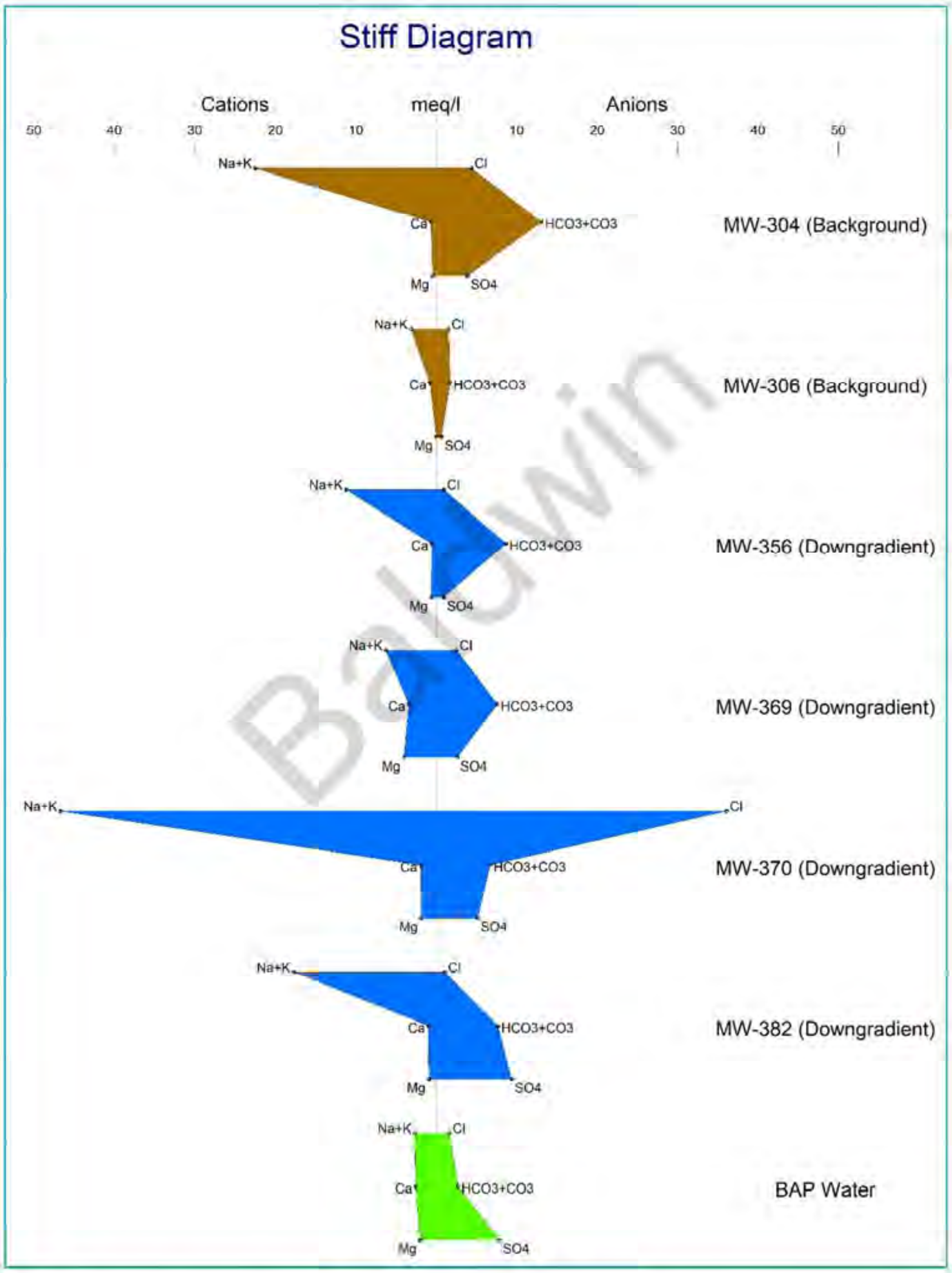


Figure 2. Stiff diagram showing ionic composition of samples of BAP background and downgradient groundwater and BAP water.

The ionic compositions of the BAP water and groundwater represented by Figure 2 are discussed in more detail below.

- The dominant cations in BAP groundwater at background and downgradient monitoring wells are sodium-potassium.
- Figure 2 indicates that MW-369 has a relatively higher proportion of calcium and magnesium cations than other wells in the groundwater monitoring system, although sodium-potassium cations are still dominant.
- The polygon associated with the BAP water sample in Figure 2 is relatively flat on the left side indicating there is no overly dominant cation.
- The dominant anions in most BAP monitoring wells are carbonate-bicarbonate, with the exceptions of downgradient monitoring well locations MW-370 and MW-382.
- MW-370 is the only location analyzed where the major anions are dominated by chloride, this results in a distinct polygon shape when compared to other sample locations as illustrated in Figure 2.
- The dominant anions at MW-382 are sulfate and carbonate-bicarbonate.
- The dominant anion in the BAP water sample is sulfate.

The Stiff diagrams and analysis of ionic composition in the BAP water sample and groundwater indicate the ionic composition of water at MW-370 is not influenced by the BAP.

LOE #2: LITHIUM CONCENTRATIONS IN THE BAP WATER ARE LOWER THAN THE CONCENTRATIONS OBSERVED IN GROUNDWATER

Lithium concentrations in the BAP water, including samples from BAP water and TPZ-164 bottom ash porewater well (see boring log in Attachment A), are lower than lithium concentrations in groundwater. A time-series for lithium concentrations is provided in Figure 3 below.

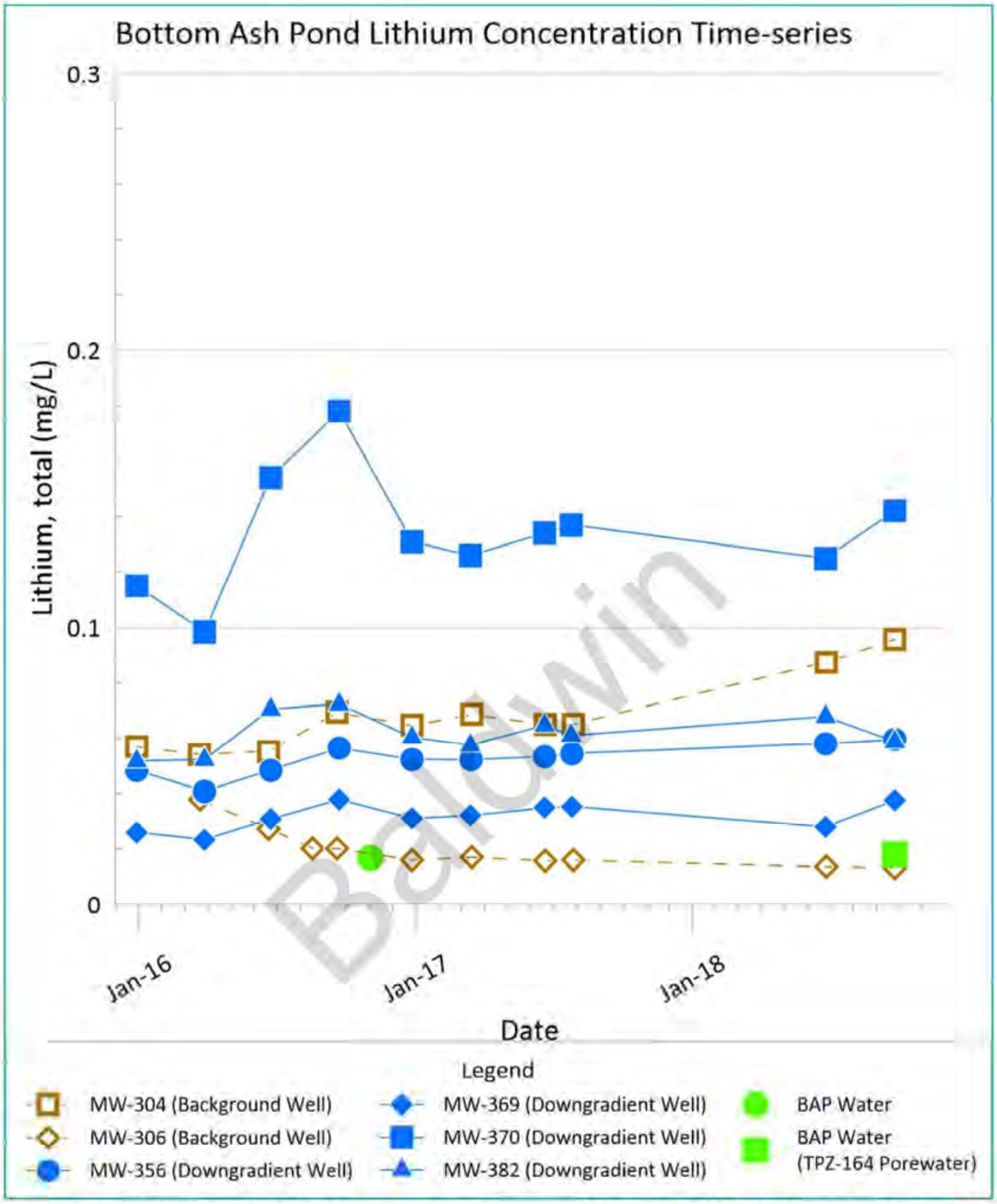


Figure 3. Lithium Concentration Time-series for groundwater samples from the BAP monitoring system and BAP water.

The following observations can be made from Figure 3:

- BAP water ranges from 0.0167 to 0.0182 mg/L of lithium.
- Groundwater from downgradient wells MW-356, MW-369, MW-370 and MW-382 has one to ten times greater lithium concentrations than the maximum lithium concentration (0.0182 mg/L) observed in BAP water.
- Groundwater from background well MW-304 has three to five times greater lithium concentrations than the maximum lithium concentration (0.0182 mg/L) observed in BAP water.

If the BAP were the source of lithium in groundwater, BAP water concentrations would be anticipated to be higher than concentrations of lithium in groundwater monitoring wells. Therefore, the BAP is not the source of the lithium observed in groundwater samples. Background lithium concentrations at MW-304 were also shown to be significantly higher than water in the pond, indicating lithium concentrations are either naturally occurring due to geochemical variations within the Uppermost Aquifer or from upgradient anthropogenic sources.

Based on these two lines of evidence, it has been demonstrated that the Baldwin BAP has not caused the SSL in MW-370.

This information serves as the written alternate source demonstration prepared in accordance with 40 CFR § 257.95(g)(3)(ii) that the SSL observed during the assessment monitoring program was not due to the CCR unit, but was from a combination of naturally occurring conditions and potential upgradient anthropogenic impacts. Therefore, a corrective measures assessment is not required and the Baldwin BAP will remain in assessment monitoring.

Attachment A Boring Log for Porewater Well TPZ-164

REFERENCES

Natural Resource Technology, an OBG Company, 2017a, Statistical Analysis Plan, Baldwin Energy Complex, Havana Power Station, Hennepin Power Station, Wood River Power Station, Dynegy Midwest Generation, LLC, October 17, 2017.

O'Brien & Gere Engineers, Inc. (OBG), 2019, 2018 Annual Groundwater Monitoring and Corrective Action Report, Baldwin Bottom Ash Pond – CCR Unit ID 601, Baldwin Energy Complex, Dynegy Midwest Generation, LLC, January 31, 2019.

I, Eric J. Tlachac, a qualified professional engineer in good standing in the State of Illinois, certify that the information in this report is accurate as of the date of my signature below. The content of this report is not to be used for other than its intended purpose and meaning, or for extrapolations beyond the interpretations contained herein.

Eric J. Tlachac
Qualified Professional Engineer
062-063091
Illinois
OBG, part of Ramboll
Date: April 8, 2019

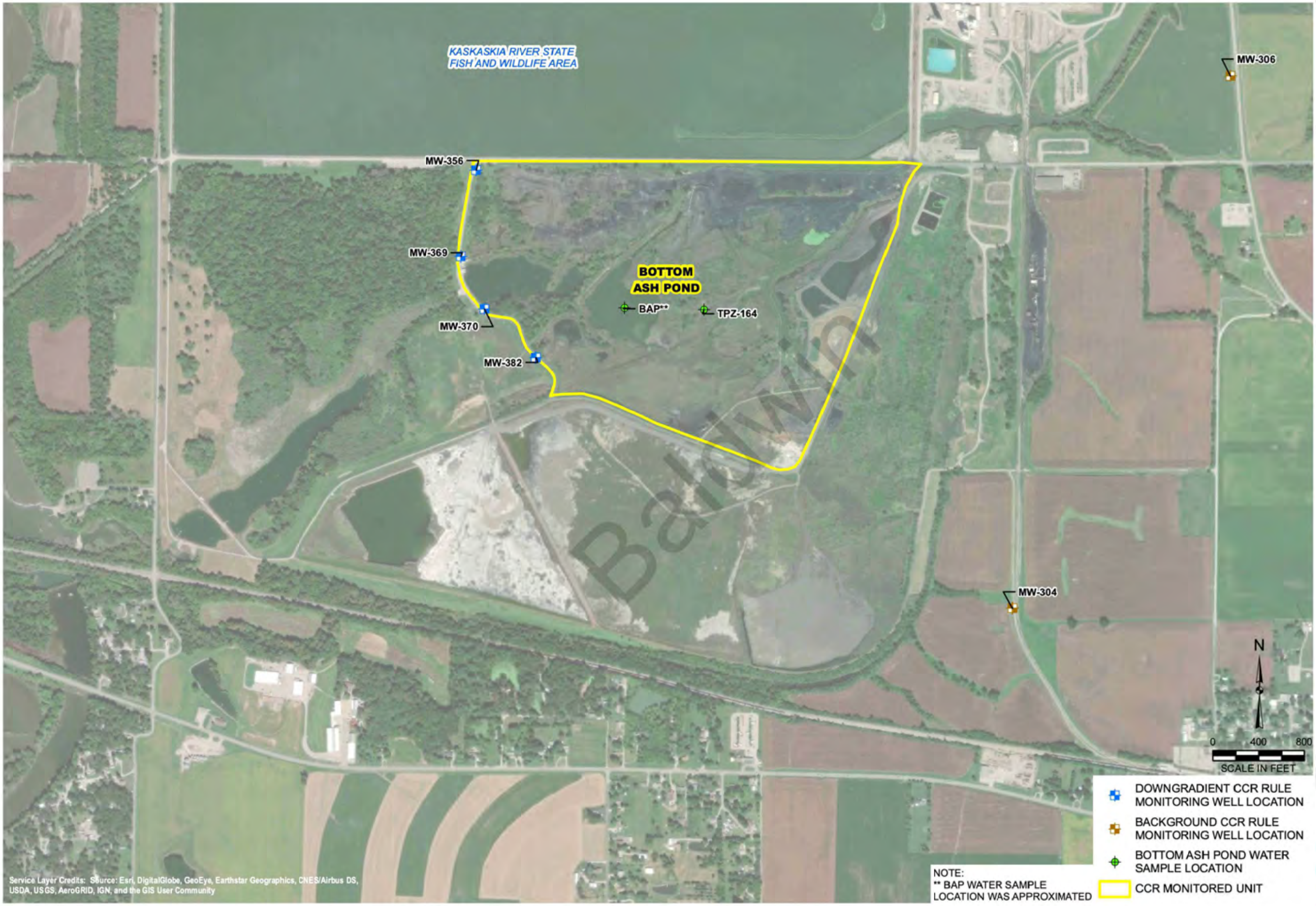
LICENSED PROFESSIONAL ENGINEER
ERIC J. TLACHAC
062-063091
STATE OF ILLINOIS

I, Jacob J. Walczak, a professional geologist in good standing in the State of Illinois, certify that the information in this report is accurate as of the date of my signature below. The content of this report is not to be used for other than its intended purpose and meaning, or for extrapolations beyond the interpretations contained herein.

Jacob J. Walczak
Professional Geologist
196-001473
Illinois
OBG, part of Ramboll
Date: April 8, 2019

LICENSED PROFESSIONAL GEOLOGIST
JACOB J. WALCZAK
196-001473
ILLINOIS

Figures



MONITORING WELL AND
BOTTOM ASH POND WATER SAMPLE LOCATION MAP
BALDWIN BOTTOM ASH POND
ALTERNATE SOURCE DEMONSTRATION
BALDWIN ENERGY COMPLEX
BALDWIN, ILLINOIS

DRAWN BY/DATE: SDS 3/25/19
REVIEWED BY/DATE: JJW 3/26/19
APPROVED BY/DATE: JJW 3/27/19

PROJECT NO: 70093

FIGURE NO: 1

OBG Part of Ramboll

Attachment A

Boring Log for Porewater Well TPZ-164

KELRON ENVIRONMENTAL
Incorporated

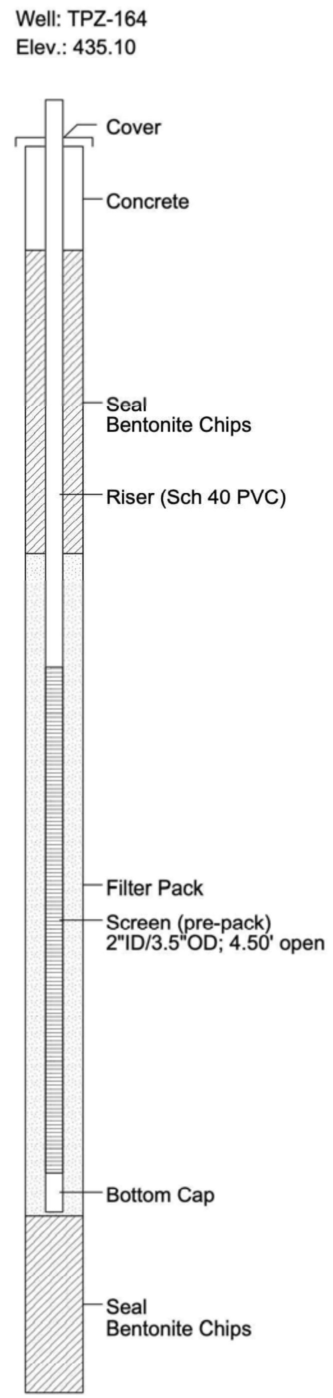
LOG OF PROBEHOLE TPZ-164

Phase II Hydrogeologic Investigation
Baldwin Energy Complex
Dynegy Midwest Generation, Inc.

Date Completed	: 08/26/2013	Driller	: John Gates
Hole Diameter	: 8 1/2" OD / 4 1/4" ID	Geologist	: Stuart Cravens (Kelron)
Drilling Method	: HSA (CME-55LC)	Ground Elevation	: 432.50
Sampling Method	: Split Spoon / Shelby Tube	Casing (MP) Elevation	: 435.10
Drilling Company	: Bulldog Drilling, LLC	X,Y Coordinates	: 2383909, 556829

Depth in Feet	DESCRIPTION	Surf. Elev. 432.50	Samples	Blow Count	Recovery inches	Qp TSF	USCS	GRAPHIC
0	FILL - Bottom Ash, coarse, black (10YR 2/1), dry							
1								
2		430						
3	- moist <Shelby Tube Sample ST164-5 @ 3-5'> grain size analysis (Ash): 50% Sand, 42.9% Silt, 7.1% Clay	429						
4			1		17/24		AR	
	- wet	428						
5		427						
6		426						
7		425						
8		424		3				
9	CLAY (lean), stiff, medium to high plasticity, dark gray (10YR 4/1), moist - @8.9' - light yellowish brown (10YR 6/4) with <10% light gray mottling - @9.3' - gray (10YR 6/1) with 25-50% brownish-yellow mottling (10YR 6/6)	423	2	3 5	18/18		CL	
10	- light olive brown <Shelby Tube Sample ST164-12 @ 10-12'> grain size analysis: 7.2% Sand, 62.2% Silt, 30.6% Clay	422						
11		421	3		23/24		CL	
12	END BOREHOLE AT 10.3 FEET BLS END Split-Spoon Sampling at 12 feet BLS	420						

- 419



11-08-2013 C:\Consulting A\Power Plants\Baldwin\Baldwin 2013 Hydrogeologic Study\Field Work Phase\Boring Logs\BEC164.BOR

40 C.F.R. § 257.95(g)(3)(ii): ALTERNATE SOURCE DEMONSTRATION
BALDWIN BOTTOM ASH POND
OCTOBER 14, 2019

October 14, 2019

Title 40 of the Code of Federal Regulations (C.F.R.) § 257.95(g)(3)(ii) allows the owner or operator of a Coal Combustion Residuals (CCR) unit 90 days from the date of determination of Statistically Significant Levels (SSLs) over Groundwater Protection Standards (GWPSs) of groundwater constituents listed in Appendix IV of 40 C.F.R. Part 257 to complete a written demonstration that a source other than the CCR unit being monitored caused the SSL(s), or that the SSL(s) resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality (Alternate Source Demonstration [ASD]).

This ASD has been prepared on behalf of Dynegy Midwest Generation, LLC (DMG), by O'Brien & Gere Engineers, Inc, part of Ramboll (OBG), to provide pertinent information pursuant to 40 C.F.R. § 257.95(g)(3)(ii) for the Baldwin Bottom Ash Pond (BAP) located near Baldwin, Illinois.

The second Assessment Monitoring sampling event (A2) was completed on March 19-20, 2019 and analytical data were received on April 15, 2019. Analytical data from all sampling events, from December 2015 through A2, were evaluated in accordance with the Statistical Analysis Plan[1] to determine any Statistically Significant Increases (SSIs) of Appendix III parameters over background concentrations or SSLs of Appendix IV parameters over Groundwater Protection Standards (GWPSs). That evaluation identified SSLs at downgradient monitoring wells as follows:

- Lithium at well MW-370

Pursuant to 40 C.F.R. § 257.95(g)(3)(ii), the following demonstrates that sources other than the Baldwin BAP were the cause of the SSL listed above. This ASD was completed by October 14, 2019, within 90 days of determination of the SSLs, as required by 40 C.F.R. § 257.95(g)(3)(ii).

ALTERNATE SOURCE DEMONSTRATION: LINES OF EVIDENCE

This ASD is based on the following lines of evidence (LOE):

1. Lithium concentrations in the BAP porewater are lower than the concentrations observed in groundwater.
2. The BAP porewater has a different ionic composition than groundwater.

These lines of evidence are described and supported in greater detail below. Monitoring wells and the BAP porewater sample location are shown Figure 1 (attached).

LOE #1: LITHIUM CONCENTRATIONS IN THE BAP POREWATER ARE LOWER THAN THE CONCENTRATIONS OBSERVED IN GROUNDWATER

Lithium concentrations in BAP porewater samples collected from TPZ-164 bottom ash porewater well (see boring log in Attachment A) are lower than lithium concentrations in groundwater. A time-series plot of lithium concentrations is provided in Figure 2 below.

[1] Natural Resource Technology, an OBG Company, 2017, Statistical Analysis Plan, Baldwin Energy Complex, Havana Power Station, Hennepin Power Station, Wood River Power Station, Dynegy Midwest Generation, LLC, October 17, 2017.

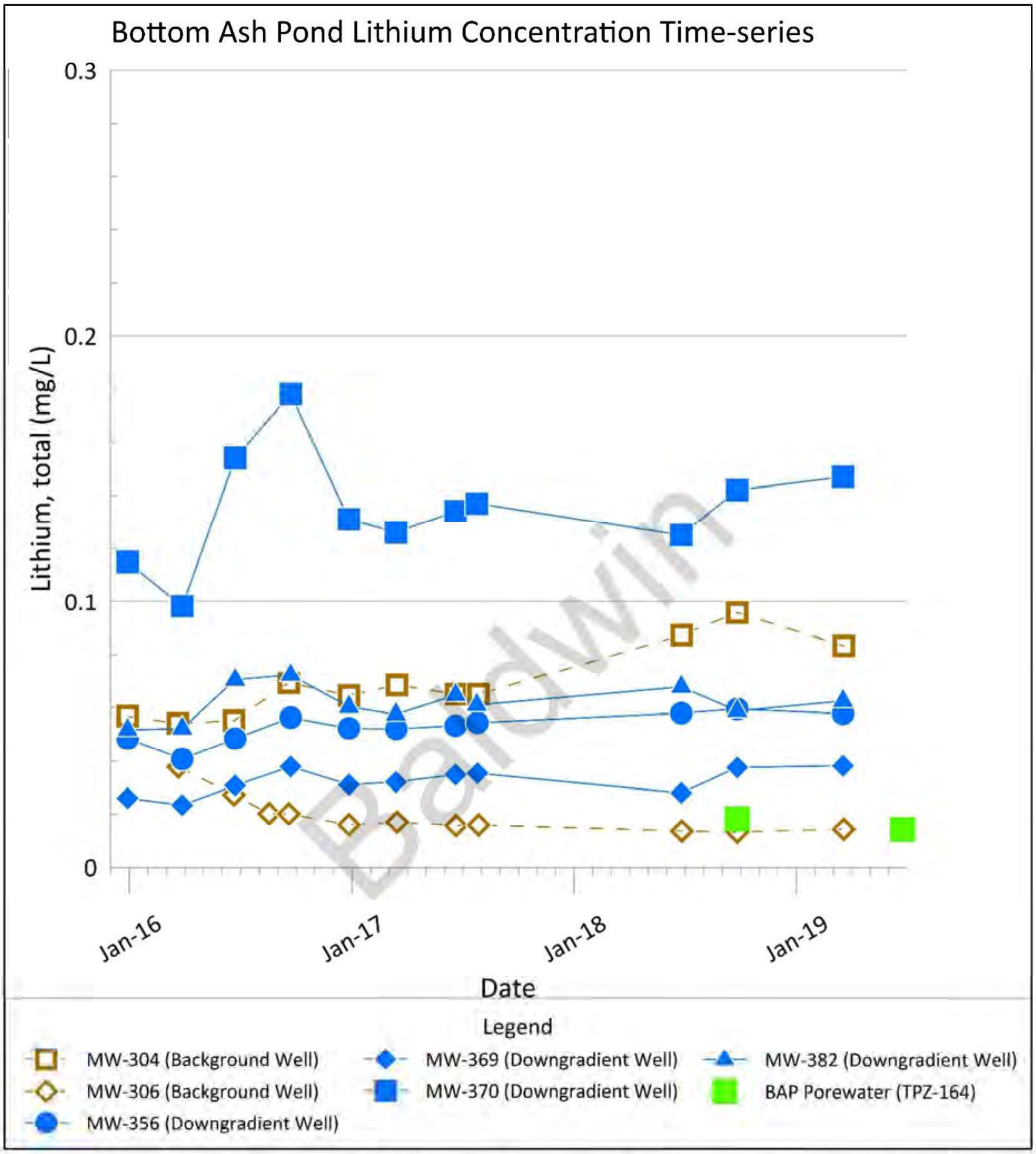


Figure 2. Lithium concentration time-series for background (brown) and downgradient (blue) groundwater samples from the BAP monitoring system, and BAP porewater (green).

The following observations can be made from Figure 2:

- Concentrations of lithium in background wells ranged from 0.0132 to 0.0958 milligrams per liter (mg/L).
- Concentrations of lithium in downgradient wells MW-356, MW-369 and MW-382 ranged from 0.0234 to 0.0723 mg/L, generally within the range of background concentrations.
- Concentrations of lithium in MW-370, where the SSL was identified, ranged from 0.0983 to 0.178 mg/L, above the upper range of lithium concentrations detected in other groundwater monitoring wells.

- Concentrations of lithium in BAP porewater range from 0.0142 to 0.0182 mg/L. These levels of lithium are at or below the lower end of the range of lithium concentrations detected in all groundwater monitoring wells. Lithium concentrations in MW-370 are five to nine times greater than the maximum lithium concentration (0.0182 mg/L) observed in BAP porewater.

If the BAP were the source of lithium in groundwater at MW-370, BAP porewater concentrations of lithium would be anticipated to be higher than concentrations at MW-370. Therefore, the BAP is not the source of the lithium observed at MW-370. Lithium concentrations at background monitoring well MW-304 are higher than BAP porewater, which also indicates lithium concentrations are from a source other than the CCR unit.

LOE #2: THE BAP POREWATER HAS A DIFFERENT IONIC COMPOSITION THAN GROUNDWATER.

Stiff diagrams graphically represent ionic composition of aqueous solutions. Figure 3 shows a series of Stiff diagrams that display the ionic compositions of groundwater from background monitoring wells (brown), downgradient monitoring wells (blue) and the BAP porewater (green). Polygons with similar shapes represent solutions with similar ionic compositions, whereas polygons with different shapes indicate solutions with dissimilar ionic compositions; the larger the area of the polygon, the greater the concentration of the various ions.

The ionic compositions of the groundwater and BAP porewater represented by Figure 3 are discussed in more detail below.

- The ionic composition of the groundwater in background and downgradient monitoring wells is similar, as represented by the similarity of the Stiff diagram sizes and shapes. The exception to this is MW-370.
  - The dominant cations in groundwater monitoring wells (background and downgradient) are sodium-potassium. However, the concentration of sodium-potassium in downgradient groundwater monitoring well MW-370 is higher compared to other groundwater monitoring wells.
  - With the exceptions of MW-370 and MW-382, the dominant anions in groundwater monitoring wells are carbonate-bicarbonate.
    - MW-370 is the only location where the dominant anion is chloride. This, coupled with the relatively high concentration of sodium-potassium cations in MW-370, results in a distinct polygon shape when compared to other groundwater sample locations.
    - The dominant anion at MW-382 is sulfate, however the concentration of carbonate-bicarbonate is consistent with the concentrations of carbonate-bicarbonate in other downgradient groundwater monitoring wells.
- The ionic composition of the BAP porewater is different than the ionic composition of the groundwater.
  - The dominant cation in the BAP porewater sample is calcium and the dominant anion is carbonate-bicarbonate. The resulting Stiff diagram is different in both shape and size from the groundwater diagrams.

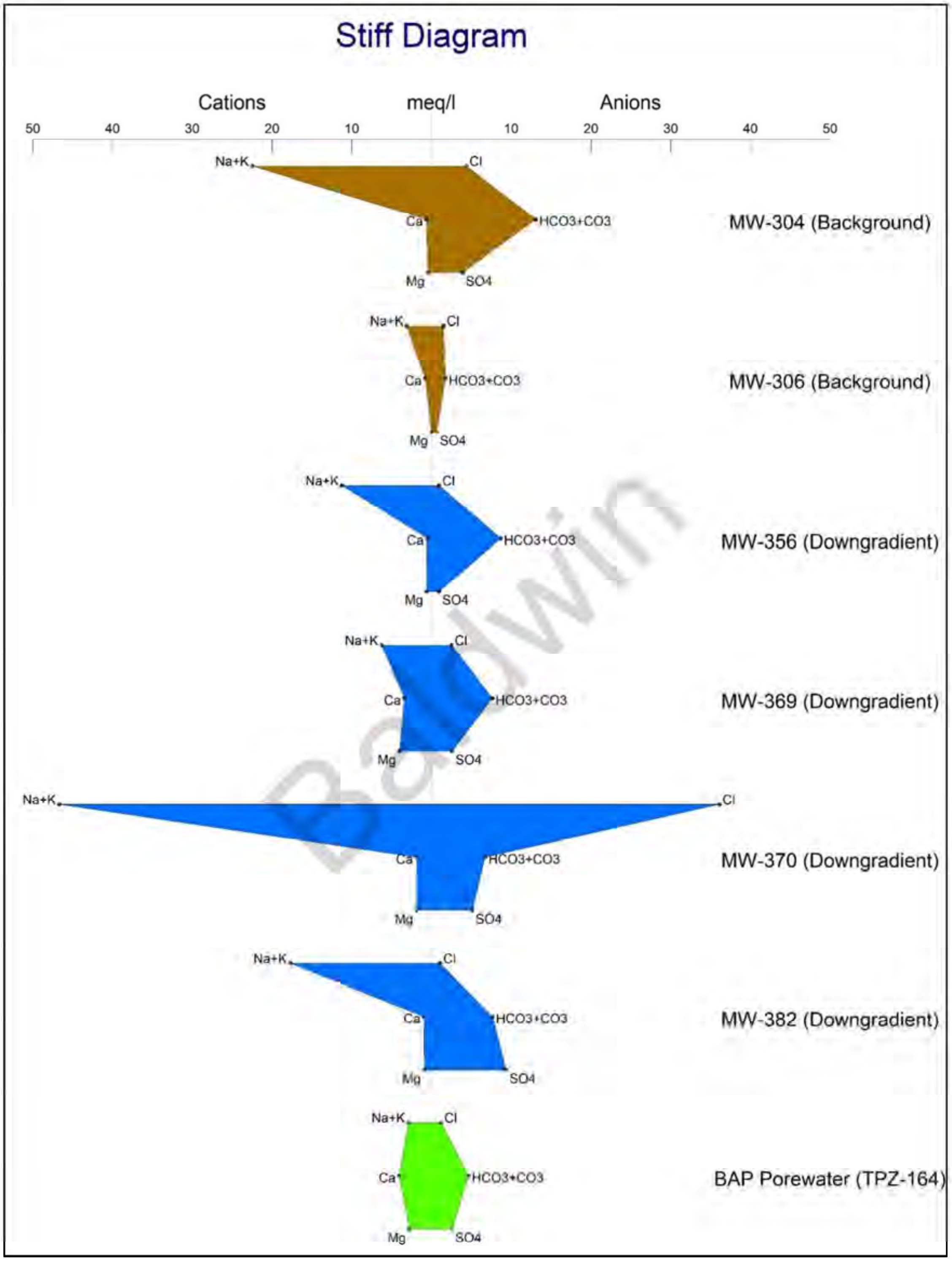


Figure 3. Stiff diagram showing ionic composition of samples of BAP background (brown) and downgradient (blue) groundwater and BAP porewater (green).

The Stiff diagrams and analysis of ionic composition in groundwater and the BAP porewater sample indicate that the ionic composition of groundwater at MW-370 is not influenced by the BAP.

Based on these two lines of evidence, it has been demonstrated that the lithium SSL at MW-370 is not due to the Baldwin BAP but is from a source other than the CCR unit being monitored.

This information serves as the written ASD prepared in accordance with 40 CFR § 257.95(g)(3)(ii) that the SSL observed during the A2 sampling event was not due to the BAP. Therefore, a corrective measures assessment is not required and the Baldwin BAP will remain in assessment monitoring.

Attachment A – Boring Log for Porewater Well TPZ-164

I, Eric J. Tlachac, a qualified professional engineer in good standing in the State of Illinois, certify that the information in this report is accurate as of the date of my signature below. The content of this report is not to be used for other than its intended purpose and meaning, or for extrapolations beyond the interpretations contained herein.

Eric J. Tlachac
Qualified Professional Engineer
062-063091
Illinois
OBG, part of Ramboll
Date: October 14, 2019

LICENSED PROFESSIONAL ENGINEER
ERIC J. TLACHAC
062-063091
STATE OF ILLINOIS

I, Jacob J. Walczak, a professional geologist in good standing in the State of Illinois, certify that the information in this report is accurate as of the date of my signature below. The content of this report is not to be used for other than its intended purpose and meaning, or for extrapolations beyond the interpretations contained herein.

Jacob J. Walczak
Professional Geologist
196-001473
Illinois
OBG, part of Ramboll
Date: October 14, 2019

LICENSED PROFESSIONAL GEOLOGIST
JACOB J. WALCZAK
196-001473
ILLINOIS

Figures

DRAWN BY/DATE: SDS
REVIEWED BY/DATE: JJW
APPROVED BY/DATE: JJW

MONITORING WELL AND BOTTOM ASH POND WATER SAMPLE LOCATION MAP
BALDWIN BOTTOM ASH POND

ALTERNATE SOURCE DEMONSTRATION
BALDWIN ENERGY COMPLEX
BALDWIN, ILLINOIS

PROJECT NO: 70093

FIGURE NO: 1

OBG Part of Ramboll

Electronic Filing: Received, Clerk's Office 08/27/2020

Attachment A

Boring Log for Porewater Well TPZ-164

KELRON ENVIRONMENTAL
Incorporated

LOG OF PROBEHOLE TPZ-164

(Page 1 of 1)

Phase II Hydrogeologic Investigation
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7		425						
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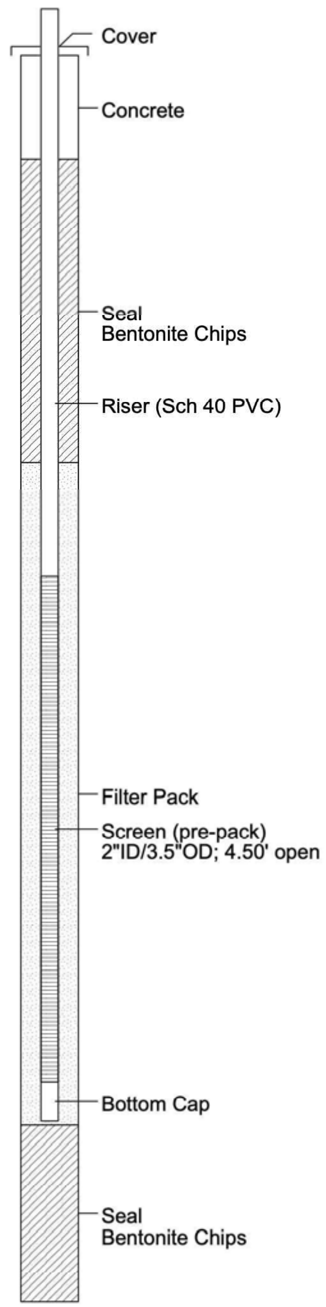
11		421	3		23/24		CL	
12	END BOREHOLE AT 10.3 FEET BLS END Split-Spoon Sampling at 12 feet BLS							

Well: TPZ-164
Elev.: 435.10



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11-08-2013 C:\Consulting A\Power Plants\Baldwin\Baldwin 2013 Hydrogeologic Study\Field Work Phase\Boring Logs\BEC164.BOR

ATTACHMENT 6

GEO-HYDRO, INC.
Consulting in Geology and Hydrogeology

16 Mesa Oak
Littleton, Colorado 80127
(303) 948-1417

July 26, 2019

Mr. Christopher Bowers
Southern Environmental Law Center
Ten 10th Street NW
Suite 1050
Atlanta, GA 30309

Subject: Review of Closure Permit Application and Other Pertinent Materials
Plant Scherer Ash Pond 1

Dear Chris,

I provide the following report at the request of Southern Environmental Law Center (SELC). I have reviewed a variety of documents pertinent to the current status and proposed closure of Ash Pond 1 (AP-1) at Georgia Power Company's (Georgia Power) Plant Scherer, located in Juliette, central Georgia. Throughout this report I cite to certain documents and evidence upon which I base my observations, opinions and conclusions. That does not mean, however, that the cited materials are the only sources of supporting evidence.

A central tenet of responsible waste management is that it be prevention-based. The United States Environmental Protection Agency (EPA) articulated this tenet in its 1993 guidance for owners and operators of solid waste disposal facilities stating: "Ground water is … used extensively for agricultural, industrial, and recreational purposes. Landfills can contribute to the contamination of this valuable resource if they are not designed to prevent waste releases into ground water … Cleaning up contaminated ground water is a long and costly process and in some cases may not be totally successful."[1]

Unlike other forms of solid waste such as municipal solid waste (MSW), inorganic coal combustion residuals and the metals they contain do not biodegrade. Coal ash that is left in unlined ash basins will be capable of leaching toxic metals into Georgia's groundwater at any time in the present, the near, or distant future for as long as soluble metals in the ash are allowed to come into contact with water. This is true for unlined facilities[2] whether or not a lateral barrier is placed along a portion of the ash impoundment, or whether a cap is placed on the top of the disposal area.

Therefore, an effective closure of coal ash storage sites requires that the coal ash waste be securely and permanently isolated from water: including precipitation, surface water, and groundwater. Failure to isolate coal ash waste from water will result in leaching of contaminants, i.e. formation of leachate. "Leachate" "includes liquid, including any suspended

[1] EPA, 1993, p.3
[2] Facilities constructed with no low permeability bottom liner that adequately restricts subsurface water flow

or dissolved constituents in the liquid, that has percolated through or drained from waste or other materials placed in a landfill, or that passes through the containment structure (e.g., bottom, dikes, berms) of a surface impoundment."[3] If released to groundwater or surface water, leachate from coal ash impoundments impairs and degrades water quality and the environment. Due to the lack of a bottom liner, unlined coal ash impoundments "allow the leachate to potentially migrate to nearby groundwater, drinking water wells, or surface waters."[4]

EPA concluded that leachate generated by coal-fired plants that use unlined surface impoundments equal about 70,300 toxic-weighted pound equivalents per year.[5] Thus, leachate from coal-fired power plants generates more equivalent toxic water pollution than the entire coal mining industry.[6] This finding illustrates the importance of implementing effective closures at coal ash impoundment sites. My review of Georgia Power's proposed Closure Plan for Plant Scherer AP-1 focused primarily on identifying factors that would inhibit the effectiveness of the proposed closure plan.

1. Background

Georgia Power is applying to the Georgia Environmental Protection Division (GAEPD) for a permit to close AP-1 under Georgia Rules for Solid Waste Management, Chapter 391-3-4-.10 (the state Coal Combustion Residuals (or "CCR") Rule). This letter documents the results of my review to date and identifies several significant findings that should be of interest and concern to GAEPD personnel. I reserve the right to amend, supplement or clarify my opinions based on the review of additional data and evidence, including any evidence uncovered by more complete and accurate disclosures by Georgia Power concerning Plant Scherer's AP-1.

2. Summary of Significant Findings

The following are the major findings that resulted from my review to date:

- The former channel of Berry Creek has been buried by at least 75-feet of saturated coal ash.
- Coal ash within the AP-1 impoundment is saturated by and is degrading the quality of groundwater within, beneath, and downgradient of AP-1. This impairment and degradation of groundwater quality will continue post-closure.
- The bottom of the ash is located less than 5-feet above the uppermost natural water table. In fact, the uppermost natural water table is above the bottom of the ash within AP-1, and will continue to be above that level post-closure.
- The southeast boundary of the proposed AP-1 closure area is located approximately 0.75 miles from a ground-water recharge area, a finding that indicates that a liner and leachate collection system should be required in order to permit a new waste disposal facility in

[3] EPA, 2015a, at 67,838 and 67,847
[4] EPA, 2015a, at 67,847
[5] EPA, 2015b, at 10-39 (Table 10-18)
[6] EPA, 2016, at 2-26 (listing equivalent pollution from other industries, including coal mining)

this location. Since Georgia state law flatly prohibits unlined municipal solid waste (MSW) landfills in this area, there is no valid reason for GAEPD to issue a permit for an unlined coal ash impoundment in this location.

- Georgia Power's Closure Plan proposes to close the unlined impoundment AP-1 in place on the floodplain of Berry Creek where the disposed waste will be subjected to re-wetting and erosion during high water events.
- Georgia Power appears to have no plans to evaluate the thickness or volume of saturated coal ash waste that would remain in place below the proposed cap contemplated by the closure plan.
- The bottom of the ash impoundment is and would remain unlined under the closure plan. Lack of a bottom liner, together with the depth of the groundwater table in relation to the depth of coal ash in AP-1 will result in coal ash remaining submerged in groundwater post-closure, degrading groundwater quality in perpetuity.
- There is no indication that Georgia Power intends to determine the extent of contamination that has already migrated from AP-1 and been detected in the current groundwater monitoring system.
- The existing groundwater monitoring system has detected elevated concentrations of ash-related contaminants, including: Boron, Calcium, Chloride, Cobalt, Fluoride, pH, Sulfate and TDS in wells located downgradient of the ash pond.
- Georgia Power's proposed closure plan does not appear to account for the fact that ash-related contaminants will continue to be released from the AP-1 basin post-closure. Nor would the plan evaluate the fate and extent of contaminants from the capped but unlined ash impoundment.
- The true magnitude and extent of current and foreseeable post-closure releases of ash-related contaminants from AP-1 have not been evaluated under Georgia Power's current monitoring and closure plan. As a result, there has been no comprehensive and substantive evaluation of the potential impacts to human health and the environment caused by the AP-1 impoundment, even though the evidence indicates that impacts are occurring, and will continue post-closure.
- The closure plan for AP-1 will not control, minimize, or eliminate post-closure infiltration of liquids into the waste, or releases of CCR, leachate, or contaminated run-off to the ground or surface waters. The closure plan will not accomplish these objectives because it would leave tens of feet of ash unlined, submerged in groundwater within a porous media.[7]
- For these reasons, the closure plan for AP-1 will not preclude the probability of future impoundment of water, sediment or slurry. Nor will the closure plan eliminate free liquids from AP-1 post-closure.
- Moreover, for the reasons stated herein, the closure plan will not minimize the need for further maintenance of AP-1.

[7] Ash and the underlying unconsolidated soils beneath, downgradient, and adjacent to AP-1

3. Qualifications

I express the opinions in this letter based on my formal education in geology and over thirty-nine years of experience on a wide range of environmental characterization and remediation sites. My education includes Bachelor of Science and Masters of Science degrees in geology from Northern Illinois University and the University of Illinois at Chicago, respectively. I am a registered Professional Geologist (PG) in Kansas, Nebraska, Indiana, Wisconsin, and North Carolina, a Certified Professional Geologist by the American Institute of Professional Geologists, and am a Past President of the Colorado Ground Water Association.

My entire professional career has been focused on regulatory, site characterization, and remediation issues related to waste handling and disposal practices and facilities, for regulatory agencies and in private practice. I have worked on contaminated sites in over 35 states and the Caribbean. My site characterization and remediation experience includes activities at sites located in a full range of geologic conditions, including soil and groundwater contamination in both consolidated and unconsolidated geologic media, and a wide range of contaminants. I have served in various technical and managerial roles in conducting all aspects of site characterization and remediation including definition of the nature and extent of contamination (including developing and implementing monitoring plans to accurately characterize groundwater contamination), directing human health and ecological risk assessments, conducting feasibility studies for selection of appropriate remedies to meet remediation goals, and implementing remedial strategies. Much of my consulting activity over the last 13 years has been related to groundwater contamination and permitting issues at coal ash storage and disposal sites in numerous states, including Alabama, Arizona, Colorado, North Carolina, Illinois, Indiana, Kansas, Maryland, Minnesota, Mississippi, Montana, New Mexico, Nevada, North Carolina, South Carolina, Pennsylvania, Virginia, Wisconsin. My current resume is enclosed.

4. Discussion

The following sections of this letter summarize my observations on reviewed documents that support these findings.

Impoundment Location and Construction

AP-1 is a 776 acre basin that Georgia Power constructed by placing an earthen embankment dam of approximately 8,000 feet across and around the Berry Creek drainage.[8] Materials used to build the dam and dikes surrounding the impoundment included residual soils from within and adjacent to AP-1. Earthen dams are prone to leaks in locations that may be referred to as “seeps.” A construction drawing[9] and a pre-development USGS topographic map[10] show that the lowest portion of the impoundment is at an elevation between 410 and 420 feet above mean sea level along Berry Creek.

[8] Georgia Power, 2016a, History of Construction
[9] Georgia Power, 2016a, History of Construction, Drawing E1H1029, pdf p. 12 of 26
[10] USGS, 1973, East Juliette, GA, 1:24,000 Topographic Map

Federal Coal Combustion Residuals (CCR) regulations require owners of coal ash impoundments to certify whether impoundments are lined or unlined, and whether the base of the impoundment is a minimum of 5-feet above the uppermost aquifer. Georgia Power has confirmed[11] that AP-1 is unlined and fails to provide 5-feet of vertical separation between the waste and the uppermost aquifer.

The southeast boundary of the proposed AP-1 closure area is located approximately 0.75 miles, and the entire proposed closure area is within the 2-mile restriction zone, of a significant ground-water recharge area.[12] Georgia's Comprehensive Solid Waste Management Act requires that any municipal solid waste (MSW) landfill located within 2-miles of a significant groundwater-recharge area have a liner and leachate collection system.[13] The logic behind that law flatly barring unlined MSW applies with at least equal force to the pollutants contained in coal ash as it does for household garbage – *it shouldn't be allowed to pollute Georgia's sensitive groundwaters in perpetuity*. Since Georgia state law flatly prohibits unlined MSW landfills in this area, there is no valid reason for GAEPD to issue a permit for an unlined coal ash impoundment in this location.

USGS topo maps[14] show that the impoundment was constructed by erecting a dam across Berry Creek at the approximate location where the creek changed from a perennial to an intermittent stream.[15] Berry Creek was identified as an intermittent stream above the location of the dam and as a perennial stream below the location of the dam. Surface water backed up behind the dam to a normal pool elevation of 495 feet above mean sea level.[16] Current aerial photographs show that a coal ash delta has formed and that exposed ash now covers the deepest portions of the impoundment, including the pre-existing channel of Berry Creek. Assuming that the exposed ash is no higher than the normal pool elevation,[17] the channel of Berry Creek within AP-1 is now buried under 75 to 85-feet of saturated coal ash. Georgia Power estimates that AP-1 currently contains approximately 15,700,000 cubic yards of CCR.[18]

The outer edge of the current coal-ash delta within impoundment AP-1 is located on the floodplain of Berry Creek and within the 1% annual chance flood area[19] indicated on the current Federal Emergency Management Agency (FEMA) Flood Hazard map[20] of the area. Locating a permanent waste disposal facility on the floodplain is problematic for at least two reasons. First,

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[11] Georgia Power, 2016b and 2016c

[12] Georgia Geologic Survey, 1989

[13] O.C.G.A. 12-8-25.2 (Sites within two miles of a significant ground-water recharge area)

[14] USGS, 1973 and 2011, East Juliette, GA, 1:24,000 Topographic Maps

[15] A perennial creek or stream is one that has a continuous flow of water in at least parts of the stream bed all year round during years of normal rainfall. Intermittent streams regularly cease flowing during certain times of the year.

[16] Georgia Power, 2016a, History of Construction, Drawing E1H1058, pdf p. 20 of 26

[17] This assumption may result in an underestimation of ash delta thickness since ash is typically deposited on the surface of the delta. This practice often results in build-up of ash above normal pool elevation.

[18] Georgia Power, 2016d, Initial Written Closure Plan, p.2

[19] The 1% annual chance flood, commonly referred to as the 100-year flood, is the area of the Berry Creek floodplain that has a 1% chance of flooding during any calendar year

[20] FEMA National Flood Hazard Layer Viewer

the coal ash waste in the unlined waste disposal cell would be re-wetted from below by rising groundwater associated with even relatively minor flood events. During high water events groundwater flows from the stream into surrounding sediments and the groundwater elevation rises in response. Where the bottom of the unlined waste disposal cell is located at or below the normal water table, such as at AP-1, rising groundwater elevations will re-wet wastes that are normally located above the water table and result in stimulated leachate production. Minimizing the potential for leachate generation and subsequent migration out of containment are key goals of permanent waste site closure that are not achieved under the Georgia Power Closure Plan

The second issue with the location of the waste disposal facilities adjacent to Berry Creek is the increased danger of damage and/or catastrophic release of coal ash during flood events. These dangers were illustrated in 2018 during the aftermath of Hurricane Florence when rising floodwaters at Duke Energy's L.V. Sutton power plant flowed through current and former ash impoundments, breached an ash landfill, and released an unknown quantity of ash. Under major flood events such as the 1%-annual-chance-flood, or greater, erosion of the new North Berm that is proposed to contain the disposed coal ash wastes in the deepest portions of the impoundment would be expected. Locating waste containment structures such as the proposed North Berm adjacent to the rerouted Berry Creek Channel and within the 100-year floodplain should be viewed, at best, as unacceptable waste management planning and practice with potentially catastrophic results for future Georgia residents.

<u>Proposed Closure Plan</u>

The Plant Scherer Closure Plan[21] establishes Georgia Power's intent to close AP-1 by the following major actions:

- Purportedly to remove free water from the impoundment;
- Route surface water flow around the outer edge of delta and outside of the proposed North Berm;
- Construct the new North Berm across the basin to contain the existing ash delta and ash that would be relocated from other areas of the impoundment;
- Excavate thin ash layers located outside of the North Berm and consolidate onto the delta. Ash would be consolidated over the deepest portion of the buried valley; and
- Place a composite final cover system over the ash purportedly to minimize vertical infiltration of precipitation into the ash.

No bottom liner or leachate collection system is proposed by the Closure Plan. No modeling to predict the amount of saturated ash that would remain after closure has been submitted. Nor has modeling been submitted to predict the extent of current or future groundwater contamination. These omissions are troubling. It is common practice to perform a comprehensive site characterization that can be used as a basis to develop a conceptual site model. This allows regulatory agencies to evaluate site characteristics and assess potential future impacts from a

[21] Georgia Power, 2018, Sections 7 and 8

given closure plan. Here, the lack of such data will impair GAEPD's ability to evaluate the extent of groundwater and environmental degradation that can and will likely result from the Closure Plan's implementation. Such considerations, particularly as relate to potential adverse impacts to human health, should be considered of paramount importance given the many residences located in close proximity to the site.

Impoundment Site Geology

The groundwater monitoring plan[22] describes the geology of the AP-1 site as underlain by regolith consisting of residual soils and saprolite overlying fractured, crystalline bedrock. Local bedrock consists of gneiss with layers and lenses of schist and amphibolite. Residual soils, primarily sandy silt, silty sand, sandy clay and silty clay, occur as variably-thick blanket overlying bedrock across most of the site. The thickness of residual soil ranges from a minimum of approximately 17 feet to as much as 168 feet. The thickness of saprolitic soil and/or saprolitic rock is variable.

Impoundment Site Hydrogeology

The groundwater monitoring plan[23] describes groundwater as occurring within both the regolith and fractured bedrock beneath the site. The water-table occurs within the overburden and is generally unconfined. Groundwater flows through the porous regolith, is recharged by precipitation and typically discharges into streams and rivers. The water table surface is generally a subdued reflection of surface topography. Recharge to the bedrock aquifers comes from groundwater that infiltrates into the rock through zones of enhanced permeability (*i.e.* fractures).

There is no subsurface confining layer below or adjacent to AP-1 that would otherwise act to restrict the post-closure migration of groundwater into AP-1, infiltration of liquids into AP-1, lateral migration of contaminants from AP-1, future impoundment of water within the ash basin, or the continuing presence of liquids within AP-1 post-closure.

Prior to impoundment construction, groundwater flowed from higher topographic areas located north, west, and south of the creek toward discharge areas along Berry Creek. Groundwater that discharged from the regolith into Berry Creek flowed downstream and was rapidly removed from the local hydrogeologic system.

The filling of the Berry Creek valley with water and coal ash radically altered groundwater flow directions, pathways, ingress, and egress from the site. Under current conditions groundwater continues to flow toward the impoundment from slightly higher elevations to the west, and out of the pond to recharge groundwater on the north, south, and east sides of the impoundment. Flow of water out of the impoundment and into groundwater under current conditions is reflected in groundwater quality monitoring results described below.

[22] AECOM, 2018, Closure Permit Application Part A- Section 6
[23] AECOM, 2018, Closure Permit Application Part A- Section 6

Removal of the free standing water as contemplated by the proposed Closure Plan will significantly reduce the hydraulic head that currently drives Plant Scherer's AP-1 coal ash contaminants out of the Berry Creek valley. This reduction of the head would be a positive development if the accumulated ash materials were located above the water table. But the closure plan proposes to leave the accumulated ash delta in place, without a bottom liner -over the deepest portions of the impoundment. With removal of the free standing surface water, groundwater will attempt to return to natural flow conditions. Unfortunately, however, the groundwater will be unable to return to pre-development conditions because discharge areas along the previous surface water channel will remain buried under the coal ash waste. Groundwater that previously discharged from the regolith to surface water or into alluvial sediments along the creek will now discharge *into* the accumulated coal ash in perpetuity. Rather than being rapidly removed from the hydrogeologic flow system as stream flow under conditions as they existed prior to the area being used as a waste disposal area, the water will instead discharge into another porous media, coal ash within AP-1. This change will cause saturated conditions to exist at higher elevations than those present prior to burying the area in coal ash for as long as the ash remains in that location. This will in turn promote generation of leachate that will eventually discharge into the creek, carrying mobilized coal ash pollutants with it.

Other generation facilities[24] that have proposed similar Cap–In-Place closure scenarios for ash impoundments have typically conducted multiple phases of groundwater flow and transport monitoring in at least an *attempt* to predict how much of the buried waste will remain saturated, and to further predict how far downstream water quality impacts may persist after waste consolidation and capping. Here, no such predictive modeling effort has been conducted in support of the AP-1 Closure Permit Application. This omission results in the lack of important data. Nevertheless, currently available information supports the findings set forth above concerning present and future groundwater degradation, future impoundment and release of leachate, and contamination of Berry Creek by post-closure discharge of leachate from AP-1. Additional site investigation would serve to more accurately assess those impacts in comparison with the relatively limited dataset provided by Georgia Power.

Groundwater Quality Monitoring

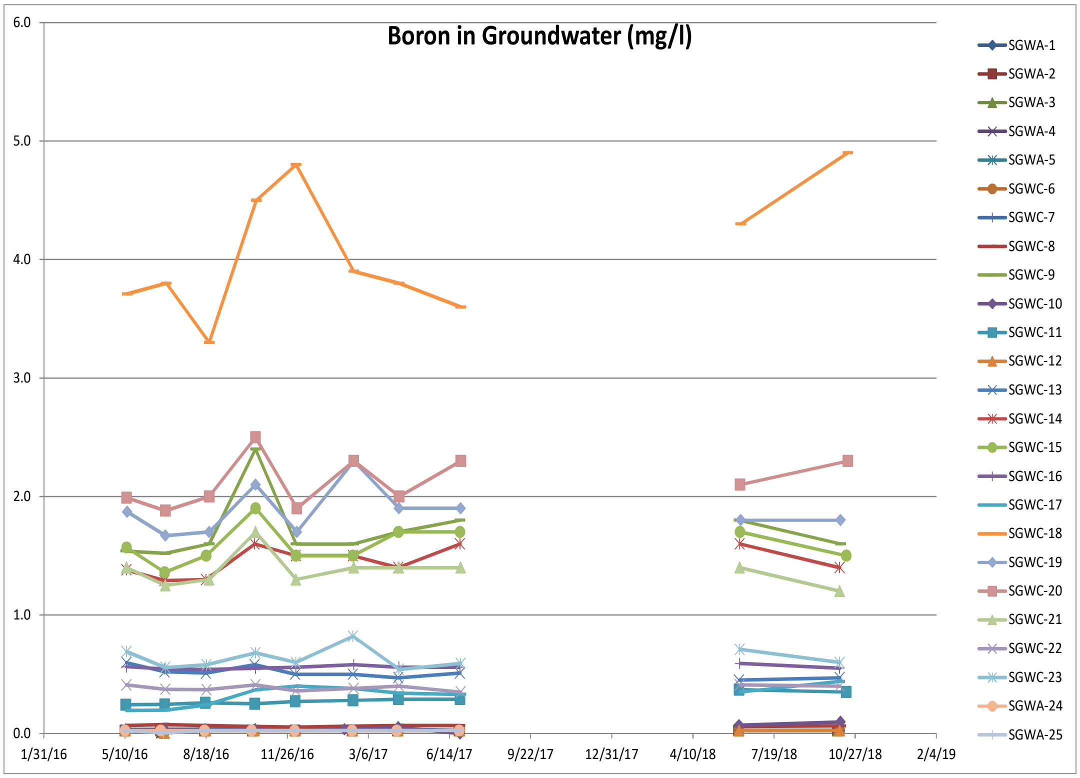
Groundwater quality monitoring required by the Federal CCR rule has shown that groundwater around the AP-1 impoundment is impacted with coal ash-related contaminants. Ash-related contaminants detected above background include the common ash–related contaminants Boron, Calcium, Chloride, Fluoride, pH, Sulfate and TDS.[25] Impacted wells include: SGWC-7, SGWC-8, SGWC-9, SGWC-10, SGWC-11, SGWC-12, SGWC-13, SGWC-14, SGWC-15, SGWC-16,

[24] Examples include the Roxboro, Mayo, and Belews Creek Generating Stations in North Carolina. On April 1, 2019, the North Carolina Department of Environmental Quality determined based on the science that excavation of these and three other unlined coal ash impoundments is the only closure option that met state standards "to best protect public health and the environment." Department of Environmental Quality, North Carolina Closure Determination April 1, 2019, see https://deq.nc.gov/news/key-issues/deq-orders-all-coal-ash-excavated

[25] Boron, Calcium, Chloride, Fluoride, pH, Sulfate and TDS are Federal CCR rule Appendix III coal ash parameters

SGWC-17, SGWC-18, SGWC-19, SGWC-20, SGWC-21, SGWC-22, and SGWC-23. The time versus concentration plot of Boron concentrations in groundwater (below) illustrates the variation in groundwater quality impacts between wells.

Monitoring well SGWC-18 is the most highly impacted of the monitoring wells, with concentrations of cobalt, boron, sulfate and TDS notably higher than the other monitoring wells. A statistically significant increase in Cobalt[26] was documented in the 2018 annual monitoring report.[27] Well SGWC-18 is located off the southeast corner of the impoundment at end of the dam.



Using a flawed sampling methodology, Georgia Power's consultants attempt to attribute the contaminants to a source other than the coal ash within AP-1, which is implausible. A more comprehensive sampling protocol is necessary to render an accurate picture of the sources of contamination detected at and in the vicinity of Plant Scherer AP-1. For example, rather than investigate the extent of the statistically significant increase in Cobalt and other ash-related parameters, Georgia Power submitted an Alternate Source Demonstration[28] that purports to attribute this contamination to natural site conditions. But there is insufficient information to determine whether the Alternate Source Demonstration for Cobalt is valid. Specific information missing from the Alternative Source Demonstration is identification of the depth of interstitial water samples collected from within the ash delta. For instance, it is commonly understood that samples collected from upper layers of an ash basin often show relatively low concentrations of

[26] Cobalt is a Federal CCR rule Appendix IV coal ash parameter
[27] Golder Associates, 2019
[28] Golder, 2019, Appendix C

ash-related contaminants due to dilution from precipitation and the short contact time between the ash and water at that depth, in comparison with samples collected from within lower portions of the water column. Interstitial water samples collected within lower portions of the ash column provide a better indication of the chemistry of leachate that is leaving the impoundment and impacting underlying groundwater quality.

A more accurate assessment of Cobalt concentrations would collect samples screened at multiple depths within the ash, where higher concentrations can be expected to occur. No data concerning sample collection depth, much less collection at multiple depths in the ash are provided in the Alternative Source Demonstration. These omissions render the conclusions of the Alternate Source Demonstration materially unreliable. GAEPD should require collection of samples from multiple depths within the ash in at least three locations within AP-1, to ensure complete accurate data for comparison against upgradient background values for Cobalt and other coal ash constituents detected at the site, including Calcium, Chloride, Fluoride, pH, Sulfate and TDS.

Setting aside the flawed sample and reporting methodologies for Cobalt, there is no question, however, that these multiple other common ash-related constituents are found in high concentrations in the same well evaluated in the Alternate Source Demonstration. In fact, monitoring well SGWC-18 is the downgradient monitoring well showing higher concentrations than any other well in the monitoring system. Georgia Power has made no apparent effort to determine the magnitude and extent of ash-related groundwater contamination caused by AP-1. The Company appears more interested in attributing away the detected pollution to sources other than its massive coal ash waste disposal unit than in providing an accurate picture of site contamination.

The above findings are based on my review of available sources, including materials submitted by Georgia Power to GAEPD, the content of Georgia Power's CCR Rule Compliance Data and Information website, and my education, qualifications, experience, and expertise. I would be happy to discuss the planned closure of Plant Scherer AP-1 with you and/or GAEPD at any time.

Please let me know if you have questions or comments.

Sincerely,

Mark A. Hutson, P.G.
303-948-1417
mhutson@geo-hydro.com

Enclosure

Documents Reviewed

Data and information sources reviewed included the following documents:

AECOM, 2018, CCR Surface Impoundment, Ash Pond 1, Closure Permit Application, Monroe County, Georgia, November 2018.

EPA, 1993, *Criteria for Solid Waste Disposal Facilities, A Guide for Owners/Operators*, EPA/530-SW-91-089, March 1993, *available at* https://www.epa.gov/sites/production/files/2016-03/documents/landbig.pdf

EPA, 2015a, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. (November 3, 2015) (40 C.F.R. Part 423), available at https://www.govinfo.gov/content/pkg/FR-2015-11-03/pdf/2015-25663.pdf

EPA, 2015b, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-15-007 (September 2015), available at https://www.epa.gov/sites/production/files/2015-10/documents/steam-electric-tdd_10-21-15.pdf

EPA, 2016, Annual Effluent Guidelines Review Report, EPA-821-R-16-002 (June 2016), available at https://www.epa.gov/sites/production/files/2016-06/documents/2015-annual-eg-review-report_june-2016.pdf

FEMA National Flood Hazard Layer (NFHL) Viewer, 1% Annual Chance of Flood Hazard, at https://fema.maps.arcgis.com/apps/webappviewer/index.html?id=29f87515702d4845a906419b287e2049

Georgia Geologic Survey, 1989, Most Significant Ground-Water Recharge Areas of Georgia, Hydrologic Atlas 18, reprinted 1992, available at https://epd.georgia.gov/sites/epd.georgia.gov/files/related_files/site_page/HA-18.pdf

Georgia Power, 2016a, History of Construction, 40 C.F.R. Part 257.73(c)(1)(i)-(xii), Plant Scherer Ash Pond (AP-1), at https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-scherer/20161017-constrhist-sch-ap1-final.pdf

Georgia Power, 2016b, Location Restriction Demonstration, Uppermost Aquifer (40 C.F.R. 257.60), plant Scherer Ash Pond 1 (AP-1), at https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-scherer/20181017_aquifer_sch_ap1_final.pdf

Georgia Power, 2016c, Liner Design Criteria, 40 C.F.R. Part 257.71, Plant Scherer Ash pond (AP-1), at https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-scherer/20161017-liner-sch-ashpond-final.pdf

Georgia Power, 2016d, Initial Written Closure Plan, 40 C.F.R. Part 257.102, Plant Scherer Ash pond (AP-1),at https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-scherer/20161017-clospln-sch-ap-final.pdf

Golder Associates, 2018, 2017 Annual Groundwater Monitoring and Corrective Action Report, Georgia Power Company – Plant Scherer, Ash pond (AP-1), January 30, 2018, at https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-scherer/20180131-annualgwreport-sch-ap-final-rev1.pdf

Golder Associates, 2019, 2018 Annual Groundwater Monitoring and Corrective Action Report, Georgia Power Company – Plant Scherer, Ash pond (AP-1), January 31, 2019, at https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/plant-scherer/20190131_AnnualGWReport_SCH_AP_FINAL.pdf

United States Geological Survey, 1973, East Juliette, GA, 1:24,000 Topographic Map.

United States Geological Survey, 2011, East Juliette, GA, 1:24,000 Topographic Map.

Electronic Filing: Received, Clerk's Office 08/27/2020

Enclosure

Resume of Mark Hutson, P.G.

The following are attachments to the testimony of Mark Hutson.

ATTACHMENT 7

ClosureTurf®
A PREDICTABLE BENCHMARK OF PERFORMANCE

MADE WITH agru STRUCTURED MEMBRANES

ClosureTurf®
ADVANCED FINAL COVER SYSTEM

Soil Slopes Don't Work, Although They Keep You Working

Soil erosion continually plagues the ongoing management of landfills, industrial waste sites, CCR storage areas, and other environmental containment applications requiring constant rebuilding of slopes weakened by rain and wind. In addition to ongoing maintenance headaches, traditional systems utilizing soil as their main component are costly to maintain, slow to install and introduce unwanted slope stabilities. ClosureTurf® is the only solution that provides a predictable benchmark of performance.

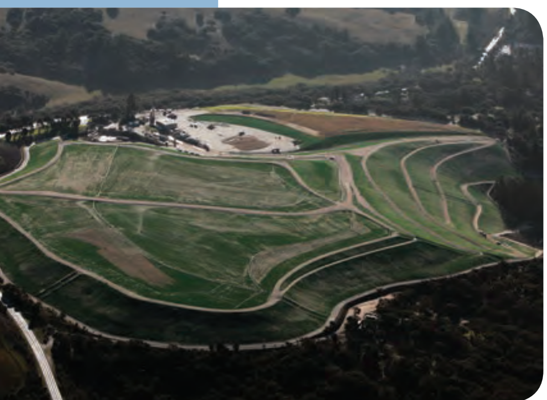
A prescriptive cover is effectively an engineered structure reliant upon vegetation and weather to perform as designed. With this in mind, ClosureTurf was designed to provide an engineered solution to Subtitle D requirements that would perform under all conditions. It is quickly becoming the closure system of choice across the country for engineers, owners , government agencies and many others who are seeking the best solution for their containment challenges. The ClosureTurf system offers exceptional stability, long-term protection and natural aesthetics all for a comparable price to traditional designs.

ClosureTurf® Makes Erosion Control Easy—It's Virtually Install and That's All.

ClosureTurf is a patented, three-component system comprised of a structured geomembrane, an engineered synthetic turf and a specified infill. The ClosureTurf system provides predictable performance over a vegetated Subtitle D landfill cover by:

- Reducing construction and long-term maintenance costs
- Exceeding technical performance factors
- Withstanding extreme weather conditions
- Lasting well beyond the post-closure care period
- Easily incorporating into existing gas collection systems
- Improving storm water quality
- Allowing for Incremental closures for quicker gas control, odor control and leachate reduction

With a footprint of over 1,200 acres, ClosureTurf has proven to be superior in performance when compared to other cover solutions. Because of its consistent ability to meet and/or exceed compliance and performance standards, ClosureTurf is the preferred method in landfill final cover designs for many.


Crazy Horse Landfill, CA

Construction Benefits

- Installs at least 50% faster than traditional soil caps
- Eliminates on average 550 truck trips of soil per acre from local roadways
- Allows for incremental closures
- Eliminates 2 feet of soil; no borrow soil
- Easily adapted during or after construction for solar field development


Baldwin County Landfill, GA

Technical Performance

- Prevents common erosion, storm water and siltation problems—even during severe weather events
- Utilizes the highest interface friction geomembrane available in the market for greater stability on steeper grades and eliminates the need to rebuild slopes
- With a design life of 100+ years, the lifespan of the ClosureTurf system extends well beyond the post-closure maintenance period
- Protects against driving forces, severe weather conditions heat and wind uplift


Portola Landfill, CA

Cost Savings

- Reduces maintenance and post closure care by around 90% compared to a soil cap
- Reduces sediment loading clean out to surrounding channels and sedimentation/detention basins

Environmental Impacts

- Provides clean runoff with very low turbidity
- No soil, chemicals or fertilizers to contaminate the water
- Obtain control over gas collection sooner than later ("close as you go")
- Reduces overall surface emissions
- Lowers the production of leachate with incremental closures
- Durable system construction designed to safely convey internal gas pressures, reduce unwanted releases and avoid slope stability issues
- Requires no irrigation, fertilizing, seeding or mowing
- Reduces environmental carbon footprint by up to 80% during construction

11 NTU 371 NTU

Runoff from a typical 1" rainfall (same site); ClosureTurf (left); traditional soil cover (right)

Port Angeles Landfill, WA

TAKE A CLOSER LOOK AT CLOSURETURF

ClosureTurf is a patented, three component system comprised of a structured geomembrane, an engineered synthetic turf and a specified infill. The foundation of the system is an impermeable, highly transmissive structured geomembrane. It provides for the highest interface friction values available in the market. The engineered synthetic turf component gives the system its natural look and feel of grass while protecting the geomembrane from extreme weather conditions for the long term. The specified infill component is placed between the blades of the engineered turf and allows the system to be trafficked while also providing additional protection from weathering. While ClosureTurf incorporates easily into existing gas collection systems, the patented gas relief valve protects against build-up/ballooning if the gas collection system malfunctions. ClosureTurf is fast and easy to install for an aesthetically pleasing, cost-effective landfill closure solution.

ENGINEERED SYNTHETIC TURF

- Dimensional stability
- High interface friction
- Aesthetically pleasing
- Virtually maintenance free
- Superior resistance to:
  - Extreme weather
  - Long-term UV exposure
  - Heat

STRUCTURED GEOMEMBRANE

- Studs on top provide quick drainage of high intensity rainfall events
- Spikes on bottom provide high friction to subgrade
- Exceeds most regulatory thickness requirements by 20 %

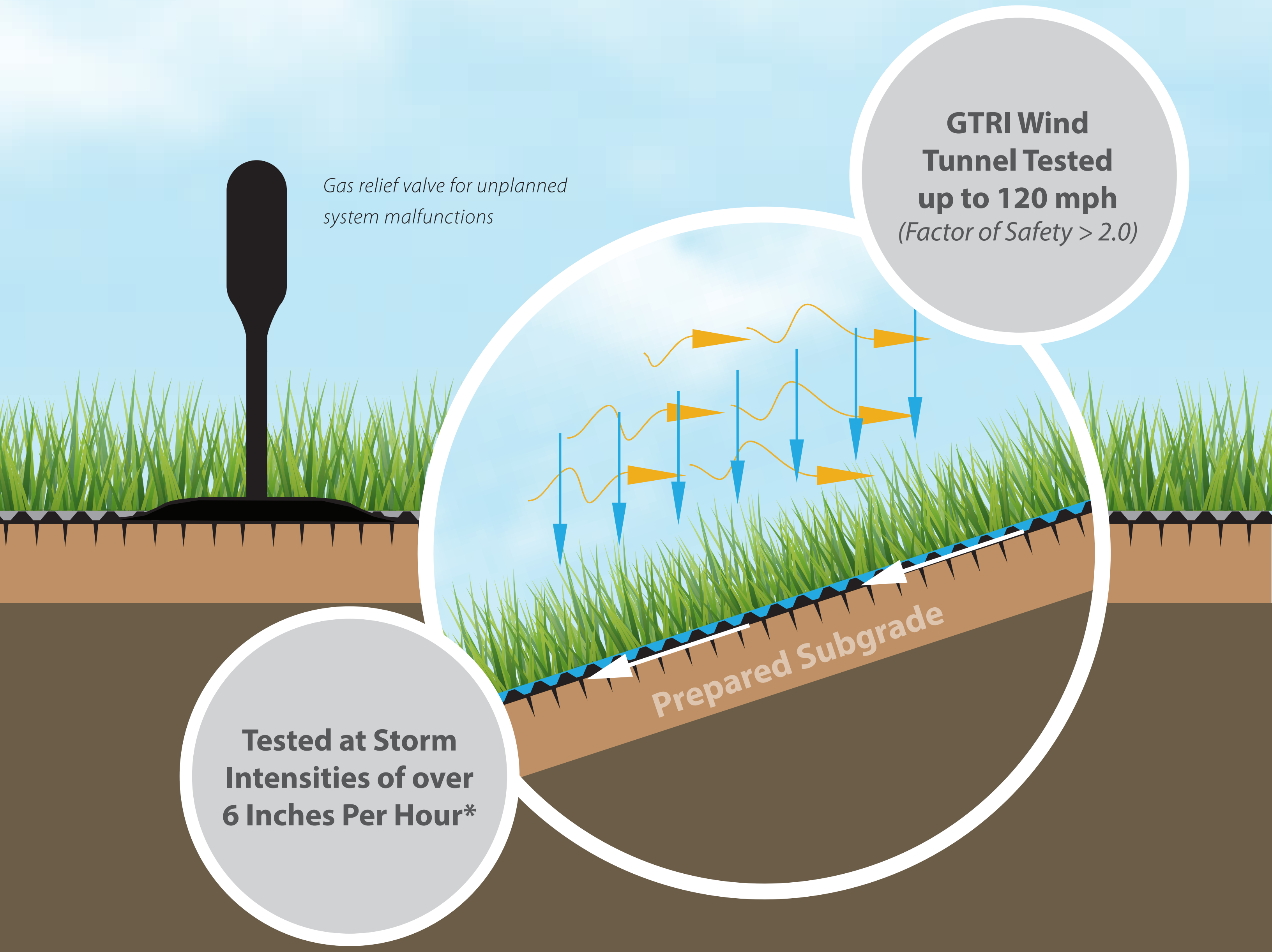
SPECIFIED INFILL

- Supports heavy traffic loads
- Provides additional UV protection
- Lab tested in high rainfall events
- Creates a non-exposed system
- Superior weathering protection
- Reduces heat absorption

ClosureTurf®

WASTE

ClosureTurf is specifically designed for long-term slope stability in the wake of severe weather events such as intense rainfall, hurricane force winds and earthquakes.



** Most significant rainfall event to date is 22 inches over 24 hours with no damage to the ClosureTurf system.*

WASTE

Electronic Filing: Received, Clerk's Office 08/27/2020

Solatics® is a patented solar system that uses ClosureTurf® as its foundation to turn an environmental liability into an environmental asset. Installing solar generation on capped landfills has proven an effective way to deploy large systems on typically unused space. By combining the proven technology of ClosureTurf with the advanced science of Solatics, the system yields the highest producing, easiest to maintain solar solution available on the market. ClosureTurf's unique cover system enables solar panels to operate in a clean environment free of dust, grass clippings and potential damage from lawn mowing equipment. With a no penetration, friction-based attachment method, Solatics is able to operate and function with optimal performance.

Why Siting Solar on Landfills is Superior to Other Sites, including Greenfields:

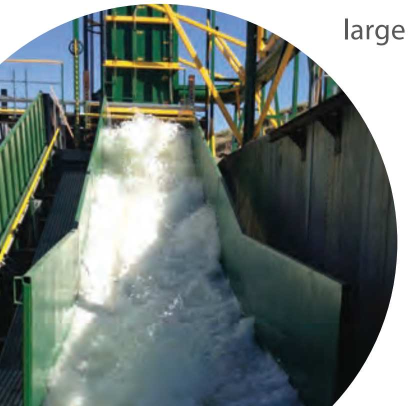
- Productive use – financially and environmentally – of land resource with minimal typical reuse
- Receives superior financial incentives in some jurisdictions
- Prevents clear-cutting and grading of forests and greenfields
- Makes use of existing access roads, storm water management and security perimeters

Solatics is the only solar technology of its kind:

- Uses the latest dual glass panel proprietary technology
- Utilizes a low profile direct attachment system to protect against wind uplift and shear
- Does not use bulky racking material
- Does not penetrate the closure system
- Maximizes the landfill footprint with both top deck and slope positioning
- Simplifies wiring and increases the power per unit area by more than 35%

HydroTurf® Storm Water Revetment Technology

HydroTurf is an innovative, environmentally-friendly alternative revetment to rock and concrete hard armor linings for landfill storm water management system applications, including downchutes, perimeter channels, bench drains, outfall structures, slopes and basins. It is a patented, three-component system made up of a structured geomembrane, an engineered synthetic turf and a specialized cementitious infill called HydroBinder®. Created specifically for hydraulic applications on landfills, HydroTurf will flex and move with typical differential settlements without compromising performance. It provides superior hydraulic properties capable of handling large flows resulting in very high velocities.



HydroTurf has been comprehensively tested at Colorado State University (CSU). CSU's laboratory has the largest flumes for hydraulic testing in the world. HydroTurf did not reach failure at a maximum steady state overtop velocity of 40 feet/second and for 13 hours in the wave overtop simulator being subjected to a five-hundred-year hurricane event for the New Orleans region.

Benefits Over Traditional Landfill Storm Water Management Systems:

- Excellent hydraulic performance
- Less costly
- 50+ years of functional longevity
- Flexible solution for all settlement conditions
- Impermeable for superior erosion control
- Lightweight for rapid, low-impact and scalable construction
- Easy to install in difficult areas
- Minimal long-term maintenance
- Natural aesthetics to match surrounding environment

VersaCap® Intermediate Cover

VersaCap is a wind and erosion resistant, intermediate engineered turf cover that reduces operational headaches and allows for increased gas collection efficiency before final closure. VersaCap prevents erosion, infiltration, runoff and gas emissions during the operational phases of the landfill, and is designed to have a 15+ year life span. It is fast and easy to install, and does not include tires or sandbags to keep it in place.

ClosureTurf® Surficial Gas Landfill Management System

The ClosureTurf Surficial Gas Collection System is a cutting edge technology that outperforms conventional gas collection systems on every metric. It also integrates well with the latest vertical columns for collection and drainage. In many cases, you can reduce the reliance on deep gas wells. The system relies upon positive internal landfill pressures to push the gas to the surface below the geomembrane where collection strips guide the gas to collection points. Benefits include reduced condensate management and treatment, higher collection efficiencies, a potential elimination of landfill oxidation and higher compliance standards (surface scans). It also allows for quicker gas control.

AFFILIATIONS:
Geosynthetic Institute (Partner)
Georgia Tech Research Institute (Partner)
Industrial Fabrics Association International (Member)
Colorado State University - Engineering Research Center (Partner)
Florida Atlantic University (Partner)
Iowa State University (Partner)

CLOSURETURF IS TESTED IN ACCORDANCE WITH:
GTRI-SSWT - Aerodynamic Shear & Uplift
CSU USACE - Hydraulic Wave Overtopping
ASTM D5261 - Mass per Unit Area
ASTM D4632 - Grab Tensile Properties
ASTM D4595 - Wide - Tensile
ASTM D2256 - Tensile and Elongation
ASTM D4716 - Hydraulic Trasmissivity
ASTM D5321 - Interface Shear
ASTM D6460 - Large Scale Channel Hydraulics
ASTM D6241 - CBR Puncture
ASTM D6459 - InFill Stability
ASTM D4884 - Seam Strength
G147(02) & G145/G7 - UV Resistance & Stability
UL94 Modifiers - Flammability
ASTM D7277 - Steady State Hydraulic Overtopping
ASTM E 108 - Burning Brand

WatershedGeo®
Unearthing Solutions

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ATTACHMENT 8

Frequently Asked Questions

> Will the sand stay in place?

Yes. The sand infill, along with the system's transmissivity, is specifically designed to handle more than six inches of rainfall per hour with minimal erosion. Plus, the engineered turf works as a grid that "locks" the sand in place to help resist erosion should rainfall exceed the drainage layer's flow capacity.

> How stable is the system and what is the interface friction?

The ClosureTurf® system is exceptionally stable, with an interface friction of 43 degrees between the engineered turf and Super Gripnet. In fact, this equates to a 3.0 safety factor for typical landfill slopes.

> How is the system anchored?

ClosureTurf typically is only terminated at the toe or on the outside perimeter swale. Anchoring to resist pullout forces is not needed since ClosureTurf incorporates a high-friction, continuous ballast that resists sliding.

> What about wind resistance?

ClosureTurf's unique ballast and aerodynamic properties provide cover uplift resistance for high category hurricane force winds.

> Can equipment be driven on the Closure*Turf* system?

Yes. Typical maintenance vehicles with ground pressure of up to 100psi can operate on the system.

> How long will the turf last? What about fading?

An independent UV weathering study performed on our engineered synthetic turf utilized accelerated extreme exposure conditions to indicate longevity over 100 years to half life as proven by multiple independent evaluations. The engineered synthetic turf also provides a protective covering for the membrane against heat and UV degradation adding many years of functional life to the membrane.

> What colors are available?

ClosureTurf can be produced in green, tan or a green-tan blend to optimally blend in with the surrounding environment.

> Is wind erosion a factor?

Wind erosion is not a factor. In fact, ClosureTurf's grass strands and stable sand infill minimize the effects of wind erosion.

> How does Closure*Turf* respond to gas build up as a result of collection system shutdowns?

The ClosureTurf system includes pressure relief valves that can prevent uplift in the event of a flare shutdown. These valves can also integrate into existing GCCS systems.

ClosureTurf®

Frequently Asked Questions

› Is Closure*Turf*® currently being approved as a final cover?

Yes, the system has received approval by several states and by the EPA as a final cover system. The system far exceeds the performance established by states' prescriptive design and EPA "Subtitle D" criteria. Due to ClosureTurf's ability to help lower a state's and local government's potential liability for closure care and environmental superiority over a Subtitle D standard cover, we anticipate final cover approval in all states and territories.

› What happens when the system needs replacing in the future?

It's true that the engineered turf component may need to be replaced at some point in the distant future (i.e. 100 years+) based on level of care, however, this is a very minimal financial obligation when compared to the savings of not having to perform on-going erosion repair, mowing and reseeding. Note that due to the protection of the membrane as provided by the engineered turf, it is expected to last several hundred years.

› How does Closure*Turf* address environmentalists concerned about artificial grass?

ClosureTurf is more environmentally friendly than the current EPA Subtitle D cap requirements because it:

- Offers over a 75% reduction in the carbon footprint compared to traditional covers
- Creates less siltation and associated ecological impacts to waterways
- Eliminates land destruction for borrow
- Is 100% recyclable
- Returns more water to the environment
- Reduces truck trips/haul trips by 500 to 600 per acre
- Greatly reduces GHG releases through more frequent, incremental closures

› What is the oldest real-world example of Closure*Turf*?

The first installation of ClosureTurf was in 2009 at the Lasalle-Grant landfill in Jena, Louisiana. This was a 9-acre municipal solid waste landfill that has continued to perform successfully with no failures to date. In fact, over 25 million square feet of ClosureTurf has been installed successfully with no reported problems or failures in 18 states since inception.

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Unearthing Solutions

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v.4.16

ATTACHMENT 9

LOCAL

Arsenic levels decline in pollution tests at LR coal plant

By SAMMY FRETWELL

sfretwell@thestate.com

FEBRUARY 01, 2016 09:14 PM

SCE&G's coal fired power plant has pro[…]he Wateree River, but the plant has left a legacy of coal ash to clean up in easte[…]VELL/THE STATE

Levels of a toxic pollutant are dropping in groundwater near the Wateree River as SCE&G continues to clean up coal ash, the messy by-product of making electricity in eastern Richland County.

Recent groundwater testing shows sharp declines in arsenic levels at several spots on the company's Wateree power plant site, according to a report SCE&G prepared for the S.C. Department of Health and Environmental Control last month

TOP ARTICLES

“We are on the way to getting out of the woods,’’ said Frank Holleman, an attorney with the Southern Environmental Law Center, which sued on behalf of the Catawba Riverkeeper Foundation to force the cleanup. “This is significant because these ash lagoons were right on the Wateree River upstream from Congaree National Park.’’

Since settling the lawsuit with the center in 2012, SCE&G has removed 876,000 tons of coal ash from waste lagoons on the property. All told, the company’s plan is to dig out more than 2 million tons of ash. It has developed a lined landfill in Lower Richland for waste ash generated at the coal-fired power plant.

Coal ash includes toxins, such as arsenic and metals, that can leak through the bottom of unlined ash lagoons and into groundwater. Arsenic is a poisonous material that can sicken people and wildlife exposed in sufficient amounts.

SCE&G spokesman Eric Boomhower said the ash removal efforts “have had a positive impact on groundwater.’’

According to test results analyzed by Holleman’s organization, arsenic levels have dropped more than 90 percent at two test wells that once registered some of the highest readings beneath the ash ponds.

SCE&G’s 46-year-old Wateree coal plant has been the subject of multiple lawsuits over coal ash dumped at the site and groundwater contamination beneath ash waste ponds. Details of the groundwater pollution came out as part of a 2009 lawsuit, brought by a Lower Richland farmer who had challenged the company’s future disposal plans. Evidence produced for the trial showed arsenic had polluted groundwater at levels above the safe drinking water standard, but the contaminant also was draining through an earthen ash pond wall toward the Wateree River.

In 2012, the Southern Environmental Law Center sued to force the cleanup of the ash ponds. The law center has filed legal action across the Carolinas, seeking to force power companies to dig up coal ash from ponds and truck it to lined landfills. SCE&G, Santee Cooper and Duke Energy have agreed to do so in South Carolina, but the law center remains at odds with Duke over ash cleanup plans at some power plants in North Carolina.

Robert Yanity, a spokesman for the S.C. Department of Health and Environmental Control, had no immediate comment Monday on the groundwater test results.

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Santee Cooper’s coal ash removal reducing arsenic levels

DAVID WREN

JUN 5, 2016

Boeing South Carolina workers put together the 787 Dreamliner midbody sections at the company’s North Charleston campus.

Electronic Filing: Received, Clerk's Office 08/27/2020

Arsenic levels at a closed Santee Cooper power plant in Conway have plummeted as the Moncks Corner-based electric utility removes coal ash from unlined pits at the former coal-fired Grainger facility.

Santee Cooper has removed more than 500,000 tons of coal ash from the site — nearly half of the ash that once existed in the pits along the Waccamaw River. Arsenic levels in groundwater at the site have dropped by between 60 percent and 90 percent, according to the Southern Environmental Law Center, which is monitoring the cleanup.

“These results show that removing coal ash from unlined riverfront pits dramatically reduces pollution, as well as the risk of catastrophic failure,” Frank Holleman, senior attorney at the Southern Environmental Law Center, said in a statement. “Santee Cooper is moving ahead in restoring the Grainger site in the center of Conway and, at the same time, is cleaning up the region’s water resources.”

Conservation groups and Santee Cooper settled litigation in 2013 over coal ash stored at Grainger and the state-owned utility announced plans afterward to remove the pollution. Santee Cooper also has started removing ash from its Jefferies and Winyah sites. At Winyah, Santee Cooper has partnered with SEFA of Lexington for the construction of a facility that converts the coal ash to a form where it can be recycled for concrete.

Arsenic pollution at SCE&G’s Wateree plant on the Catawba-Wateree River near Columbia has also dropped significantly following that utility’s removal of coal ash from unlined pits at the site. The subsidiary of Scana Corp. has been removing coal ash from the site since 2012 under an agreement negotiated by the Southern Environmental Law Center on behalf of the Catawba Riverkeeper. Arsenic pollution at that site has dropped by 80 percent to 90 percent.

Boeing Co. increased production of its 787 Dreamliners to 12 a month earlier this year and says it eventually wants to boost that pace to 14, but a Bloomberg report casts doubt on when — or even if — that will happen.

"Fourteen a month is still where we're heading," Boeing CEO Dennis Muilenburg said during an investors conference last week. "And we haven't precisely defined the timing on that yet because it's dependent on" monthly deliveries.

The current assembly rate is the fastest for any wide-body plane, but Dreamliner orders have slowed — to a dozen through May compared to 45 for the same period a year ago.

The prospects of deliveries falling short of projections also worry aerospace experts.

"Analysts have questioned whether Boeing would speed 787 production amid slower economic growth in key markets such as China and pricing signals from the secondary market that suggest a glut of wide-body aircraft," Bloomberg reported. "But Boeing also must counter faster output planned by Airbus for two planes that compete with the Dreamliner, the A330neo and A350neo."

Barclays analyst Carter Copeland stated in a report that "the prospects for the 787 getting to 14/month from 12/month are declining for sure," Bloomberg reported.

Boeing, which makes the Dreamliner at its North Charleston campus and in Everett, Wash., has only said it plans to increase production to 14 a month by the end of this decade.

Small businesses with annual revenues of less than $10 million make up the vast majority of South Carolina's economy, a study by American Express and Dun & Bradstreet shows.

While the study aims to show the growing national impact of middle-market firms — those with annual revenues between $10 million and $1 billion — it points out South Carolina's dearth of such companies. Middle-market firms make up less than 1 percent of all companies in the state, according to the study. And that's after an 80 percent growth in such firms between 2011 and 2016. The study shows there are 2,017 middle-market companies in South Carolina.

By contrast, South Carolina's 214,315 small companies make up 99.1 percent of the state's businesses.

South Carolina has just 25 large companies, defined in the study as those with annual revenues topping $1 billion.

Nationally, the report shows middle-market firms are an increasingly important sector, accounting for 53 percent of job growth since 2011.

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