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Case No. 14-1693-EL-RDR, 14-1694-EL-AAM

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In the Matter of the Application of Ohio Power Company for approval of certain ~~accoun~~ accounting authority.

List of exhibits being filed: Volume IV

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Part IV

Environmental Protection Agency

40 CFR Part 131

Water Quality Standards Regulatory Revisions; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 131

[EPA–HQ–OW–2010–0606; FRL–9921–21–OW]

RIN 2040–AF16

Water Quality Standards Regulatory Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA updates the federal water quality standards (WQS) regulation to provide a better-defined pathway for states and authorized tribes to improve water quality and protect high quality waters. The WQS regulation establishes a strong foundation for water quality management programs, including water quality assessments, impaired waters lists, and total maximum daily loads, as well as water quality-based effluent limits in National Pollutant Discharge Elimination System (NPDES) discharge permits. In this rule, EPA is revising six program areas to improve the WQS regulation's effectiveness, increase transparency, and enhance opportunities for meaningful public engagement at the state, tribal and local levels. Specifically, in this rule EPA: Clarifies what constitutes an Administrator's determination that new or revised WQS are necessary; refines how states and authorized tribes assign and revise designated uses for individual water bodies; revises the triennial review requirements to clarify the role of new or updated Clean Water Act (CWA) section 304(a) criteria recommendations in the development of WQS by states and authorized tribes, and applicable WQS that must be reviewed triennially; establishes stronger antidegradation requirements to enhance protection of high quality waters and promotes public transparency; adds new regulatory provisions to promote the appropriate use of WQS variances; and clarifies that a state or authorized tribe must adopt, and EPA must approve, a permit compliance schedule authorizing provision prior to authorizing the use of schedules of compliance for water quality-based effluent limits (WQBELs) in NPDES permits. In total, these revisions to the WQS regulation enable states and authorized tribes to more effectively address complex water quality challenges, protect existing water quality, and facilitate environmental improvements. The final rule also leads to better understanding and proper use of available CWA tools by promoting transparent and engaged public participation. This action finalizes the WQS regulation revisions initially proposed by EPA on September 4, 2013.

DATES: This final rule is effective on October 20, 2015.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OW–2010–0606. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the Office of Water Docket Center, EPA/DC, William Jefferson Clinton West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20004. 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 Office of Water Docket Center is (202) 566–2426. To view docket materials, call ahead to schedule an appointment. Every user is entitled to copy 266 pages per day before incurring a charge. The Docket Center may charge $0.15 for each page over the 266-page limit, plus an administrative fee of $25.00.

FOR FURTHER INFORMATION CONTACT: Janita Aguirre, Standards and Health Protection Division, Office of Science and Technology (4305T), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington DC 20460; telephone number: (202) 566–1860; fax number: (202) 566–0409; email address: *WQSRegulatoryClarifications@epa.gov.*

SUPPLEMENTARY INFORMATION: The supplementary information section is organized as follows:

Table of Contents

I. General Information

A. Does this action apply to me?

The entities potentially affected by this rule are shown in the table below.

Category	Examples of potentially affected entities
States and Tribes.	States and authorized tribes responsible for administering or overseeing water quality programs.[1]
Industry	Industries discharging pollutants to waters of the United States.
Municipalities.	Publicly owned treatment works or other facilities discharging pollutants to waters of the United States.

This table is not exhaustive, but rather it provides a guide for entities that may be directly or indirectly affected by this action. Citizens concerned with water quality and other types of entities may also be interested in this rulemaking, although they might not be directly impacted. If you have questions

[1] Hereafter referred to as "states and authorized tribes." "State" in the CWA and this document refers to a state, the District of Columbia, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands. "Authorized tribes" refers to those federally recognized Indian tribes with authority to administer a CWA WQS program.

regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What is the statutory and regulatory history of the federal WQS regulation?

The Clean Water Act (CWA or the Act)—initially enacted as the Federal Water Pollution Control Act Amendments of 1972 (Pub. L. 92–500) and subsequent amendments—determined the basic structure in place today for regulating pollutant discharges into waters of the United States. The objective of the CWA is "to restore and maintain the chemical, physical, and biological integrity of the Nation's waters," and to achieve "wherever attainable, an interim goal of water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation in and on the water" (CWA sections 101(a) and 101(a)(2)).

The CWA establishes the basis for the water quality standards (WQS or standards) regulation and program. CWA section 303 addresses the development of state and authorized tribal WQS that serve the CWA objective for waters of the United States. The core components of WQS are designated uses, water quality criteria that support the uses, and antidegradation requirements. Designated uses establish the environmental objectives for a water body and water quality criteria [2] define the minimum conditions necessary to achieve those environmental objectives. The antidegradation requirements provide a framework for maintaining and protecting water quality that has already been achieved.

CWA section 301 establishes pollutant discharge restrictions for point sources. Specifically, it provides that "the discharge of any pollutant by any person shall be unlawful" except in compliance with the terms of the Act, including industrial and municipal effluent limitations specified under CWA sections 301 and 304 and "any more stringent limitation, including those necessary to meet water quality standards, treatment standards, or schedule of compliance, established pursuant to any [s]tate law or regulations."

The CWA gives states and authorized tribes discretion on how to control pollution from nonpoint sources. Although the CWA includes specific requirements for the control of pollution from certain discharges, state and authorized tribal WQS established pursuant to CWA section 303 apply to the water bodies themselves, regardless of the source(s) of pollution/pollutants. Thus, the WQS express the desired condition and level of protection for a water body, regardless of whether a state or authorized tribe chooses to place controls on nonpoint source activities, in addition to point source activities required to obtain permits under the CWA. Section 303(c) of the Act also requires that states and authorized tribes hold a public hearing to review their standards at least once every three years (*i.e.*, triennial review), and that EPA review and approve or disapprove any new or revised state and authorized tribal standards. Furthermore, if EPA disapproves a state's or authorized tribe's WQS under CWA sections 303(c)(3) and 303(c)(4)(A), or if the Administrator makes a determination under CWA section 303(c)(4)(B) that a new or revised WQS is necessary, EPA must propose and promulgate federal standards for a state or authorized tribe, unless the state or authorized tribe develops and EPA approves its own WQS first.

EPA established the core of the WQS regulation in a final rule issued in 1983. That rule strengthened provisions that had been in place since 1977 and codified them as 40 CFR part 131.[3] In support of the 1983 regulation, EPA issued a number of guidance documents, such as the *Water Quality Standards Handbook* (WQS Handbook),[4] that provide guidance on the interpretation and implementation of the WQS regulation and on scientific and technical analyses that are used in making decisions that would impact WQS. EPA also developed the *Technical Support Document for Water Quality-Based Toxics Control*[5] that provides additional guidance for implementing state and authorized tribal WQS.

EPA modified the 40 CFR part 131 regulation twice since 1983. First, in 1991 pursuant to section 518 of the Act, EPA added §§ 131.7 and 131.8 which extended to Indian tribes the opportunity to administer the WQS program and outlined dispute resolution mechanisms.[6] Second, in 2000, EPA finalized § 131.21(c)–(f), commonly known as the "Alaska Rule," which specifies that new and revised standards adopted by states and authorized tribes and submitted to EPA after May 30, 2000, become applicable standards for CWA purposes only when approved by EPA.[7]

In 1998, EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) to discuss and invite comment on over 130 aspects of the federal WQS regulation and program, with the goal of identifying specific changes that might strengthen water quality protection and restoration, facilitate watershed management initiatives, and incorporate evolving water quality criteria and assessment science into state and authorized tribal WQS programs.[8] Although EPA chose not to move forward with a rulemaking after the ANPRM, EPA identified a number of high priority issue areas for which the Agency developed guidance, provided technical assistance, and continued further discussion and dialogue to ensure more effective program implementation. This action is part of EPA's ongoing effort to clarify and strengthen the WQS program.

C. What environmental issues do the final changes to the federal WQS regulation address?

Since EPA first established the WQS regulation in 1983, the regulation has acted as a powerful force to prevent pollution and improve water quality by providing a foundation for a broad range of water quality management programs. Since 1983, however, diverse and complex challenges have arisen, including new types of contaminants, pollution stemming from multiple sources, extreme weather events, hydrologic alteration, and climate change-related impacts. These challenges necessitate a more effective, flexible and practicable approach for the implementation of WQS and protecting water quality. Additionally, extensive experience with WQS implementation by states, authorized tribes, and EPA revealed a need to update the regulation to help meet these challenges.

This rulemaking revises the requirements in six program areas: (1) Administrator's determination that new or revised WQS are necessary, (2) designated uses, (3) triennial reviews, (4) antidegradation, (5) WQS variances, and (6) permit compliance schedule authorizing provisions.

The provisions related to designated uses help states and authorized tribes restore and maintain resilient and

[2] Under CWA section 304(a), EPA publishes recommended water quality criteria guidance that consists of scientific information regarding concentrations of specific chemicals or levels of parameters in water that protect aquatic life and human health. CWA section 303(c) refers to state and authorized tribal water quality criteria that are subject to EPA review and approval or disapproval.

[3] 54 FR 51400 (November 8, 1983).

[4] First edition, December 1983; second edition, EPA 823–B–94–005a, August 1994.

[5] First edition, EPA 440/4–85–032, September 1985; revised edition, EPA 505/2–90–001, March 1991.

[6] 56 FR 64893 (December 12, 1991).

[7] 65 FR 24641 (April 27, 2000).

[8] 63 FR 36742 (July 7, 1998).

robust ecosystems by requiring that states and authorized tribes evaluate and adopt the highest attainable use when changing designated uses. The rule provides clearer expectations for when an analysis of attainability of designated uses is or is not required. Such clarity allows for better and more transparent communication among EPA, states, authorized tribes, stakeholders and the public about the designated use revision process, and the appropriate level of protection necessary to meet the purposes of the CWA.

This rule ensures better protection and maintenance of high quality waters that have better water quality than minimally necessary to support propagation of fish, shellfish, and wildlife, and recreation in and on the water. Through protection of habitat, water quality, and aquatic community structure, high quality waters are better able to resist stressors, such as atmospherically deposited pollutants, emerging contaminants, severe weather events, altered hydrology, or other effects resulting from climate change. This rule strengthens the evaluation used to identify and manage high quality waters and increases the opportunities for the public and stakeholders to be involved in the decision-making process. Specifically, there must be a transparent, public, robust evaluation before any decision is made to allow lowering of high quality water. Thus, this rule will lead to better protection of high quality waters.

The rule addresses WQS variances and permit compliance schedules, which are two CWA tools which can be used where WQS are not being attained. The provisions related to WQS variances allow states and authorized tribes to address water quality challenges in a transparent and predictable way. The rule also includes provisions for authorizing the use of permit compliance schedules to ensure that a state or authorized tribal decision to allow permit compliance schedules includes public engagement and transparency. These two tools help states and authorized tribes focus on making incremental progress in improving water quality, rather than pursuing a downgrade of the underlying water quality goals through a designated use change, when the current designated use is difficult to attain.

Lastly, the Administrator's determination and triennial review provisions in this rule promote public transparency and allow for effective communication among EPA, states, authorized tribes, and stakeholders to ensure WQS continue to be consistent with the CWA and EPA's implementing regulation. Meaningful and transparent involvement of the public is an important component of triennial review when making decisions about whether and when criteria will be adopted or revised to protect designated uses. The rule provides more clearly defined and transparent requirements, so that states and authorized tribes consider the latest science as reflected in the CWA section 304(a) criteria recommendations, and the public understands the decisions made.

D. How was this final rule developed?

In developing this rule, EPA considered the public comments and feedback received from stakeholders. EPA provided a 120-day public comment period after the proposed rule was published in the **Federal Register** on September 4, 2013.[9] In addition, EPA held two public webinars, a public meeting, and a tribal consultation to discuss the contents of the proposed rule and answer clarifying questions in order to allow the public to submit well-informed comments.

Over 150 organizations and individuals submitted comments on a range of issues. EPA also received 2,500 letters from individuals associated with mass letter writing campaigns. Some comments addressed issues beyond the scope of the proposed rulemaking. EPA did not expand the scope of the rulemaking or make regulatory changes to address the substance of these comments. In each section of this preamble, EPA discusses certain public comments so that the public is fully aware of its position. For a full response to these and all other comments, see EPA's Response to Comments document in the official public docket.

In addition, EPA met with all stakeholders who requested time to discuss the contents of the proposed rule. Such discussions occurred with members of state and tribal organizations and the environmental community. Records of each meeting are included in the official public docket.

E. When does this action take effect?

This regulation is effective October 20, 2015. For judicial review purposes, this rule is promulgated as of 1 p.m. EST (Eastern Standard Time) on the effective date, which will be 60 days after the date of publication of the rule in the **Federal Register**.

States and authorized tribes are subject to the requirements of this final rule on the effective date of the rule. EPA's expectation is that, where a new or revised requirement necessitates a change to state or authorized tribal WQS, such revisions will occur within the next triennial review that the state or authorized tribe initiates after publication of the rule.

As a general matter, when EPA reviews new or revised state or authorized tribal WQS it reviews the provisions to determine whether they are consistent with the CWA and regulation applicable at the time of EPA's review. However, for a short period of transition, EPA will review the provisions and approve or disapprove based on whether they are consistent with the CWA and the relevant part 131 regulation that is in effect prior to the final rule's effective date if (1) they were submitted before the effective date of this final rule or (2) if a state or authorized tribe has held its public hearing(s) and the public comment period has closed before the effective date of this rule and the state or authorized tribe has submitted the new or revised WQS within nine months of the effective date of this final rule. This approach is reasonable for the transition period because EPA recognizes that states and authorized tribes may have invested a significant amount of resources drafting new or revised WQS for the public to comment on without the benefit of knowing EPA's final rule requirements and the state or authorized tribe may not have had sufficient notice to alter the WQS prior to submission to EPA. It would be inefficient and unfair for the state or authorized tribe to have to re-propose and re-start the rulemaking process when it can address the issue in the next triennial review consistent with the final rule. In addition, changing the applicable federal standards that will be basis of EPA's review after the public has put in the effort to provide constructive comments to the state or authorized tribe would be inefficient and could render the comments obsolete. Nine months is a reasonable timeframe to accommodate states and authorized tribes that have legislative processes such that new or revised WQS cannot be submitted to EPA until the legislature has passed the regulation at its soonest legislative session after close of the public comment period. Except for the circumstances outlined in this paragraph regarding the transition period, EPA will work with states and authorized tribes to ensure that new or revised WQS meet the requirements of the final rule.

In the event that a court sets aside any portion of this rule, EPA intends for the remainder of the rule to remain in effect.

[9] See Water Quality Standards Regulatory Clarifications, 78 FR 54517 (September 4, 2013).

II. Rule Revisions Addressed in This Rule

EPA provides a comparison document showing the revisions made by this final rule, and a second document showing the revisions made between the proposed and final rule. EPA has posted both documents at *http://water.epa.gov/lawsregs/lawsguidance/wqs_index.cfm.*

A. Administrator's Determinations That New or Revised WQS Are Necessary

What does this rule provide and why?

Open communication among states, tribes and EPA facilitates the sharing of information to ensure that WQS continue to adequately protect waters as new challenges arise. However, the public has occasionally mistaken such communication from EPA for a "determination" by the Administrator that new or revised WQS are necessary under CWA section 303(c)(4)(B) (hereafter referred to as "Administrator's determination").[10]

With the clarification provided by this rule, stakeholders and the public can readily distinguish Administrator's determinations from routine EPA communications on issues of concern and recommendations regarding the scope and content of state and authorized tribal WQS. This rule minimizes the potential for stakeholders to misunderstand EPA's intent with its communications and allows EPA to provide direct and transparent feedback. It will also preserve limited resources that would otherwise be spent resolving the confusion through litigation.

An Administrator's determination is a powerful tool, and this rule ensures that it continues to be used purposefully and thoughtfully. This rule contains two requirements related to an Administrator's determination at § 131.22(b). The first requirement provides that, in order for a document to constitute an Administrator's determination, it must be signed by the Administrator or duly authorized delegate. The second requirement is that such a determination must include a statement that the document is an Administrator's determination for purposes of section 303(c)(4)(B) of the Act. This requirement makes clear that this provision applies to Administrator's determinations made under CWA section 303(c)(4)(B) rather than determinations made under CWA section 303(c)(4)(A).

Section 303(c)(4) of the Act provides two different scenarios under which the Administrator has the authority to "promptly prepare and publish proposed regulations setting forth a revised or new water quality standard for the navigable waters involved" following some sort of determination. Section 303(c)(4)(A) of the Act gives EPA the authority to propose regulations where states or authorized tribes have submitted new or revised WQS that the Administrator "determines" are not consistent with the Act. In this instance, EPA disapproves new or revised WQS and specifies the changes necessary to meet CWA requirements. If a state or authorized tribe fails to adopt and submit the necessary revisions within 90 days after notification of the disapproval determination, EPA must promptly propose and promulgate federal WQS as specified in CWA section 303(c)(4)(A) and 40 CFR 131.22(a). This action does not address or affect this authority.

Absent state or authorized tribal adoption or submission of new or revised WQS, section 303(c)(4)(B) of the CWA gives EPA the authority to determine that new or revised WQS are necessary to meet the requirements of the Act. Once the Administrator makes such a determination, EPA must promptly propose regulations setting forth new or revised WQS for the waters of the United States involved, and must then promulgate such WQS, unless a state or authorized tribe adopts and EPA approves such WQS first.

Commenters expressed concern that the proposed rule was not clear with respect to which of these authorities was addressed in this rule. EPA's final rule makes clear that these requirements only refer to Administrator's determinations under CWA section 303(c)(4)(B).

Based on comments, EPA reviewed the use of the term "states" throughout the regulation and found that, in § 131.22(b), this term did not accurately describe the scope of waters for which the CWA provides authority to the EPA Administrator. Thus, consistent with CWA section 303(c)(4), this rule provides that the Administrator may propose and promulgate a regulation applicable to one or more "navigable waters," as that term is defined in CWA section 502(7) after determining that new or revised WQS are necessary to meet the requirements of the CWA. Consistent with the statute's plain language, this authority applies to all navigable waters located in any state or in any area of Indian country.[11]

What did EPA consider?

EPA considered finalizing the revision to § 131.22(b) as proposed. However, EPA decided it was important to clarify that this provision only addresses Administrator's determinations made pursuant to section 303(c)(4)(B) of the Act, which was not clear given the comments received. EPA also considered foregoing revisions to § 131.22(b) altogether. However, this option would not meet EPA's policy objective, described previously, which many commenters supported.

What is EPA's position on certain public comments?

Some commenters requested that EPA clarify whether this revision will affect the petition process under section 553(e) of the Administrative Procedure Act (APA) (5 U.S.C. 553(e)). This action does not affect the public's ability to petition EPA to issue, amend, or repeal a rule. Nor does this action affect the Agency's obligations for responding to an APA petition or the ability of a petitioner to challenge the Agency for unreasonable delay in responding to a petition. In the event that the Administrator grants a petition for WQS rulemaking and makes an Administrator's determination that new or revised WQS are necessary, this provision does not affect the obligation the Agency has to promptly propose and promulgate federal WQS.

Some commenters requested that EPA clarify how the Administrator delegates authority. The laws, Executive Orders, and regulations that give EPA its authority typically, but not always, indicate that "the Administrator" shall or may exercise certain authorities. In order for other EPA management officials to act on behalf of the Administrator, the Administrator must delegate the authority granted by Congress or the Executive Branch. The Administrator may do so by regulation or through the Agency's delegation process by signing an official letter that is then maintained as a legal record of authority.

B. Designated Uses

What does this rule provide and why?

CWA section 303(c)(2)(A) requires that new or revised WQS shall consist

[10] A listing of Administrator's determinations that new or revised WQS are necessary to meet the requirements of the CWA pursuant to section 303(c)(4)(B) can be found at: *http://water.epa.gov/scitech/swguidance/standards/wqsregs.cfm#federal* under the heading "Federal Clean Water Act Determinations that New or Revised Standards Are Necessary." EPA intends to post future Administrator's determinations pursuant to CWA section 303(c)(4)(B) to its Web site.

[11] Indian country is defined at 18 U.S.C. 1151. A prior example of federally promulgated WQS in Indian country can be found at 40 CFR 131.35, federally promulgated WQS for the Colville Confederated Tribes Indian Reservation (54 FR 28625, July 6, 1989).

of designated uses and water quality criteria based on such uses. It also requires that such WQS shall protect the public health or welfare, enhance the quality of the water, and serve the purposes of the Act. Section 101(a) of the CWA provides that the ultimate objective of the Act is to restore and to maintain the chemical, physical, and biological integrity of the Nation's waters. The national goal in CWA section 101(a)(2) is water quality that provides for the protection and propagation of fish, shellfish, and wildlife and for recreation in and on the water "wherever attainable." EPA's WQS regulation at 40 CFR part 131, specifically §§ 131.10(j) and (k), interprets and implements these provisions through requirements that WQS protect the uses specified in CWA section 101(a)(2) unless states and authorized tribes show those uses are unattainable through a use attainability analysis (UAA) consistent with EPA's regulation, effectively creating a rebuttable presumption of attainability.[12] This underlying requirement remains unchanged by this rule. EPA discussed the 1983 requirements and the rebuttable presumption in the preamble to the proposed rule as background discussion of the existing regulatory requirements. The revisions to § 131.10 establish the additional requirement to adopt the highest attainable use (HAU) after demonstrating that CWA section 101(a)(2) uses are not attainable.

CWA section 303(c)(2)(A) also requires states and authorized tribes to establish WQS "taking into consideration their use and value" for a number of purposes, including those addressed in section 101(a)(2) of the Act. EPA's final 1983 regulation at § 131.10(a) implements this provision by requiring that the "[s]tate must specify appropriate water uses to be achieved and protected" and that the "classification of the waters of the [s]tate must take into consideration the use and value of water for public water supplies, protection and propagation of fish, shellfish and wildlife, recreation in and on the water, agricultural, industrial, and other purposes including navigation."

The revisions to the designated use requirements improve the process by which states and authorized tribes designate and revise uses to better help restore and maintain resilient water quality and robust aquatic ecosystems. The revisions reduce potential confusion and conflicting interpretations of the regulatory requirements for establishing designated uses that can hinder environmental progress. Designated uses drive state and authorized tribal criteria development and water quality management decisions. Therefore, clear and accurate designated uses are essential in maintaining the actions necessary to restore and protect water quality and to meet the goals and objectives of the CWA.

The CWA distinguishes between two broad categories of uses: uses specified in section 101(a)(2) of the Act and uses specified in section 303(c)(2) of the Act. For the purposes of this final rule, the phrase "uses specified in section 101(a)(2) of the Act" refers to uses that provide for the protection and propagation of fish,[13] shellfish, and wildlife, and recreation in and on the water, as well as for the protection of human health when consuming fish, shellfish, and other aquatic life. A "sub-category of a use specified in section 101(a)(2) of the Act" refers to any use that reflects the subdivision of uses specified in section 101(a)(2) of the Act into smaller, more homogenous groups for the purposes of reducing variability within the group.[14] A "non-101(a)(2) use" is a use that is not related to the protection or propagation of fish, shellfish, wildlife or recreation in or on the water. Non-101(a)(2) uses include those listed in CWA section 303(c)(2), but not those listed in CWA section 101(a)(2), including use for public water supply, agriculture, industry, and navigation.

For uses specified in section 101(a)(2) of the Act, this rule clarifies when a UAA is and is not required. This rule also makes clear that once a state or authorized tribe has rebutted the presumption of attainability by demonstrating through a required UAA that a use specified in section 101(a)(2) of the Act is not attainable, it must adopt the HAU, as defined in this rule. The HAU requirement supports adoption of states' and authorized tribes' WQS to enhance the quality of the water and to serve the purposes of the Act, including ensuring water quality that provides for uses described in CWA section 101(a)(2) where attainable and to restore and maintain the chemical, physical and biological integrity of the Nation's waters.

For non-101(a)(2) uses, this rule provides that a UAA is not required when a state or authorized tribe removes or revises a non-101(a)(2) use, but clarifies that states and authorized tribes must still submit documentation consistent with CWA section 303(c)(2)(A) to support the state or authorized tribe's action. This requirement recognizes that states' and authorized tribes' decisions about non-101(a)(2) uses must be consistent with the statute and transparent to the public and EPA. This rule also provides a regulatory definition for a non-101(a)(2) use at § 131.3(q). Non-101(a)(2) uses are separate and distinct from uses specified in CWA section 101(a)(2) and sub-categories of such uses.

To clarify when a UAA is and is not required, this rule revises § 131.10(g) and (j) so that when the provisions are read together, it is clear that the factors at § 131.10(g) are only required to be considered when the state or authorized tribe must conduct a UAA under § 131.10(j). In addition, this rule revises § 131.10(k) into new § 131.10(k)(1) and (2) to eliminate a possible contradiction with § 131.10(j)(2), as described in the preamble to the proposed rule.[15]

Section 131.10(j) describes when a UAA is required. Section 131.10(k) specifies when a UAA is not required. Further, the definition of a UAA at § 131.3(g) says that a UAA "is a structured scientific assessment of the factors affecting the attainment of the use which may include physical, chemical, biological, and economic factors as described in § 131.10(g)." Section 131.10(g) provides that states and authorized tribes may remove a designated use if they can demonstrate that attaining a designated use is not feasible because of one of six specified factors.

EPA revises § 131.10(j)(1) to clarify that a UAA is required whenever a state or authorized tribe designates uses for the first time that do not include the uses specified in section 101(a)(2) of the Act. Section 131.10(j)(1) also clarifies that a UAA is required where a state or authorized tribe has previously designated uses that do not include the

[12] EPA's 1983 regulation and "the rebuttable presumption stemming therefrom" have been upheld as a "permissible construction of the statute" (*Idaho Mining Association v. Browner*, 90 F. Supp. 2d 1078, 1097–98 (D. Idaho 2000)).

[13] To achieve the CWA's goal of "wherever attainable . . . protection and propagation of fish . . ." all aquatic life, including aquatic invertebrates, must be protected because they are a critical component of the food web.

[14] A sub-category of a use specified in section 101(a)(2) of the Act is not necessarily less protective than a use specified in section 101(a)(2) of the Act. For example, a cold water aquatic life use is considered a use sub-category, but provides "for the protection and propagation of fish, shellfish and wildlife," consistent with CWA section 101(a)(2). On the other hand, a secondary contact recreation use (*i.e.*, a use, such as wading or boating, where there is a low likelihood of full body immersion in water or incidental ingestion of water) is considered a use sub-category, but does not provide "for recreation in and on the water," consistent with CWA section 101(a)(2).

[15] See 78 FR 54525 (September 4, 2013).

uses specified in section 101(a)(2) of the Act.[16] EPA revises § 131.10(j)(2) to clarify that a UAA is required when removing or revising a use specified in section 101(a)(2) of the Act as well as when removing or revising a sub-category of such a use. These revisions also clarify that when adopting a sub-category of a use specified in section 101(a)(2) of the Act with less stringent criteria, a UAA is only required when the criteria are less stringent than the previously applicable criteria. EPA made corresponding revisions to § 131.10(g) to explicitly reference § 131.10(j). This rule also includes editorial changes to § 131.10(g) that are not substantive in nature. Lastly, EPA establishes a new § 131.10(k)(1) and (2) to explain when a UAA is not required.

To ensure that states and authorized tribes adopt WQS that continue to serve the Act's goal of water quality that provides for the uses specified in section 101(a)(2) of the CWA to the extent attainable and enhance the quality of the water, this rule revises § 131.10(g) to provide that where states and authorized tribes adopt new or revised WQS based on a required UAA, they must adopt the HAU as defined at § 131.3(m). These new requirements make clear that states and authorized tribes may remove unattainable uses, but they must retain and designate the attainable use(s). The final regulation does not prohibit states and authorized tribes from removing a designated use specified in CWA section 101(a)(2) or a sub-category of such a use, altogether, where demonstrated to be unattainable. For example, a state or authorized tribe may remove an aquatic life use if it can demonstrate through a UAA that no aquatic life use or sub-category of aquatic life use is attainable. EPA expects such situations to be rare; however to clarify that this outcome is possible, EPA adds a sentence to the definition of HAU at § 131.3(m) to make explicit that where the state or authorized tribe demonstrates the relevant use specified in section 101(a)(2) of the Act and sub-categories of such a use are not attainable, there is no required HAU to be adopted. If a state or authorized tribe removes the designated use, altogether, and in the same action adopts another designated use in a different broad use category (*e.g.*, agricultural use, recreational use), it may appear as though the state or authorized tribe intends the newly adopted use to be the HAU. In fact, this is a separate state or tribal decision in the same rulemaking.

The concept of HAU is fundamental to the WQS program. Adopting a use that is less than the HAU could result in the adoption of water quality criteria that inappropriately lower water quality and could adversely affect aquatic ecosystems and the health of the public recreating in and on such waters. For example, a state or authorized tribe may be able to demonstrate that a use supporting a particular class of aquatic life is not attainable. However, if some less sensitive aquatic organisms are able to survive at the site under current or attainable future conditions, the state's or authorized tribe's WQS are not continuing to serve the goals of the CWA by removing the aquatic life use designation and applicable criteria altogether without adopting an alternate CWA section 101(a)(2) use or sub-category of such a use that is feasible to attain, and the criteria that protect that use. EPA's regulation at §§ 131.5(a)(2), 131.6(c), and 131.11(a) explicitly requires states and authorized tribes to adopt water quality criteria that protect designated uses.

Commenters expressed concern that the proposed definition of HAU used overly subjective terminology that would make it difficult for states and authorized tribes to adopt an HAU that would not be challenged by stakeholders. The definition of HAU at § 131.3(m) includes specific terms to ensure that the resulting HAU is clear to states, authorized tribes, stakeholders and the public.

First, the word "modified" makes clear that when adopting the HAU, the state or authorized tribe is adopting a different use within the same broad CWA section 101(a)(2) use category, if any such use is attainable. For example, if a state or authorized tribe removes a warm water aquatic life use, then the HAU is a modified version of the warm water aquatic life use, such as a "limited warm water aquatic life use." The definition makes clear that states and authorized tribes are not required to determine whether one broad use category is better than another (*e.g.*, to determine that a recreation use is better than an aquatic life use).

Second, EPA adds the phrase "based on the evaluation of the factor(s) in § 131.10(g) that preclude(s) attainment of the use and any other information or analyses that were used to evaluate attainability" to the final HAU definition to be clear that the HAU is the attainable use that results from the process of determining what is not attainable. For example, where the state or authorized tribe demonstrates that a use cannot be attained due to substantial and widespread economic and social impacts, the state or authorized tribe may then determine the HAU by considering the use that is attainable without incurring costs that would cause a substantial and widespread economic and social impact consistent with § 131.10(g)(6). Although the definition continues to include the terms "highest" and "closest to," which some commenters said were subjective terms, the new definition does not necessarily mean that the use with the most numerically stringent criteria must be designated as the HAU. The CWA does not require states and authorized tribes to adopt designated uses to protect a level beyond what is naturally occurring in the water body. Therefore, a state's or authorized tribe's determination of the HAU must take into consideration the naturally expected condition for the water body or waterbody segment. For example, Pacific Northwest states provide specific levels of protection for different life stages of salmonids. While the different life stages require different temperature criteria, the designated use with the most numerically stringent temperature criterion may not be required under § 131.11(a) to protect the HAU, if the life stage that temperature criterion protects does not naturally occur in that water body or waterbody segment.

When conducting a UAA and soliciting input from the public, states and authorized tribes need to consider not only what is currently attained, but also what is attainable in the future after achievable gains in water quality are realized. EPA recommends that such a prospective analysis involve the following:

- Identifying the current and expected condition for a water body;
- Evaluating the effectiveness of best management practices (BMPs) and associated water quality improvements;
- Examining the efficacy of treatment technology from engineering studies; and
- Using water quality models, loading calculations, and other predictive tools.

The preamble to the proposed rule also provided several examples of how states and authorized tribes can articulate the HAU. These examples include using an existing designated use framework, adopting a new statewide sub-category of a use, or adopting a new sub-category of a use that uniquely recognizes the limiting condition for a specific water body (*e.g.*, aquatic life limited by naturally high levels of copper).

One example of where a state adopted new statewide sub-categories to protect

[16] This provision includes situations where a state or authorized tribe adopts for the first time, or previously designated, only non-101(a)(2) uses.

the highest attainable use was related to a class of waters the state defines as "effluent dependent waters." The state conducted a UAA to justify the removal of the aquatic life use in these waters. It was not feasible for these waters to attain the same aquatic life assemblage expected of waters assigned the statewide aquatic life use. The state identified the highest attainable aquatic life use for these waters and created two new sub-categories (effluent-dependent fisheries and effluent-dependent non-fish bearing waters) with criteria that are sufficiently protective of these uses. These EPA-approved sub-categories reflect the aquatic life use that can be attained in these waters, while still protecting the effluent dependent aquatic life.

Some commenters expressed concern with the difficulty of articulating a specific HAU because doing so may require additional analyses. Where this may be the case, an alternative method of articulating the HAU can be for a state or authorized tribe to designate for a water body a new or already established, broadly defined HAU (*e.g.*, limited aquatic life use) and the criteria associated with the best pollutant/parameter levels attainable based on the information or analysis the state or authorized tribe used to evaluate attainability of the designated use. This is reasonable because the state or authorized tribe is essentially articulating that the HAU reflects whatever use is attained when the most protective, attainable criteria are achieved.

One example where a state used this alternative method involved adoption of a process by which the state can tailor site-specific criteria to protect the highest attainable use as determined by a UAA. EPA approved the state's adoption of a broad "Limited Use" and the subsequent adoption of a provision to allow the development of site-specific criteria for certain pollutants to protect that use. The "Limited Use" shares the same water quality criteria as the state's full designated use for recreation and fish and wildlife protection "except for any site-specific alternative criteria that have been established for the water body." Such site-specific criteria are limited to numeric criteria for nutrients, bacteria, dissolved oxygen, alkalinity, specific conductance, transparency, turbidity, biological integrity, or pH. The state restricts application of the "Limited Use" to waters with human induced physical or habitat conditions that prevent attainment of the full designated use for recreation and fish and wildlife protection, and to either (1) wholly artificial waters, or (2) altered water bodies dredged and filled prior to November 28, 1975. Through this process, the state is able to articulate the HAU by identifying the most protective, attainable criteria that can be achieved.

Where a state or authorized tribe does not already have a statewide use in their regulation that is protective of the HAU, the state or authorized tribe will need to find an approach that meets the requirements of the CWA and § 131.10(g). States and authorized tribes are not limited by the examples described in this section and can choose a different approach that aligns with their specific needs, as long as their preferred approach is protective of the HAU and is consistent with the CWA and § 131.10.[17]

As an example of how a UAA informs the identification of the HAU, consider a state or authorized tribe with a designated aquatic life use and associated dissolved oxygen criterion. The state or authorized tribe determines through a UAA that a particular water body cannot attain its designated aquatic life use due to naturally occurring dissolved oxygen concentrations that prevent attainment of the use (*i.e.*, the use is not attainable pursuant to § 131.10(g)(1)). Such an analysis also shows that the low dissolved oxygen concentrations are not due to anthropogenic sources, but rather due to the bathymetry of the water body. The state or authorized tribe then evaluates what level of aquatic life use is attainable in light of the naturally low dissolved oxygen concentration, as well as any data that were used to evaluate attainability (*e.g.*, biological data). The state or authorized tribe concludes that the naturally low dissolved oxygen concentration precludes attainment of the full aquatic life use, and requires an alternative dissolved oxygen criterion that protects the "highest" but limited aquatic life that is attainable. Once this analysis is complete and fully documented in the UAA, the state or authorized tribe would then designate the HAU and adopt criteria to protect that use.

To clarify what is required when a state or authorized tribe adopts new or revised non-101(a)(2) uses, this rule finalizes a new paragraph (3) at § 131.10(k) to specify that states and authorized tribes are not required to conduct a UAA whenever they wish to remove or revise a non-101(a)(2) use, but must meet the requirements in § 131.10(a). This rule defines a non-101(a)(2) use at § 131.3(q) as: "any use unrelated to the protection and propagation of fish, shellfish, wildlife or recreation in or on the water." While the CWA specifically calls out the protection and propagation of fish, shellfish, and wildlife and recreation in and on the water as the national goal, wherever attainable, this does not mean that non-101(a)(2) uses are not important. This rule revises § 131.10(a) to be explicit that where a state or authorized tribe is adopting new or revised designated uses other than the uses specified in section 101(a)(2) of the Act, or removing designated uses, it must submit documentation justifying how its consideration of the use and value of water for those uses listed in § 131.10(a) appropriately supports the state's or authorized tribe's action. EPA refers to this documentation as a "use and value demonstration." These requirements are consistent with EPA's previously existing regulation at §§ 131.10(a)[18] and 131.6.[19] A UAA can also be used to satisfy the requirements at § 131.10(a).

EPA encourages states and authorized tribes to work closely with EPA when developing a use and value demonstration. States and authorized tribes must consider relevant provisions in § 131.10, including downstream protection (§ 131.10(b)) and existing uses of the water (§ 131.10(h)(1)). EPA recommends states and authorized tribes also consider a suite of other factors, including, but not limited to:

• Relevant descriptive information (*e.g.*, identification of the use that is under consideration for removal, location of the water body/waterbody

[17] Section 131.10(c) provides that states and authorized tribes "*may* adopt sub-categories of a use. . ." (emphasis added). This provision generally allows states and authorized tribes to adopt sub-categories of the uses specified in the CWA. This rule is finalizing revisions to § 131.10(g) to specify that when a state or authorized tribe conducts a UAA required by § 131.10(j), and the state or authorized tribe revises its WQS to something other than a use specified in section 101(a)(2) of the Act, the state or authorized tribe must adopt the highest attainable modified aquatic life, wildlife, and/or recreation use (*i.e.*, a sub-category of an aquatic life, wildlife, and/or recreation use). Where a UAA is not required by § 131.10(j), the state or authorized tribe retains discretion to choose whether to adopt sub-categories of uses per § 131.10(c).

[18] Section 131.10(a) already provided that states and authorized tribes "must specify appropriate water uses to be achieved and protected" and that the "classification of the waters of the [s]tate must take into consideration the use and value of water for public water supplies, protection and propagation of fish, shellfish and wildlife, recreation in and on the water, agricultural, industrial, and other purposes including navigation").

[19] Section 131.6(a) and (b) already provided that states and authorized tribes must submit to EPA for review "use designations consistent with the provisions of sections 101(a)(2) and 303(c)(2) of the Act" and "[m]ethods used and analyses conducted to support WQS revisions."

segment, overview of land use patterns, summary of available water quality data and/or stream surveys, physical information, information from public comments and/or public meetings, anecdotal information, etc.),

• Attainability information (*i.e.*, the § 131.10(g) factors as described previously, if applicable),

• Value and/or benefits (including environmental, social, cultural, and/or economic value/benefits) associated with either retaining or removing the use, and

• Impacts of the use removal on other designated uses.

As an example of what a use and value demonstration for a non-101(a)(2) use can look like, consider a small water body that a state or authorized tribe generically designated as a public water supply as part of a statewide action. The state or authorized tribe decides there is no use and value in retaining such a use for that water body. The state or authorized tribe could provide the public and EPA with documentation that public water supply is not an existing use (*e.g.*, there is no evidence that the water body was used for this purpose and the water quality does not support this use); the nearby population uses an alternative drinking water supply; and projected population trends suggest that the current supply is sufficient to accommodate future growth. States and authorized tribes must make this documentation available to the public prior to any public hearing, and submit it to EPA with the WQS revision.

What did EPA consider?

In developing this rule, EPA considered foregoing the revisions to § 131.10(g), (j), and (k), but this option would not clarify when a UAA is or is not required and thus not accomplish the Agency's objectives. EPA considered finalizing the revisions to § 131.10(g), (j), and (k)(1) and (2) as proposed; however, in response to comments received, EPA made revisions to better accomplish its objectives.

EPA considered foregoing the HAU requirement at § 131.10(g), but this option would not support the adoption of WQS that continue to serve the purposes of the Act and enhance the quality of the water. EPA also considered finalizing the requirement as proposed but not finalizing a regulatory definition; however, the absence of a regulatory definition could lead to confusion and hinder environmental protection.

EPA considered not specifying what is required when removing or revising a non-101(a)(2) use in the final rule; however, multiple commenters indicated that EPA's proposed rule only specified that a UAA is not required to remove or revise a non-101(a)(2) use and did not specify what is required. Given the confusion about existing requirements, EPA decided to make the requirement explicit in § 131.10(a) and (k)(3).

What is EPA's position on certain public comments?

Numerous commenters disagreed with EPA's position that the consumption of aquatic life is a use specified in section 101(a)(2) of the Act and requested that EPA document the rationale for this position. Based on the CWA section 303(c)(2)(A) requirement that WQS protect public health, EPA interprets the uses under section 101(a)(2) of the Act to mean that not only can fish and shellfish thrive in a water body, but when caught, they can also be safely eaten by humans.[20]

EPA first articulated this interpretation in the 1992 National Toxics Rule.[21] For example, EPA specified that all waters designated for even minimal aquatic life protection (and therefore a potential fish and shellfish consumption exposure route) are protected for human health. EPA also described its interpretation in the October 2000 Human Health Methodology.[22] Consistent with this interpretation, most states have adopted human health criteria as part of their aquatic life uses, as the purpose of the criteria is to limit the amount of a pollutant in aquatic species prior to consumption by humans. However, states and authorized tribes may also choose to adopt human health criteria as part of their recreational uses, recognizing that humans will consume fish and shellfish after fishing, which many states consider to be a recreational use. EPA leaves this flexibility to states and authorized tribes as long as the waters are protecting humans from adverse effects of consuming aquatic life, unless the state or authorized tribe has shown that consumption of aquatic life is unattainable consistent with EPA's regulation.

EPA also received comments requesting clarification on existing uses. EPA notes that in addressing these comments, EPA is not reopening or changing the regulatory provision at § 131.10(h)(1). The proposed change to § 131.10(g) simply referred back to the requirement that is housed in § 131.10(h)(1) and was not intended to change requirements regarding existing uses. This is also the case in the final rule. The WQS regulation at § 131.3(e) defines an existing use as "those uses actually attained in the water body on or after November 28, 1975, whether or not they are included in the water quality standards." EPA provided additional clarification on existing uses in the background section of the proposed preamble,[23] as well as in a September 2008 letter from EPA to the State of Oklahoma.[24] Specifically, EPA explained that existing uses are known to be "actually attained" when the use has actually occurred *and* the water quality necessary to support the use has been attained. EPA recognizes, however, that all the necessary data may not be available to determine whether the use actually occurred or the water quality to support the use has been attained. When determining an existing use, EPA provides substantial flexibility to states and authorized tribes to evaluate the strength of the available data and information where data may be limited, inconclusive, or insufficient regarding whether the use has occurred and the water quality necessary to support the use has been attained. In this instance, states and authorized tribes may decide that based on such information, the use is indeed existing.

Some commenters expressed concern that this interpretation supports the removal of a designated use in a situation where the use has actually occurred but the water quality necessary to protect the use has never been attained, as well as in a situation where the water quality has been attained but the use has not actually occurred. Such an interpretation may be contrary to a state's or authorized tribe's environmental restoration efforts or water quality management goals. For example, a state or authorized tribe may designate a highly modified water body for primary contact recreation even though the water quality has never been attained to support such a use. In this situation, if the state or authorized tribe exercises its discretion to recognize such an existing use, then consistent with EPA's regulation the designated use may not be removed.

[20] *http://water.epa.gov/scitech/swguidance/standards/upload/2000_10_31_standards_shellfish.pdf.*

[21] 57 FR 60859 (December 22, 1992). See also 40 CFR 131.36.

[22] *http://water.epa.gov/scitech/swguidance/standards/criteria/health/methodology/index.cfm; Methodology for Deriving Ambient Water Quality Criteria for the Protection of Human Health,* see pages 4–2 and 4–3.

[23] 78 FR 54523 (September 4, 2013).

[24] *http://water.epa.gov/scitech/swguidance/standards/upload/Smithee-existing-uses-2008-09-23.pdf.*

If a state or authorized tribe chooses not to recognize primary contact recreation as an existing use in this same situation, the state or authorized tribe still must conduct a UAA to remove the primary contact use. The state or authorized tribe may only remove the primary contact recreation use if the use is not an existing use or if more stringent criteria are being added; the use cannot be attained by implementing effluent limits required under sections 301(b) and 306 of the Act and by implementing cost-effective and reasonable best management practices for nonpoint source control (§ 131.10(h)(1) and(2)); and the state or authorized tribe can demonstrate that one of the factors listed at § 131.10(g) precludes attainment of the primary contact recreation use. The combination of all the requirements at § 131.10 ensures that states and authorized tribes designate uses consistent with the goals of the Act unless the state or authorized tribe has demonstrated that such a use is not attainable. It also requires states and authorized tribes to maintain uses that have actually been attained.

C. Triennial Reviews

What does this rule provide and why?

The CWA and EPA's implementing regulation require states and authorized tribes to hold, at least once every three years, a public hearing for the purpose of reviewing applicable WQS (*i.e.* a triennial review). The CWA creates a partnership between states and authorized tribes, and EPA, by assigning states and authorized tribes the primary role of adopting WQS (CWA sections 101(b) and 303), and EPA the oversight role of reviewing and approving or disapproving state and authorized tribal WQS (CWA section 303(c)). Consistent with this partnership, the statute also assigns EPA the role of publishing national recommended criteria to assist states and authorized tribes in establishing water quality criteria in their WQS (CWA section 304(a)(1)). States and authorized tribes have several options for developing and adopting chemical, physical and biological criteria. They may use EPA's CWA section 304(a) criteria recommendations, modify EPA's CWA section 304(a) criteria recommendations to reflect site-specific conditions, or establish criteria using other scientifically defensible methods. Ultimately, states and authorized tribes must adopt criteria that are scientifically defensible and protective of the designated use to ensure that WQS continue to "protect the public health or welfare, enhance the quality of water and serve the purposes of" the Act (CWA section 303(c)(2)(A)).

In some cases, states and authorized tribes do not transparently communicate with the public their consideration of EPA's CWA section 304(a) criteria recommendations when deciding whether to revise their WQS. As a result, the public may be led to believe that states and authorized tribes are not considering some of the latest science that is reflected in EPA's new or updated CWA section 304(a) criteria recommendations. To ensure public transparency and clarify existing requirements, the final rule contains two revisions to the triennial review requirements at 40 CFR 131.20(a). First, the rule requires that if states and authorized tribes choose not to adopt new or revised criteria during their triennial review for any parameters for which EPA has published new or updated criteria recommendations under CWA section 304(a), they must explain their decision when reporting the results of their triennial review to EPA under CWA section 303(c)(1) and 40 CFR 131.20(c). Second, the rule clarifies the "applicable water quality standards" that states and authorized tribes must review triennially.

The first revision addresses the role of EPA's CWA section 304(a) criteria recommendations in triennial reviews. While states and authorized tribes are not required to adopt EPA's CWA section 304(a) criteria recommendations, they must consider them. EPA continues to invest significant resources to examine evolving science for the purpose of updating existing and developing new CWA section 304(a) criteria recommendations to help states and authorized tribes meet the requirements of the Act. Those recommendations are based on data and scientific judgments about pollutant concentrations and environmental or human health effects.[25]

EPA's proposed rule, requiring states and authorized tribes to "consider" EPA's new or updated CWA section 304(a) criteria recommendations, raised several commenter questions and concerns about how states and authorized tribes were to "document" such consideration.

Commenters also expressed concern that EPA was overstepping its authority by dictating how states and authorized tribes conduct their triennial reviews and by requiring states and authorized tribes to adopt EPA's CWA section 304(a) criteria recommendations. This rule focuses on how a state or authorized tribe explains its decisions to EPA (and the public) rather than on how the state or authorized tribe conducts its review. The CWA section 304(a) criteria are national recommendations, and states or authorized tribes may wish to consider site-specific physical and/or chemical water body characteristics and/or varying sensitivities of local aquatic communities. While states and authorized tribes are not required to adopt the CWA section 304(a) criteria recommendations, they are required under the Act and EPA's implementing regulations to adopt criteria that protect applicable designated uses and that are based on sound scientific rationale. Since EPA revises its CWA section 304(a) recommendations periodically to reflect the latest science, it is important that states and authorized tribes consider EPA's new or updated recommendations and explain any decisions on their part to not incorporate the latest science into their WQS.

An important component of triennial reviews is meaningful and transparent involvement of the public and intergovernmental coordination with local, state, federal, and tribal entities. Communication with EPA (and the public) about these decisions provides opportunities to assist states and authorized tribes in improving the scientific basis of its WQS and can build support for state and authorized tribal decisions. Such coordination ultimately increases the effectiveness of the state and authorized tribal water quality management processes. Following this rulemaking, when states and authorized tribes conduct their next triennial review they must provide an explanation for why they did not adopt new or revised criteria for parameters for which EPA has published new or updated CWA section 304(a) criteria recommendations since May 30, 2000.[26] During the triennial reviews that follow, states and authorized tribes must do the same for criteria related to parameters for which EPA has published CWA section 304(a) criteria recommendations since the states' or authorized tribes' most recent triennial review. This requirement applies regardless of whether new or updated CWA section 304(a) criteria recommendations are

[25] EPA's compilation of national water quality criteria recommendations, published pursuant to CWA section 304(a), can be found at: *http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.*

[26] WQS adopted and submitted to EPA by states and authorized tribes on or after May 30, 2000, must be approved by EPA before they become effective for CWA purposes, including the establishment of water quality-based effluent limits or development of total maximum daily loads (40 CFR 131.21, 65 FR 24641, April 27, 2000).

more stringent or less stringent than the state's or authorized tribe's applicable criteria because all stakeholders should know how the state or authorized tribe considered the CWA section 304(a) criteria recommendations when determining whether to revise their own WQS following a triennial review. A state's or authorized tribe's explanation may be situation-specific and could involve consideration of priorities and resources. EPA will not approve or disapprove this explanation pursuant to CWA section 303(c) nor will the explanation be used to disapprove new or revised WQS that otherwise meet the requirements of the CWA. Rather, it will inform both the public and EPA of the state's or authorized tribe's plans with respect to adopting new or revised criteria in light of the latest science. EPA strongly encourages states and authorized tribes to include their explanation on a publically accessible Web site or some other mechanism to inform the public of their decision.

The second revision addresses confusion expressed in public comments regarding the meaning of § 131.20(a) so that states, authorized tribes and the public are clear on the scope of WQS to be reviewed during a triennial review. By not addressing this issue directly in the proposal, EPA may have inadvertently created ambiguity by implying that the only criteria states and authorized tribes need to re-examine during a triennial review are those criteria related to the parameters for which EPA has published new or updated CWA section 304(a) criteria recommendations. However, EPA's intent was not to qualify the initial sentence in § 131.20(a) regarding "applicable water quality standards" (which are all WQS either approved or promulgated by EPA for a state or tribe) but to supplement it by adding more detail regarding the triennial review of any and all existing criteria established pursuant to 40 CFR 131.11. Thus, the final rule clarifies what the regulation means by "applicable water quality standards." [27]

When conducting triennial reviews, states and authorized tribes must review all applicable WQS adopted into state or tribal law pursuant to §§ 131.10–131.15 [28] and any federally promulgated WQS.[29] Applicable WQS specifically include designated uses (§ 131.10), water quality criteria (§ 131.11), antidegradation (§ 131.12), general policies (§ 131.13), WQS variances (§ 131.14), and provisions authorizing the use of schedules of compliance for WQBELs in NPDES permits (§ 131.15).[30] If, during a triennial review, the state or authorized tribe determines that the federally promulgated WQS no longer protect its waters, the state or authorized tribe should adopt new or revised WQS. If EPA approves such new or revised WQS, EPA would withdraw the federally promulgated WQS because they would no longer be necessary.

Some states and authorized tribes target specific WQS during an individual triennial review to balance resources and priorities. The final rule does not affect states' or authorized tribes' discretion to identify such priority areas for action. However, the CWA and EPA's implementing regulation require the state or authorized tribe to hold, at least once every three years, a public hearing [31] for the purpose of reviewing applicable WQS, not just a subset of WQS that the state or authorized tribe has identified as high priority. In this regard, states and authorized tribes must still, at a minimum, seek and consider public comment on all applicable WQS.

What did EPA consider?

EPA considered finalizing the revision to § 131.20(a) as proposed. However, given public commenters' confusion and concerns, as discussed previously, EPA ultimately rejected this option. EPA also considered foregoing revisions to § 131.20(a) altogether. However, this option would not ensure that states and authorized tribes adopt criteria that reflect the latest science, and thus EPA rejected it.

What is EPA's position on certain public comments?

One commenter requested a longer period than three years for states and authorized tribes to consider new or updated CWA section 304(a) criteria recommendations because it was neither reasonable nor feasible to conduct a comprehensive review and rulemaking in this timeframe, including the public participation component. Other commenters suggested that EPA allow triennial reviews to occur "periodically," while some suggested that nine or 12 years would be a more appropriate frequency of review.

Although EPA acknowledges the challenges (*e.g.*, the legal and administrative processes, resource constraints) that states and authorized tribes may experience when conducting triennial reviews, the three-year timeframe for triennial review comes directly from CWA section 303(c)(1). EPA has no authority to provide a longer timeframe for triennial reviews.

D. Antidegradation

One of the principal objectives of the CWA is to "*maintain* the chemical, physical and biological integrity of the Nation's waters." [32] Congress expressly affirmed this principle of "antidegradation" in the Water Quality Act of 1987 in CWA sections 101(a) and 303(d)(4)(B). EPA's WQS regulation has included antidegradation provisions since 1983. In particular, 40 CFR 131.12(a)(2) includes a provision that protects "high quality" waters (*i.e.*, those with water quality that is better than necessary to support the uses specified in section 101(a)(2) of the Act.)

Maintaining high water quality is critical to supporting economic and community growth and sustainability. Protecting high water quality also provides a margin of safety that will afford the water body increased resilience to potential future stressors, including climate change. Degradation of water quality can result in increased public health risks, higher treatment costs that must be borne by ratepayers and local governments, and diminished aquatic communities, ecological diversity, and ecosystem services. Conversely, maintaining high water quality can lower drinking water costs, provide revenue for tourism and recreation, support commercial and recreational fisheries, increase property values, create jobs and sustain local communities.[33] While preventing degradation and maintaining a reliable source of clean water involves costs, it can be more effective and efficient than

[27] EPA published the *What is a New or Revised Water Quality Standard Under CWA 303(c)(3) Frequently Asked Questions* (EPA–820–F–12–017, October 2012) to consolidate EPA's interpretation (informed by the CWA, EPA's implementing regulation at 40 CFR part 131, and relevant case law) of what constitutes a new or revised WQS that the Agency has the CWA section 303(c)(3) authority and duty to approve or disapprove (*http://water.epa.gov/scitech/swguidance/standards/upload/cwa303faq.pdf*).

[28] Definitions adopted by states and authorized tribes are considered WQS when they are inextricably linked to provisions adopted pursuant to §§ 131.10–131.15.

[29] Any WQS that EPA has promulgated for a state or tribe are found in 40 CFR part 131, subpart D. See also: *http://water.epa.gov/scitech/swguidance/standards/wqsregs.cfm#proposed.*

[30] This rule finalizes § 131.14 (WQS Variances) and § 131.15 (Provisions Authorizing the Use of Schedules of Compliance for WQBELs in NPDES permits). For detailed discussion about these sections, see sections II.E and II.F of this document, respectively.

[31] For detailed discussion about this final rule for § 131.20(b), related to public participation, see section II.G of this document.

[32] See CWA section 101(a) (emphasis added).

[33] *http://water.epa.gov/polwaste/nps/watershed/upload/economic_benefits_factsheet3.pdf; Economic Benefits of Protecting Healthy Watersheds* (EPA 841–N–12–004, April 2012).

investing in long-term restoration efforts or remedial actions.

This rule revises the antidegradation regulation to enhance protection of high quality waters and to promote consistency in implementation. The new provisions require states and authorized tribes to follow a more structured process when making decisions about preserving high water quality. They also increase transparency and opportunities for public involvement, while preserving states' and authorized tribes' decision-making flexibility. The revisions meet the objectives of EPA's proposal, although EPA made some changes to the regulatory language after further consideration of the Agency's policy objectives and in response to public comments.

This rule establishes requirements in the following areas: Identification of high quality waters, analysis of alternatives, and antidegradation implementation methods. In addition to the substantive changes described in the following section, this rule also includes editorial changes that are not substantive in nature. For a detailed discussion of EPA's CWA authority regarding antidegradation, see the preamble to the proposed rule at 78 FR 54526 (September 4, 2013).

Identification of Waters for High Quality Water (Tier 2) Protection

What does this rule provide and why?

Tier 2 refers to a decision-making process by which a state or authorized tribe decides how and how much to protect water quality that exceeds levels necessary to support the uses specified in Section 101(a)(2) of the Act. The final rule at § 131.12(a)(2)(i) provides that states and authorized tribes may identify waters for Tier 2 protection on either a parameter-by-parameter or a water body-by-water body basis. The rule also specifies that, where states and authorized tribes identify waters on a water body-by-water body basis, states and authorized tribes must involve the public in any decisions pertaining to when they will provide Tier 2 protection, and the factors considered in such decisions. Further, states and authorized tribes must not exclude water bodies from Tier 2 protection solely because water quality does not exceed levels necessary to support all of the uses specified in CWA section 101(a)(2). This rule requires that states' and authorized tribes' antidegradation policies be consistent with these new requirements.

States and authorized tribes typically use one of two approaches to identify high quality waters consistent with the CWA. States and authorized tribes using a parameter-by-parameter approach generally identify high quality waters at the time an entity proposes the activity that would lower water quality. Under this approach, states and authorized tribes identify parameters for which water quality is better than necessary to support the uses specified in CWA section 101(a)(2) and provide Tier 2 protection for any such parameters. Alternatively, states and authorized tribes using a water body-by-water body approach generally identify waters that will receive Tier 2 protection by weighing a variety of factors, in advance of any proposed activity. States and authorized tribes can identify some waters using a parameter-by-parameter approach and other waters using a water body-by-water body approach.

The 1983 WQS regulation did not specify which approach states and authorized tribes must use to identify waters for Tier 2 protection. In the 1998 ANPRM, EPA articulated that either approach, when properly implemented, is consistent with the CWA, and described advantages and disadvantages to both approaches. A parameter-by-parameter approach can be easier to implement, can be less susceptible to challenge, and can result in more waters receiving some degree of Tier 2 protection. The ANPRM also articulated: "[t]he water body-by-water body approach, on the other hand, allows for a weighted assessment of chemical, physical, biological, and other information (*e.g.*, unique ecological or scenic attributes). In this regard, the water body-by-water body approach may be better suited to EPA's stated vision for the [WQS] program . . . This approach also allows for the high quality water decision to be made in advance of the antidegradation review . . ., which may facilitate implementation. A water body-by-water body approach also allows [s]tates and [t]ribes to focus limited resources on protecting higher-value [s]tate or [t]ribal waters. The water body-by-water body approach can . . . preserve high quality waters on the basis of physical and biological attributes, rather than high water quality attributes alone."

Because the original WQS regulation did not provide specific requirements regarding use of the water body-by-water body approach, it was possible for states and authorized tribes to identify high quality waters in a manner inconsistent with the CWA and the intent of EPA's implementing regulation. In some cases, states and authorized tribes have used the water body-by-water body approach without documenting the factors that inform the decision or informing the public. For example, some states or authorized tribes have excluded waters from Tier 2 protection entirely based on the fact that the water was included on a CWA section 303(d) list for a single parameter without allowing an opportunity for the public to provide input.

This rule reaffirms EPA's support for both approaches. The new regulatory requirements included at § 131.12(a)(2)(i) only apply to the water body-by-water body approach because they are unnecessary for the parameter-by-parameter approach. States and authorized tribes using the parameter-by-parameter approach provide Tier 2 protection to all chemical, physical, and biological parameters for which water quality is better than necessary to protect the uses specified in CWA section 101(a)(2). Because the identification of waters that are high quality with respect to relevant parameters would occur in the context of allowing a specific activity, the level of protection is already subject to any public involvement required for that activity. For example, an NPDES permit writer calculating WQBELs would use available data and information about the water body to determine whether assimilative capacity exists for the relevant parameters. The state or authorized tribe would then provide Tier 2 protection for all parameters for which assimilative capacity exists. The draft permit would reflect the results of the Tier 2 review, hence providing an opportunity for public involvement.

The requirement at § 131.12(a)(2)(i) regarding public involvement increases the transparency of and accountability for states' and authorized tribes' water quality management decisions. The final rule is consistent with the CWA and the WQS regulation's emphasis on the public's role in water quality protection. A key part of a state's or authorized tribe's antidegradation process involves decisions on how to manage high water quality, a shared public resource. Commenters expressed concern that the proposed rule did not require states and authorized tribes to engage the public on decisions when implementing a water body-by-water body approach. Consequently, the public would not know the factors a state or authorized tribe considered in deciding that the water body did not merit Tier 2 protection, which would limit the public's ability to provide constructive input during the permit's public notice and comment period.

To provide for well-informed public input and to aid states and authorized tribes in making robust decisions, EPA recommends states and authorized tribes document their evaluation of the Tier 2 decision, including the factors considered and how those factors were weighed. The case of *Ohio Valley Envtl. Coalition* v. *Horinko* demonstrates why it is important for states and authorized tribes to articulate the rationale for their decisions.[34] In this case, the U.S. District Court for the Southern District of West Virginia considered whether the record contained sufficient evidence to justify EPA's approval of the state's exclusion of particular water bodies from Tier 2 protection. The state had classified some CWA section 303(d) listed waters as waters to receive Tier 2 protection, while it had excluded other similar waters with similar impairments from Tier 2 protection. The Court found the administrative record insufficient to support EPA's decision to approve the state's classification because the state's CWA section 303(d) listing was the only evidence related to the water quality of those river segments. The Court did not opine on whether, in a different factual situation, categorically excluding waters from Tier 2 protection based on CWA section 303(d) impairments would be consistent with the CWA.

To minimize the administrative processes associated with this rule, EPA uses the phrase "opportunity for public involvement" rather than "public participation." "Public participation" at 40 CFR 131.20(b)[35] refers to a state or authorized tribe holding a public hearing for the purpose of reviewing WQS. With this rule, EPA provides states and authorized tribes the flexibility to engage the public in a way that suits the state or authorized tribe and the public. For example, a state or authorized tribe could develop lists of waters that will and will not receive Tier 2 protection along with descriptions of the factors considered in making each of those decisions and post that information on its Web site. To obtain public input, the state or authorized tribe could share these lists during a triennial review and/or during revision of antidegradation implementation methods. Such an approach has the advantage of streamlining both the decision-making and public involvement processes. As another example, a state could use the NPDES process to engage the public at the time it drafts a permit that would allow a lowering of water quality. The state would document the relevant information related to its decision in the permit fact sheet provided to the public and specifically request comment on its Tier 2 protection decision.

States and authorized tribes can provide additional avenues for public involvement by providing structured opportunities for the public to initiate antidegradation discussions. For example, a state or authorized tribe could provide a petition process in which citizens request Tier 2 protection for specific waters, and those citizens could provide data and information for a state's or authorized tribe's consideration. Also, states and authorized tribes can establish a process to facilitate public involvement in identifying waters as Outstanding National Resource Waters (ONRWs).

An additional requirement at § 131.12(a)(2)(i) provides that states and authorized tribes must not exclude a water body from the protections in § 131.12(a)(2) solely because water quality does not exceed levels necessary to support all of the uses specified in CWA section 101(a)(2). For a discussion on why such an approach is inconsistent with the Act, see the preamble to the proposed rule at 78 FR 54527 (September 4, 2013). Thus, when considering whether to exclude waters from Tier 2 protection, states and authorized tribes must consider the overall quality of the water rather than whether water quality is better than necessary for individual chemical, physical, and biological parameters to support all the uses specified in CWA section 101(a)(2). The rule provides for a decision-making process where states and authorized tribes consider water quality and reasons to protect water quality more broadly. This can lead to more robust evaluations of the water body, and potentially more waters receiving Tier 2 protection. To make a decision to exclude a water body from Tier 2 protection, states and authorized tribes must identify the factors considered which should include factors that are rooted in the goals of the CWA, including the chemical, physical, and biological characteristics of a water body. Where states and authorized tribes wish to consider CWA section 303(d) listed impairments, it would be important that they also consider all other relevant available data and conduct an overall assessment of a water's characteristics. It would also be important that states and authorized tribes consider the public value of the water. This includes the water's impact on public health and welfare, the existing aquatic and recreational uses, and the value of retaining ecosystem resilience against the effects of future stressors, including climate change. For additional information on this overall assessment, see the preamble to the proposed rule at 78 FR 54527 (September 4, 2013).

This requirement is consistent with the proposed rule. However, to accurately articulate the requirement, and to remain consistent with § 131.12(a)(2), the final rule text reflects that for a water to have available assimilative capacity for which to provide Tier 2 protection, the water quality must "exceed" the levels necessary (*i.e.*, be better than necessary) to support the uses specified in CWA section 101(a)(2). Commenters stated that some members of the public could misinterpret the phrase "high quality waters" in the proposal to include waters that *meet* but do not *exceed* the water quality necessary to support the uses specified in CWA section 101(a)(2). The final rule replaces "high quality waters" with the phrase "waters for the protections described in (a)(2) of this section." The final rule also says waters cannot be excluded from Tier 2 protection solely "because water quality does not exceed levels necessary to support all of the uses specified in section 101(a)(2) of the Act" instead of "because not all of the uses specified in CWA section 101(a)(2) are attained," as stated in the proposal.

Where water quality is better than necessary to support all of the uses specified in CWA section 101(a)(2), § 131.12(a)(2) requires states and authorized tribes to provide Tier 2 protection. Where water quality is not better than necessary to support all of the uses specified in CWA section 101(a)(2), the final rule does not require states and authorized tribes to provide Tier 2 protection for the water body. However, in instances where states and authorized tribes lack data and information on the water quality to make individual water body conclusions, EPA recommends that they provide all or a subset of their waters with Tier 2 protection, by default. Doing so will increase the probability that these waters will maintain a level of resiliency to future stressors.

This rule requires states' and authorized tribes' antidegradation policies (which are legally binding state and authorized tribal provisions subject to public participation) to be consistent with the new requirements related to identifying waters for Tier 2 protection. Since states and authorized tribes must provide for public participation on their antidegradation policies, placing their requirements for identification of high quality waters in their antidegradation policies increases accountability and transparency. The proposed rule

[34] *Ohio Valley Envtl. Coal.* v. *Horinko*, 279 F. Supp. 2d 732, 746–50 (S.D. W. Va. 2003).

[35] See section II.G for more information on the final rule change related to public participation.

articulated that states and authorized tribes must design their implementation methods to achieve the requirements for identifying high quality waters. Commenters questioned whether the proposed requirement for identifying high quality waters was mandatory, since the proposal did not require states and authorized tribes to adopt the requirement into their legally binding policies. Some commenters suggested requiring states and authorized tribes to adopt all implementation methods into binding provisions. While some states and authorized tribes find adoption of their implementation methods to be helpful, others view it as burdensome. EPA determined that while adopting implementation methods increases accountability and transparency, states and authorized tribes could still provide this accountability and transparency for identification of waters for Tier 2 protection without a requirement to adopt implementation methods. Therefore, the final rule requires antidegradation policies to be consistent with the provision at § 131.12(a)(2)(i). States and authorized tribes have the discretion and flexibility to adopt antidegradation provisions that address other aspects of antidegradation that are not specifically addressed in § 131.12(a). Where a state or authorized tribe chooses to include antidegradation implementation methods in non-binding guidance, the methods must be consistent with the applicable state or authorized tribal antidegradation requirements that EPA has approved. Consistent with § 122.44(d)(1)(vii)(a), permits must derive from and comply with all applicable WQS. Otherwise, EPA could have a basis to object to the permits.

What did EPA consider?

EPA considered not revising § 131.12(a)(2) and continuing to provide no new regulatory requirements for identification of waters for Tier 2 protection. EPA also considered prohibiting the water body-by-water body approach. Providing no regulatory requirements would continue to allow states and authorized tribes to implement a water body-by-water body approach that is potentially inconsistent with the CWA, while prohibiting the water body-by-water body approach would limit states' and authorized tribes' flexibility to prioritize their waters for Tier 2 protection. EPA rejected these options in favor of a more balanced approach by placing conditions on how states and authorized tribes use their discretion to better ensure protection of high quality waters.

EPA considered finalizing the rule as proposed, without a requirement for public involvement in decisions about whether to provide Tier 2 protection to a water body; however, EPA found that public involvement is critical for increasing accountability and transparency and included the requirement in the final rule. EPA also considered providing for an EPA approval or disapproval action under CWA section 303(c) of states' and authorized tribes' decisions on whether to provide Tier 2 protection to each water. EPA ultimately decided not to include such a requirement because of concern that it would add more administrative and rulemaking burden for states and authorized tribes than EPA determined was necessary to ensure public involvement. EPA considered specifying precisely which waters must receive Tier 2 protection. However, EPA did not include such specificity in the rule because there are multiple ways that states and authorized tribes can make well-reasoned decisions on Tier 2 protection based on case-specific facts.

Analysis of Alternatives

What does this rule provide and why?

The final rule at § 131.12(a)(2)(ii) provides that before allowing a lowering of high water quality, states and authorized tribes must find, after an analysis of alternatives, that such a lowering is necessary to accommodate important economic or social development in the area in which the waters are located. That analysis must evaluate a range of non-degrading and less degrading practicable alternatives. For the purposes of this requirement, the final rule at § 131.3(n) defines "practicable" to mean "technologically possible, able to be put into practice, and economically viable." When an analysis identifies one or more such practicable alternatives, states and authorized tribes may only find that a lowering is necessary if one such alternative is selected for implementation. This rule requires that states' and authorized tribes' antidegradation policies must be consistent with these new requirements.

Section 131.12(a)(2)(ii) requires a structured analysis of alternatives, which will increase transparency and consistency in states' and authorized tribes' decisions about high water quality. The new requirement makes the analysis of alternatives an integral part of a state's or authorized tribe's finding that degradation of high quality water is "necessary." Such an analysis provides states and authorized tribes with a basis to make informed and reasoned decisions, assuring that degradation only occurs where truly necessary. This rule refers to "analysis of alternatives" rather than "alternatives analysis" as in the proposal. This makes clear that the analysis required in § 131.12(a)(2)(ii) is distinct from the "alternatives analysis" required in other programs, such as the National Environmental Policy Act and CWA section 404 permitting.

Section 131.12(a)(2)(ii) is consistent with the proposed rule, but makes clear that states' and authorized tribes' findings that a lowering is necessary depends on both an analysis of alternatives and an analysis related to economic or social development. Commenters were concerned that the proposed rule seemed to remove the requirement at § 131.12(a)(2) for states and authorized tribes to consider whether a lowering of water quality will "accommodate important economic or social development in the area in which the waters are located."

This rule preserves states' and authorized tribes' discretion to decide the order in which they satisfy these requirements. A state or authorized tribe can choose to first review an analysis of economic or social development. If it finds that the proposed lowering of water quality would accommodate important economic or social development, it can then require an analysis of alternatives to see if the lowering could be prevented or lessened. If, on the other hand, a state or authorized tribe finds that the proposed lowering of water quality would not accommodate important economic or social development, it could choose to disallow lowering of water quality and terminate the Tier 2 review without ever requiring an analysis of alternatives. Similarly, a state or authorized tribe could first choose to require an analysis of alternatives and then examine an analysis of economic or social development. In this case, if a non-degrading alternative is selected for implementation, the state or authorized tribe does not need to proceed with an analysis of economic or social development.

Although states and authorized tribes are responsible for making a finding to allow a lowering of water quality based on a reasonable, credible, and adequate analysis of alternatives, states and authorized tribes themselves need not conduct the analysis of alternatives or select the alternative to be implemented. Commenters expressed concern that the proposed rule language implied that states and authorized tribes must perform the analysis themselves, when other entities may be best positioned to analyze the alternatives. The final rule language allows states and authorized tribes to rely on analyses prepared by third parties (*e.g.,* a permit applicant). This preserves appropriate flexibility for states' and authorized tribes' decision-makers, and can bring additional resources and expertise to the analysis. States and authorized tribes remain ultimately responsible for making findings to allow degradation and for basing their decisions on adequate analyses. If the state or authorized tribe deems an initial analysis of alternatives insufficient to support a finding that a lowering of high water quality is "necessary," it can request additional analyses of alternatives from the permit applicant or other entities. A state or authorized tribe can also obtain information on common practicable alternatives appropriate for a proposed activity from additional existing resources.[36]

The final rule specifies that states and authorized tribes must analyze "practicable alternatives that would prevent or lessen the degradation," rather than "non-degrading and minimally degrading practicable alternatives that have the potential to prevent or minimize the degradation," as proposed. While non-degrading or minimally degrading alternatives preserve high water quality to a greater extent, in cases where no minimally-degrading alternatives exist, a less degrading alternative will still provide a margin of protection for the high quality water. The final rule requires a broader, more complete analysis.

To enhance clarity and provide for consistency in implementation, this rule finalizes a definition of the word "practicable." The definition embodies a common sense notion of practicability—*i.e.,* an alternative that can actually be implemented under the circumstances. Because "practicable" appears in other contexts related to water quality, the definition at § 131.3(n) is only applicable for § 131.12(a)(2)(ii). This definition is consistent with the one articulated in the preamble to the proposed rule,[37] but eliminates redundancy and omits "at the site in question" in response to commenters' concern that relocation of a proposed activity may be a less degrading alternative that the state or authorized tribe can consider.

[36] E.g., EPA's Municipal Technologies Web site, which presents technology fact sheets to assist in the evaluation of different technologies for wastewater (*http://water.epa.gov/scitech/wastetech/mtb_index.cfm*).

[37] See 78 FR 54528 (September 4, 2013).

Section 131.12(a)(2)(ii) provides for preservation of high water quality by requiring a less degrading practicable alternative to be selected for implementation, if available, before states and authorized tribes may find that a lowering of water quality is necessary. This requirement applies even if the analysis identifies only one alternative. States and authorized tribes must still make a finding that a lowering is necessary if the analysis does not identify any practicable alternatives that lessen degradation. On the other hand, if the analysis results in choosing an alternative that avoids degradation, a state or authorized tribe need not make a finding. Regardless of the number of alternatives identified, the analysis should document a level of detail that reflects the significance and magnitude of the particular circumstances encountered, to provide the public with the necessary information to understand how the state or authorized tribe made its decision.

EPA chose not to require implementation of the least degrading practicable alternative to allow states and authorized tribes the flexibility to balance multiple considerations. Some alternatives to lowering water quality can have negative environmental impacts in other media (*e.g.,* air, land). For example, incinerating pollutants rather than discharging the pollutants to surface waters could adversely impact air quality and energy use, and land application of pollutants could have adverse terrestrial impacts. EPA recommends that states and authorized tribes consider cross-media impacts and, where possible, seek alternatives that minimize degradation of water quality and also minimize other environmental impacts.

The final rule requires states' and authorized tribes' antidegradation policies (which are legally binding provisions subject to public participation) to be consistent with the new requirements related to analysis of alternatives. As with the provision on identification of waters for Tier 2 protection at § 131.12(a)(2)(i), EPA determined that antidegradation policies must be consistent with the federal regulation on analysis of alternatives at § 131.12(a)(2)(ii) to increase accountability and transparency.

What did EPA consider?

EPA considered finalizing the proposed rule without alteration. EPA did not choose this option in light of commenters' suggestions to clarify the language in order to avoid confusion as to who is responsible for conducting the analysis. EPA also rejected an option to forego any revisions related to an analysis of alternatives, as this would not provide clarification regarding what type of analysis supports states' or authorized tribes' decisions that a lowering of water quality is "necessary," thus risking a greater loss of water quality.

Antidegradation Implementation Methods

What does this rule provide and why?

The rule at § 131.12(b) requires states' and authorized tribes' antidegradation implementation methods (whether or not those methods are adopted into rule) to be consistent with their antidegradation policies and with § 131.12(a). This rule also requires states and authorized tribes to provide an opportunity for public involvement during the development and any subsequent revisions of antidegradation implementation methods, and to make the methods available to the public.

Finally, this rule adds § 131.5(a)(3) to explicitly specify that EPA has the authority to determine whether the states' and authorized tribes' antidegradation policies and any adopted antidegradation implementation methods[38] are consistent with the federal antidegradation requirements at § 131.12. This revision does not expand EPA's existing CWA authority, rather it ensures § 131.5 is consistent with §§ 131.6 and 131.12.

The public involvement requirement at § 131.12(b) increases transparency, accountability, and consistency in states' and authorized tribes' implementation. EPA proposed a requirement that implementation methods be publicly available. As EPA discussed in the preamble to the proposed rule, CWA section 101(e) provides that "public participation in the development, revision, and enforcement of any regulations, standard, effluent limitation, plan, or program established . . . under this Act shall be provided for, encouraged, and assisted . . ." Thus, this rule also provides for public involvement during development or revision of implementation methods. A state or authorized tribe may decide to offer more than one opportunity to most effectively engage the public. States and authorized tribes can use various mechanisms to provide such

[38] See *http://water.epa.gov/scitech/swguidance/standards/cwa303faq.cfm. What is a New or Revised Water Quality Standard Under CWA 303(c)(3) Frequently Asked Questions* (EPA–820–F–12–017, October 2012).

opportunities, including a public hearing, a public meeting, a public workshop, and different ways of engaging the public via the Internet, such as webinars and Web site postings. If a state or authorized tribe adopts antidegradation implementation methods as part of its WQS or other legally binding provisions, the state's or authorized tribe's own public participation requirements and 40 CFR part 25 and § 131.20(b) of the federal regulation, will satisfy this requirement.

Section 131.5(a)(3) makes explicit EPA's authority to review states' and authorized tribes' antidegradation policies and any adopted antidegradation implementation methods and to determine whether those policies and methods are consistent with § 131.12. EPA recommends states and authorized tribes adopt binding implementation methods to provide more transparency and consistency for the public and other stakeholders and to increase accountability. States and authorized tribes may find that the Continuing Planning Process provisions described at CWA section 303(e) and § 130.5 can facilitate the state's or authorized tribe's establishment and maintenance of a process for WQS implementation consistent with the requirements of the final rule.

Here, EPA clarifies the terms "antidegradation policy" and "antidegradation implementation methods." For the purposes of § 131.12, states' and authorized tribes' "antidegradation policies" must be adopted in rule or other legally binding form, and must be consistent with the requirements of § 131.12(a). EPA originally promulgated this requirement in 1983. "Antidegradation implementation methods" refer to any additional documents and/or provisions in which a state or authorized tribe describes methods for implementing its antidegradation policy, whether or not the state or authorized tribe formally adopts the methods in regulation or other legally binding form. If a state or authorized tribe does not choose to adopt the entirety of its implementation methods, EPA recommends, at a minimum, adopting in regulation or other legally binding form any antidegradation program elements that substantively express the desired instream level of protection and how that level of protection will be expressed or established for such waters in the future.

What did EPA consider?

EPA considered not adding § 131.5(a)(3). EPA rejected this option in light of commenters' suggestions to clarify the extent of EPA's authority. EPA also considered not adding § 131.12(b) or establishing § 131.12(b), as proposed. However, public involvement in the development and implementation of states' and authorized tribes' antidegradation implementation methods is fundamental to meeting the CWA requirements to restore and maintain water quality. EPA considered revising the rule to require that all states and authorized tribes adopt the entirety of their antidegradation implementation methods in regulation to improve accountability and transparency, as some commenters suggested. EPA did not make this change because it would limit states' and authorized tribes' ability to easily revise their implementation methods in order to adapt and improve antidegradation protection in a timely manner. Some states and authorized tribes have difficulty adopting their methods because of resource constraints, state or tribal laws, or complex rulemaking processes. Instead of requiring adoption of implementation methods, the final rule achieves more accountability by establishing specific requirements for states' and authorized tribes' antidegradation policies regarding two key aspects of Tier 2 implementation.

What is EPA's position on certain public comments?

Commenters requested clarification concerning whether states and authorized tribes must change their approaches to antidegradation to be consistent with the final rule. Where a state or authorized tribe already has established antidegradation requirements consistent with this rule, EPA does not anticipate the need for further changes.

Many commenters requested clarification concerning whether the proposed rule affects states' and authorized tribes' ability to use *de minimis* exclusions. Some states and authorized tribes use *de minimis* exclusions to prioritize and manage limited resources by excluding activities from Tier 2 review if they view the activity as potentially causing an insignificant lowering of water quality. This allows states and authorized tribes to use their limited resources where it can have the greatest environmental impact. Although EPA did not propose any revisions related to defining or authorizing *de minimis* exclusions, some commenters requested that EPA finalize a rule that explicitly accepts them, and others asked EPA to prohibit them. Section 131.12—including the revisions in this rule—does not address *de minimis* exclusions. States and authorized tribes can use *de minimis* exclusions, as long as they use them in a manner consistent with the CWA and § 131.12.

The DC Circuit explained in *Ala. Power* v. *Costle* that under the *de minimis* doctrine, "[c]ategorical exemptions may also be permissible as an exercise of agency power, inherent in most statutory schemes, to overlook circumstances that in context may fairly be considered *de minimis*."[39] The Court went on to explain that the authority to create a *de minimis* provision "is not an ability to depart from the statute, but rather a tool to be used in implementing the legislative design."[40] The Sixth Circuit has also explained that *de minimis* provisions are created through an "administrative law principle which allows an agency to create unwritten exceptions to a statute or rule for insignificant or '*de minimis*' matters."[41]

States and authorized tribes have historically defined "significant degradation" in a variety of ways. Significance tests range from simple to complex, involve qualitative or quantitative measures or both, and may vary depending upon the type of pollution or pollutant (*e.g.*, the approach may be different for highly toxic or bioaccumulative pollutants). EPA does not endorse one specific approach to identifying what constitutes insignificant degradation, though EPA does recognize that one potential way a state or authorized tribe could describe its *de minimis* methodology would be to identify a "significance threshold" as percentage of assimilative capacity loss for a parameter or lowering of water quality that would be considered "insignificant." EPA has not found a scientific basis to identify a specific percentage of loss of assimilative capacity or lowering of water quality that could reasonably be considered insignificant for all parameters, in all waters, at all times, for all activities. Depending on the water body's chemical, physical, and biological characteristics and the circumstances of the lowering of water quality, even very small changes in water quality could cause significant effects to the water body.

Courts have explained that the implied *de minimis* provision authority is "narrow in reach and tightly bounded by the need to show that the situation

[39] *Ala. Power.* v. *Costle*, 636 F.2d. 323, 360 (D.C. Cir. 1979).

[40] *Id.*

[41] *Ky. Waterways Alliance* v. *Johnson*, 540 F.3d 466, 483 (6th Cir. 2008).

is genuinely *de minimis* or one of administrative necessity."[42] Accordingly, this authority only applies "when the burdens of regulation yield a gain of trivial or no value."[43] Finally, a "determination of when matters are truly *de minimis* naturally will turn on the assessment of particular circumstances, and the agency will bear the burden of making the required showing."[44]

Unless a state or authorized tribe can provide appropriate technical justification, it should not create categorical exemptions from Tier 2 review for specific types of activities based on a general finding that such activities do not result in significant degradation. States and authorized tribes should also consider the appropriateness of exemptions depending on the types of chemical, physical, and biological parameters that would be affected. For example, if a potential lowering of water quality contains bioaccumulative chemicals of concern, a state or authorized tribe should not apply a categorical *de minimis* exclusion because even extremely small additions of such chemicals could have a significant effect. For such pollutants, it could be possible to apply a *de minimis* exclusion on a case by case basis, but the state or authorized tribe should carefully consider any such proposed lowering prior to determining that it would be insignificant. States and authorized tribes should also consider the potential effects of cumulative impacts on the same water body to ensure that the cumulative degradation from multiple activities each considered to have a *de minimis* impact will not cumulatively add up to a significant impact. Finally, if a state or authorized tribe intends to use *de minimis* exclusions, then EPA recommends that it describe how it will use *de minimis* in its antidegradation implementation methods. This guarantees that states and authorized tribes will inform the public ahead of time about how they will use *de minimis* exemptions.

EPA also encourages states and authorized tribes to consider other ways to help focus limited resources where they may result in the greatest environmental protection. A state or authorized tribe should consider whether it will require more effort and resources to justify a *de minimis* exemption than it would take to actually complete a Tier 2 review for the activity. EPA encourages states and authorized tribes to develop ways to streamline Tier 2 reviews, rather than seeking to exempt activities from review entirely.

E. WQS Variances

What does this rule provide and why?

This rule establishes an explicit regulatory framework for the adoption of WQS variances that states and authorized tribes can use to implement adaptive management approaches to improve water quality. States and authorized tribes can face substantial uncertainty as to what designated use may ultimately be attainable in their waters. Pollutants that impact such waters can result from large-scale land use changes, extreme weather events, or environmental stressors related to climate change that can hinder restoration and maintenance of water quality. In addition, pollutants can be persistent in the environment and, in some cases, lack economically feasible control options. WQS variances are customized WQS that identify the highest attainable condition applicable throughout the WQS variance term. For a discussion of why it is important for states and authorized tribes to include the highest attainable condition, see the preamble to the proposed rule at 78 FR 54534 (September 4, 2013). States and authorized tribes could use one or more WQS variances to require incremental improvements in water quality leading to eventual attainment of the ultimate designated use.

While EPA has long recognized WQS variances as an available tool, the final rule provides regulatory certainty to states and authorized tribes, the regulated community, and the public that WQS variances are a legal WQS tool. The final rule explicitly authorizes the use of WQS variances and provides requirements to ensure that WQS variances are used appropriately. Such a mechanism allows states and authorized tribes to work with stakeholders and assure the public that WQS variances facilitate progress toward attaining designated uses. When all parties are engaged in a transparent process that is guided by an accountable framework, states and authorized tribes can move past traditional barriers and begin efforts to maintain and restore waters. As discussed in the preamble to the proposed rule at 78 FR 54531 (September 4, 2013), a number of states have not pursued WQS variances. For WQS variances submitted to EPA between 2004 and 2015, 75% came from states covered by the "Water Quality Guidance for the Great Lakes System" rulemaking at 40 CFR part 132. EPA attributes the Region 5 states' success in adopting and submitting WQS variances to the fact that the states and their stakeholders have had more specificity in regulation regarding WQS variances than the rest of the country. This final rule is intended to provide the same level of specificity nationally.

EPA's authority to establish requirements for WQS variances comes from CWA sections 101(a) and 303(c)(2). This rule reflects this authority by explicitly recognizing that states and authorized tribes may adopt time-limited WQS with a designated use and criterion reflecting the highest attainable condition applicable throughout the term of the WQS variance, instead of pursing a permanent[45] revision of the designated use and associated criteria. WQS variances serve the national goal in section 101(a)(2) of the Act and the ultimate objective of the CWA to restore and maintain the chemical, physical, and biological integrity of the Nation's waters because WQS variances are narrow in scope and duration and are designed to make progress toward water quality goals. When a WQS variance is in place, all other applicable standards not addressed in the WQS variance continue to apply, in addition to the ultimate water quality objectives (*i.e.*, the underlying WQS). Also, by requiring the highest attainable condition to be identified and applicable throughout the term of the WQS variance, the final rule provides a mechanism to make incremental progress toward the ultimate water quality objective for the water body and toward the restoration and maintenance of the chemical, physical, and biological integrity of the Nation's waters.

This rule adds a new regulatory section at § 131.14 that explicitly authorizes the use of WQS variances when the applicable designated uses are not attainable in the near-term but may be attainable in the future. The rule clarifies how WQS variances relate to other CWA programs and specifies the information that the state and authorized tribe must adopt in any WQS variance, including the highest attainable condition. States and authorized tribes must submit to EPA supporting documentation that demonstrates why the WQS variance is

[42] *Id.* (quoting *Ala. Power.* v. *Costle*, 636 F.2d. 323, 361 (D.C. Cir. 1979)).

[43] *Id.* (quoting *Greenbaum* v. *U.S. Envtl Prot. Agency*, 370 F.3d 527, 534 (6th Cir. 2004)).

[44] *Id.* (quoting *Greenbaum* v. *U.S. Envtl Prot. Agency*, 370 F.3d 527, 534 (6th Cir. 2004)).

[45] "Permanent" is used here to contrast between the time-limited nature of WQS variances and designated use changes. In accordance with 40 CFR 131.20, waters that "do not include the uses specified in section 101(a)(2) of the Act shall be re-examined every 3 years to determine if new information has become available. If such new information indicates that the uses specified in section 101(a)(2) of the Act are attainable, the [s]tate shall revise its standards accordingly."

needed and justifies the term and interim requirements. Finally, the rule requires states and authorized tribes to reevaluate WQS variances longer than five years on an established schedule with public involvement. The changes from the proposed rule respond to public comments and remain consistent with the Agency's clearly articulated policy objectives in the proposed rule. This rule also includes editorial changes that are not substantive in nature.

First, to provide clarity, this rule includes a new section at § 131.14 to explicitly authorize states and authorized tribes to adopt WQS variances. States and authorized tribes may adopt WQS variances for a single discharger, multiple dischargers, or a water body or waterbody segment, but it only applies to the permittee(s) or water body/waterbody segment(s) specified in the WQS variance. The rule defines a WQS variance at § 131.3(o) as a time-limited designated use and criterion for a specified pollutant(s), permittee(s), and/or water body or waterbody segment(s) that reflects the highest attainable condition applicable throughout the specified time period. The rule further specifies that a WQS variance is a new or revised WQS subject to EPA review and approval or disapproval,[46] requires a public process, and must be reviewed on a triennial basis. All other applicable standards not specifically addressed by the WQS variance remain applicable. This rule adds § 131.5(a)(4) to explicitly specify that EPA has the authority to determine whether any WQS variances adopted by a state or authorized tribe are consistent with the requirements at § 131.14. A WQS variance shall not be adopted if the designated use and criterion can be achieved by implementing technology-based effluent limits required under sections 301(b) and 306 of the Act.

To make incremental water quality improvements, it is important that states' and authorized tribes' WQS continue to reflect the ultimate water quality goal. This rule, therefore, requires states and authorized tribes to retain the underlying designated use and criterion in their standards to apply to all other permittees not addressed in the WQS variance, and for identifying threatened and impaired waters under CWA section 303(d), and for establishing a Total Maximum Daily Load (TMDL).[47] For further clarity, this rule also specifies that once EPA approves a WQS variance, including the highest attainable condition, it applies for purposes of developing NPDES permit limits and requirements under 301(b)(1)(C). WQS variances can also be used by states, authorized tribes, and other certifying entities when issuing certifications under CWA section 401. If EPA disapproves a WQS variance, the state or authorized tribe will have an opportunity to revise and re-submit the WQS variance for approval. Until EPA approves the re-submitted WQS variance, the underlying designated use and criteria remain applicable for all CWA purposes. This rule reinforces the requirements at § 122.44(d)(1)(vii)(A) by specifying that any limitations and requirements necessary to implement the WQS variance must be included as enforceable conditions of the implementing NPDES permit.

Second, to provide public transparency, this rule requires states and authorized tribes to include specific information in the WQS variance. States and authorized tribes must specify the pollutant(s) or water quality parameter(s) and the water body/waterbody segment(s) to which the WQS variance applies. A state or authorized tribe must also identify the discharger(s) subject to a discharger-specific WQS variance. As an alternative to identifying the specific dischargers at the time of adoption of a WQS variance for multiple dischargers, states and authorized tribes may adopt specific eligibility requirements in the WQS variance. This will make clear what characteristics a discharger must have in order to be subject to the WQS variance for multiple dischargers. It is EPA's expectation that states and authorized tribes that choose to identify the dischargers in this manner will subsequently make a list of the facilities covered by the WQS variance publicly available (*e.g.*, posted on the state or authorized tribal Web site). It may be appropriate for a state or authorized tribe to adopt one WQS variance that applies to multiple dischargers experiencing the same challenges in meeting their WQBELs for the same pollutant so long as the WQS variance is consistent with the CWA and § 131.14.[48] A multiple discharger WQS variance may not be appropriate or practical for all situations and can be highly dependent on the applicable pollutants, parameters, and/or permittees.

States and authorized tribes must also specify the term of any WQS variance to ensure that WQS variances are time-limited. States and authorized tribes have the flexibility to express the WQS variance term as a specific date (*e.g.*, expires on December 31, 2024) or as an interval of time after EPA-approval (*e.g.*, expires 10 years after EPA approval), as long as it is only as long as necessary to achieve the highest attainable condition. If, at the end of the WQS variance, the underlying designated use remains unattainable, the state or authorized tribe may adopt a subsequent WQS variance(s), consistent with the requirements of § 131.14.

To ensure that states and authorized tribes use WQS variances that continue to make water quality progress, the rule does not allow a WQS variance to lower currently attained ambient water quality, except in circumstances where a WQS variance will allow short-term lowering necessary for restoration activities consistent with § 131.14(b)(2)(i)(A)(*2*). Moreover, states and authorized tribes must specify in the WQS variance itself the interim requirements reflecting the highest attainable condition. Where a permittee cannot immediately meet the WQBEL derived from the terms of a WQS variance, the permitting authority can decide whether to provide a permit compliance schedule (where authorized) so the permittee can remain in compliance with its NPDES permit.[49] (See CWA section [502(17)] for a definition of "Schedules of compliance" and 40 CFR 122.47).[50] Any such compliance schedule must include a final effluent limit based on the applicable highest attainable condition and must require compliance with the permit's WQBEL "as soon as possible." If the compliance schedule exceeds one year, the permitting authority must include interim requirements and the dates for their achievement.

For example, if the underlying criterion requires an NPDES WQBEL of 1 mg/L for pollutant X, but the permittee's current effluent quality is at 10 mg/L, the state or authorized tribe could adopt the highest attainable condition of 3 mg/L to be achieved at the end of 15 years and obtain EPA approval if they have met the requirements of § 131.14. Once approved by EPA, the highest attainable condition of 3 mg/L is the applicable

[46] For this reason, states and authorized tribes are not required to adopt specific authorizing provisions into state or authorized tribal law before using WQS variances consistent with the federal regulation.

[47] See 78 FR 54533 (September 4, 2013).

[48] EPA has developed a list of Frequently Asked Questions addressing when a multiple discharger WQS variance may be appropriate and how a state or authorized tribe can develop a credible rationale for this type of WQS variance. *Discharger-specific Variances on a Broader Scale: Developing Credible Rationales for Variances that Apply to Multiple Dischargers*, EPA–820–F–13–012, March 2013.

[49] As an alternative to a permit compliance schedule, there may be other available mechanisms such as an administrative order.

[50] 78 FR 54532 (September 4, 2013).

criterion for purposes of deriving the NPDES WQBEL and developing the NPDES permit limits and requirements for the facility covered by the WQS variance. For this example, assume the permitting authority is developing the NPDES permit without allowing dilution (*i.e.*, applying the criterion end of pipe). In this case, the facility will need 15 years to implement the activities necessary to meet the limit based on the 3 mg/L. The permitting authority could include a 15 year compliance schedule with a final effluent limit based on 3 mg/L and an enforceable sequence of actions that the permitting authority determines are necessary to achieve the final effluent limit. As discussed later in this section, the documentation that a state or authorized tribe provides to EPA justifying the term of the WQS variance informs the permitting authority when determining the enforceable sequence of actions.

This rule requires states and authorized tribes to provide a quantifiable expression of the highest attainable condition. This requirement is an important feature of a WQS variance that facilitates development of NPDES permit limits and requirements and allows states, authorized tribes, and the public to track progress. This rule provides states and authorized tribes the flexibility to express the highest attainable condition as numeric pollutant concentrations in ambient water, numeric effluent conditions, or other quantitative expressions of pollutant reduction, such as the maximum number of combined sewer overflows that is achievable after implementation of a long-term control plan or a percent reduction in pollutant loads.

The final rule at § 131.14(b)(1)(ii) provides states and authorized tribes with different options to specify the highest attainable condition depending on whether the WQS variance applies to a specific discharger(s) or to a water body or waterbody segment. For a discharger(s)-specific WQS variance, the rule allows states and authorized tribes to express the highest attainable condition as an interim criterion without specifying the designated use it supports. EPA received comments suggesting that identifying both an interim use and interim criterion for a WQS variance is unnecessary. EPA agrees that the level of protection afforded by meeting the highest attainable criterion in the immediate area of the discharge(s) results in the highest attainable interim use at that location. Therefore, the highest attainable interim criterion is a reasonable surrogate for both the highest attainable interim use and interim criterion when the WQS variance applies to a specific discharger(s). For similar reasons, as explained in the preamble to the proposed rule, states and authorized tribes may choose to articulate the highest attainable condition as the highest attainable interim effluent condition.[51] Neither of these options, however, is appropriate for a WQS variance applicable to a water body or waterbody segment. Such a WQS variance impacts the water body or waterbody segment in a manner that is similar to a change in a designated use and, therefore, must explicitly articulate the highest attainable condition as the highest attainable interim designated use and interim criterion. A state's or authorized tribe's assessment of the highest attainable interim designated use and interim criterion for this type of WQS variance necessarily involves an evaluation of all pollutant sources.

Where the state or authorized tribe cannot identify an additional feasible pollutant control technology, this rule provides options for articulating the highest attainable condition using the greatest pollutant reduction achievable with optimization of currently installed pollutant control technologies and adoption and implementation of a Pollutant Minimization Program (PMP). The rule makes this option available for a WQS variance that applies to a specific discharger(s) as well as a WQS variance applicable to a water body or waterbody segment. EPA defines PMP at § 131.3(p) as follows: "*Pollutant Minimization Program*, in the context of § 131.14, is a structured set of activities to improve processes and pollutant controls that will prevent and reduce pollutant loadings . . . ." Pollutant control technologies represent a broad set of pollutant reduction options, such as process or raw materials changes and pollution prevention technologies, practices that reduce pollutants prior to entering the wastewater treatment system, or best management practices for restoration and mitigation of the water body. This option requires states and authorized tribes to adopt the PMP along with other elements that comprise the highest attainable condition. As part of the applicable WQS, the permitting authority must use the PMP (along with the quantifiable expression of the "greatest pollutant reduction achievable") to derive NPDES permit limits and requirements.

As discussed later in this section, states and authorized tribes must reevaluate WQS variances on a regular and predictable schedule. To ensure that a WQS variance reflects the highest attainable condition throughout the WQS variance term, states and authorized tribes must adopt a provision specifying that the applicable interim WQS shall be either the highest attainable condition initially adopted, or a higher attainable condition later identified during any reevaluation. The rule requires such a provision only for WQS variances longer than five years. This provision must be self-implementing so that if any reevaluation yields a more stringent attainable condition, that condition becomes the applicable interim WQS without additional action. Upon permit reissuance, the permitting authority will base the WQBEL on the more stringent interim WQS consistent with the NPDES permit regulation at § 122.44(d)(vii)(A). Where the reevaluation identifies a condition less stringent than the highest attainable condition, the state or authorized tribe must revise the WQS variance consistent with CWA requirements and obtain EPA approval of the WQS variance before the permitting authority can derive a WQBEL based on that newly identified highest attainable condition.

Third, to ensure EPA has sufficient information to determine whether the WQS variance is consistent with EPA's WQS regulation, states and authorized tribes must provide documentation to justify why the WQS variance is needed, the term for the WQS variance, and the highest attainable condition. For a WQS variance to a designated use specified in CWA section 101(a)(2) and sub-categories of such uses, states and authorized tribes must demonstrate that the use and criterion are not feasible to attain on the basis of one of the factors listed in § 131.10(g) or on the basis of the new restoration-related factor in § 131.14(b)(2)(i)(A)(*2*). EPA added this new factor for when states and authorized tribes wish to obtain a WQS variance because they expect a time-limited exceedance of a criterion when removing a dam or during significant wetlands, lake, or stream reconfiguration/restoration efforts. EPA includes "lake" in the regulatory language for this factor, on the basis of public comments suggesting that the rule also apply to lake restoration activities. States and authorized tribes may only use this factor to justify the time necessary to remove the dam or the length of time in which wetland, lake, or stream restoration activities are actively on-going. Although such a WQS

[51] 78 FR 54534 (September 4, 2013).

variance might not directly impact an NPDES permittee or the holder of a federal license or permit, states and authorized tribes could rely on the WQS variance when deciding whether to issue a CWA section 401 certification in connection with an application for a federal license or permit. The central feature of CWA section 401 is the state or authorized tribe's ability to grant, grant with conditions, deny or waive certification for federally licensed or permitted activities that may discharge into navigable waters. Many states and authorized tribes rely on CWA section 401 certification to ensure that federal projects do not cause adverse water quality impacts. By adopting a WQS variance, the state or authorized tribe lays the groundwork for issuing a certification (possibly with conditions, as per CWA section 401(d)) that allows a federal license or permit to be issued. Without a WQS variance, the state or authorized tribe's only options might be to deny certification which prevents issuance of the federal license or permit, or waive certification and allow the license or permit to be issued without conditions. If a state or authorized tribe issues a CWA certification based on a WQS variance, EPA recommends that the state or tribe consider whether to include the applicable interim requirements from the WQS variance as conditions of its certification.

For WQS variances to non-101(a)(2) uses, this rule specifies that states and authorized tribes must document and submit a use and value demonstration consistent with § 131.10(a) (see section II.B for additional discussion on use and value demonstrations). EPA's proposed rule would have required that a "[s]tate must submit a demonstration justifying the need for a WQS variance" and the preamble to the proposed rule noted that the demonstrations for uses specified in CWA section 101(a)(2) and non-101(a)(2) may differ. EPA received comments questioning the requirements for WQS variances to non-101(a)(2) uses and this rule explicitly makes clear that the documentation requirement for removing or adopting new or revised designated uses in §§ 131.10(a) and 131.6 also applies to non-101(a)(2) WQS variances. States and authorized tribes may also use the factors at § 131.14(b)(2)(i)(A) to justify how their consideration of the use and value appropriately supports the WQS variance.

States and authorized tribes must justify the term of any WQS variance on the basis of the information and factors evaluated to justify the need for the WQS variance. States and authorized tribes must also describe the pollutant control activities, including those identified through a PMP, that the state or authorized tribe anticipates implementing throughout the WQS variance term to achieve the highest attainable condition. During its review of the WQS variance, EPA will evaluate this description of activities which must reflect only the time needed to plan activities, implement activities, or evaluate the outcome of activities. Explicitly requiring the state or authorized tribe to document the relationship between the pollutant control activities and the WQS variance term ensures that the term is only as long as necessary to achieve the highest attainable condition and that water quality progress is achieved throughout the entire WQS variance term. The pollutant control activities specified in the supporting documentation serve as milestones for the WQS variance and inform the permitting authority when developing the enforceable terms and conditions of the NPDES permit necessary to implement the WQS variance, as required at 40 CFR 122.44(d)(1).

The degree of certainty associated with pollutant control activities and pollutant reductions will inform EPA's review and evaluation of whether the state's or authorized tribe's submission sufficiently justifies the need and the term of WQS variances. There can be instances where a state or authorized tribe has information to determine that the underlying designated use and criterion cannot be attained for a particular period of time, but does not have sufficient information to identify the highest attainable condition that would be achieved in that same period of time. In such cases, EPA anticipates that a state or authorized tribe will adopt a shorter WQS variance reflecting the highest attainable condition that is supported by the available information, including the pollutant control activities identified in the WQS submission. States and authorized tribes could then determine the appropriate mechanism to continue making progress towards the underlying designated use and criterion, which may include adoption of subsequent WQS variances as more data are gathered and additional pollutant control activities are identified.

This rule also includes two additional requirements to ensure states and authorized tribes use all relevant information to establish a WQS variance for a water body or waterbody segment. States and authorized tribes must identify and document cost-effective and reasonable BMPs for nonpoint sources, and provide for public notice and comment on that documentation. States and authorized tribes must also document whether and to what extent BMPs were implemented and the water quality progress achieved during the WQS variance term to justify a subsequent WQS variance. Nonpoint sources can have a significant bearing on whether the designated use and associated criteria for the water body are attainable. It is essential for states and authorized tribes to consider how controlling these sources through application of cost-effective and reasonable BMPs could impact water quality before adopting such a WQS variance. Doing so informs the highest attainable condition, the duration of the WQS variance term, and the state's or authorized tribe's assessment of the interim actions that may be needed to make water quality progress.

Fourth, to ensure that states and authorized tribes thoroughly reevaluate each WQS variance with a term longer than five years, this rule requires states and authorized tribes to specify, in the WQS variance, the reevaluation frequency and how they plan to obtain public input on the reevaluation. Additionally, they must submit the results of the reevaluation to EPA within 30 days of completion. States and authorized tribes may specify the frequency of reevaluations to coincide with other state and authorized tribal processes (*e.g.*, WQS triennial reviews or NPDES permit reissuance), as long as reevaluations occur at least every five years. Although EPA does not review and approve or disapprove the results of a WQS variance reevaluation, the results could inform whether the Administrator exercises his or her discretion to determine that new or revised WQS are necessary. The rule also requires states and authorized tribes to adopt a provision specifying that the WQS variance will no longer be the applicable WQS for CWA purposes if they do not conduct the required reevaluation or do not submit the results of the reevaluation within 30 days of completion. If a state or authorized tribe does not reevaluate the WQS variance or does not submit the results to EPA within 30 days, the underlying designated use and criterion become the applicable WQS for the permittee(s) or water body specified in the WQS variance without EPA, states or authorized tribes taking an additional WQS action. In such cases, subsequent NPDES WQBELs for the associated permit must be based on the underlying designated use and criterion rather than the highest attainable condition, even if the originally specified variance term has not expired. As discussed earlier in this section, states and authorized tribes must also adopt a provision that ensures the WQS variance reflects the highest attainable condition initially adopted or any more stringent highest attainable condition identified during a reevaluation that is applicable throughout the WQS variance term.

EPA proposed a maximum allowable WQS variance term of 10 years to ensure that states and authorized tribes reevaluate long-term WQS challenges at least every 10 years before deciding whether to continue with a WQS variance. EPA explained in the preamble to the proposed rule that the purpose of this maximum WQS variance term was as follows: "Establishing an expiration date will ensure that the conditions of a [WQS] variance will be thoroughly reevaluated and subject to a public review on a regular and predictable basis to determine (1) whether conditions have changed such that the designated use and criterion are now attainable; (2) whether new or additional information has become available to indicate that the designated use and criterion are not attainable in the future (*i.e.*, data or information supports a use change/refinement); or (3) whether feasible progress is being made toward the designated use and criterion and that additional time is needed to make further progress (*i.e.*, whether a [WQS] variance may be renewed)." [52]

Some commenters suggested that 10 years is too long and does not provide adequate assurance that the state or authorized tribe will periodically reevaluate a WQS variance in a publicly transparent manner. Other commenters suggested that 10 years is too short because states often adopt WQS variances through conventional rulemaking processes and that such a maximum term would result in unnecessary rulemaking burden where it is widely understood that long-term pollution challenges require more time to resolve. A 10-year maximum could also discourage the use of WQS variances.

In response, EPA concludes that establishing specific reevaluation requirements for WQS variances longer than five years is the best way to achieve EPA's policy objective of active, thorough, and transparent reevaluation by states and authorized tribes while minimizing rulemaking burden. The reevaluation requirements in this rule eliminate the need to specify a maximum WQS variance term because they ensure the highest attainable condition is always the applicable WQS throughout the WQS variance term, thus driving incremental improvements toward the underlying designated use. These requirements also ensure the public has an opportunity to provide input throughout the WQS variance term. EPA chose five years as the maximum interval between reevaluations because five years is the length of a single NPDES permit cycle, allowing the reevaluation to inform the permit reissuance process. Although this rule does not specify a maximum WQS variance term, states and authorized tribes must still identify the WQS variance term and provide documentation demonstrating that the term is only as long as necessary to achieve the highest attainable condition. EPA will use this information to determine whether to approve or disapprove the WQS variance submitted for review, based on the requirements in § 131.14.

WQS variances remain subject to the triennial review and public participation requirements specified in § 131.20. The final rule requirements ensure that the public has the opportunity to work with states and authorized tribes in a predictable and timely manner to search for new or updated data and information specific to the WQS variance that could indicate a more stringent highest attainable condition exists than the state or authorized tribe originally adopted. "New or updated data and information" include, but are not limited to, new information on pollutant control technologies, changes in pollutant sources, flow or water levels, economic conditions, and BMPs that impact the highest attainable condition. Where there is an EPA-approved WQS variance, the permitting authority must refer to the reevaluation results when reissuing NPDES permits to ensure the permit implements any more stringent applicable WQS that the reevaluation provides. States and authorized tribes can facilitate this coordination by publishing and making accessible the results of reevaluations.

While this rule only requires reevaluations of WQS variances with a term longer than five years, states and authorized tribes must review all WQS variances during their triennial review. If a state or authorized tribe synchronizes a WQS variance reevaluation with permit reissuance, the reevaluation must occur on schedule even if there is a delay in the permit reissuance.

EPA previously promulgated specific variance procedures when EPA established federal WQS for Kansas (§ 131.34(c)) and Puerto Rico (§ 131.40(c)). To provide national consistency, this rule authorizes the Regional Administrator to grant WQS variances in Kansas and Puerto Rico in accordance with the provisions of § 131.14.

What did EPA consider?

In addition to considering the option EPA proposed, EPA considered options that provide a maximum WQS variance term more than or less than 10 years. EPA rejected these options because retaining a maximum term of any duration does not accomplish EPA's goal of a balanced approach that ensures both flexibility and accountability as effectively as requiring periodic reevaluations of the WQS variance. Additionally, on the basis of commenters' suggestions, EPA considered requiring identification and documentation of cost-effective and reasonable BMPs for nonpoint sources for all WQS variances and not just for WQS variances applicable to a water body or waterbody segment. To achieve EPA's policy objectives, EPA chose instead to add a requirement for all WQS variances that states and authorized tribes describe the pollutant control activities to achieve the highest attainable condition (see § 131.14(b)(2)(ii)).

What is EPA's position on certain public comments?

EPA received comments that suggested confusion between WQS variances and NPDES permit compliance schedules. WQS variances can be appropriate to address situations where it is known that the designated use and criterion are unattainable today, but progress could be made toward attaining the designated use and criterion. Typically, a permit authority grants a permit compliance schedule when the permittee needs additional time to modify or upgrade treatment facilities in order to meet its WQBEL based on the applicable WQS (*i.e.*, designated use and criterion). After the effective date of this rule, a permit authority could also grant a permit compliance schedule when the permittee needs additional time to meet its WQBEL based on the applicable WQS variance (*i.e.*, highest attainable condition) such that a schedule and resulting milestones will lead to compliance with the effluent limits derived from the WQS variance "as soon as possible." If a WQS variance is about to expire and a state or authorized tribe concludes the underlying designated use is now attainable, it is not appropriate for the state or authorized tribe to adopt a subsequent

[52] 78 FR 54536 (September 4, 2013).

WQS variance. However, if a permittee is unable to immediately meet a WQBEL consistent with the now attainable WQS, and the permitting authority can specify an enforceable sequence of actions that would result in achieving the WQBEL, the permitting authority could grant a permit compliance schedule consistent with § 122.47. If the underlying designated use is still not attainable, the state or authorized tribe can adopt a subsequent WQS variance.

EPA also received comments questioning how a WQS variance works with a TMDL and CWA section 303(d) impaired waters listing(s). These comments suggested the proposed rule creates a conflict in how the NPDES permitting regulation requires permitting authorities to develop WQBELs. Section 122.44(d)(1)(vii)(A) specifies that all WQBELs in an NPDES permit must derive from and comply with all applicable WQS. Section 122.44(d)(1)(vii)(B) specifies that the WQBEL of any NPDES permit must be consistent with the assumptions and requirements of any *available* (emphasis added) waste load allocation (WLA) in an EPA-approved or EPA-established TMDL. Because the WLA of the TMDL is based on the underlying designated use and criterion (and not the highest attainable condition established in the WQS variance), then the WLA in the TMDL is not available to the permittee covered by the WQS variance for NPDES permitting purposes while the WQS variance is in effect. The permitting authority must develop WQBELs for the permittees subject to the WQS variance based on the interim requirements specified in the WQS variance. Upon termination of the WQS variance, the NPDES permit must again derive from and comply with the underlying designated use and criterion and be consistent with the assumptions and requirements of the WLA (as it is again "available").

Some commenters questioned what would happen if a state or authorized tribe does not coordinate a WQS variance term with the expiration date of an NPDES permit. If information is available to the permitting authority indicating that the term of a WQS variance will end during the permit cycle, the permitting authority must develop two WQBELs: one WQBEL based on the highest attainable condition applicable throughout the WQS variance term, and another WQBEL based on the underlying designated use and criterion to apply after the WQS variance terminates. Including two sets of WQBELs that apply at different time periods in the permit ensures that the permit will derive from and comply with WQS throughout the permit cycle. If the state or authorized tribe adopts and EPA approves a subsequent WQS variance during the permit term to replace an expiring WQS variance, the new WQS variance would constitute "new regulations" pursuant to § 122.62(a)(3)(i), and the permitting authority could modify the permit to derive from and comply with the subsequent WQS variance. At the request of the permittee, the permitting authority can also utilize the Permit Actions condition specified in § 122.41(f) to modify a permit and revise the WQBEL to reflect the new WQS variance.

Some commenters questioned whether states and authorized tribes must modify WQS variances that states and authorized tribes adopted before the effective date of the final rule. States and authorized tribes must meet the requirements of this rule on the effective date of the final rule. As with any WQS effective for CWA purposes, WQS variances are subject to the triennial review requirements at § 131.20(a). When a state or authorized tribe reviews a WQS variance that was adopted before § 131.14 becomes effective, EPA strongly encourages the state or authorized tribe to ensure the WQS variance is consistent with this rule. EPA encourages the public to engage in triennial reviews and request revisions to WQS variances that states and authorized tribes adopted and EPA approved prior to the effective date of the final rule so that the public can provide information supporting the need to modify the WQS variances. Some states and authorized tribes may also have adopted binding WQS variance policies and/or procedures. Such policies and procedures are not required by EPA's regulation before utilizing WQS variances, however, where state and authorized tribes have them and they are inconsistent with this rule, those states and authorized tribes must revise such policies and/or procedures prior to, or simultaneously with, adopting the first WQS variance after the effective date of the final rule.

A state or authorized tribe may be able to streamline its WQS variance process in several ways. As discussed earlier in this section, one way is to adopt multiple discharger WQS variances. In justifying the need for a multiple discharger WQS variance, states and authorized tribes should account for as much individual permittee information as possible. A permittee that cannot qualify for an individual WQS variance cannot qualify for a multiple discharger WQS variance. EPA recommends that states and authorized tribes provide a list of the dischargers covered under the WQS variance on their Web sites or other publicly available sources of state or authorized tribal information, particularly when using multiple discharger WQS variances.

A second way is to adopt an administrative procedure that fulfills the WQS submittal and review requirements and specifies that if the state or authorized tribe follows the procedure, the WQS variance is legally binding under state or tribal law. A state or authorized tribe could submit such an administrative procedure for a WQS variance, as a rule, to EPA for review and approval under § 131.13. Once approved, the state or authorized tribe can follow this administrative procedure and develop a final document for each WQS variance. Because the state or tribal law specifies this WQS variance document is legally binding, there is no need for the state or authorized tribe to do a separate rulemaking for each individual WQS variance. Rather, the state or authorized tribe could submit each resulting WQS variance document, with an Attorney General or appropriate tribal legal authority certification, and EPA could take action under CWA section 303(c).

Some commenters questioned how this rule affects states and authorized tribes under the 1995 Great Lakes Water Quality Guidance (GLWQG)[53] because those requirements are different than the WQS variance requirements in the final rule. For waters in the Great Lakes basin, states and authorized tribes must meet the requirements of both 40 CFR parts 131 and 132. The practical effect of this requirement is that, where regulations in 40 CFR parts 131 and 132 overlap, the more stringent regulation applies. In some cases, the flexibilities and requirements in the national rule will not be applicable to waters in the Great Lakes basin. For example, the GLWQG limits any WQS variance to a maximum term of five years (with the ability to obtain a subsequent WQS variance). Therefore, any WQS variance on waters that are subject to the GLWQG cannot exceed five years even though the final rule in 40 CFR part 131 does not specify a maximum term. On the other hand, because GLWQG WQS variances cannot exceed five years, the requirements in the final rule that pertain to conducting reevaluations (for WQS variances greater than five years) are not applicable.

[53] See 60 FR 15366 (March 23, 1995); 40 CFR part 132.

Finally, some commenters questioned the level of "scientific rigor" required for a WQS variance as compared to a UAA required for changes to 101(a)(2) uses. Section 40 CFR 131.5(a)(4) provides that EPA's review under section 303(c) involves a determination of whether the state's or authorized tribe's "standards which do not include the uses specified in section 101(a)(2) of the Act are based upon appropriate technical and scientific data and analyses. . . ." Because WQS variances are time-limited designated uses and criteria, this requirement applies to WQS variances. States and authorized tribes must adopt WQS variances based on appropriate technical and scientific data and analyses. Therefore, the level of rigor required for a WQS variance is no different than for a designated use change. That said, the appropriate technical and scientific data required to support a designated use change and WQS variance can vary depending on the complexity of the specific circumstances. EPA recognizes that the data and analyses often needed to support adoption of a WQS variance could be less complex and require less time and resources compared to removing a designated use because many WQS variances evaluate only one parameter for a single permittee for a limited period of time. The level of effort a state or authorized tribe needs to devote to a WQS variance will in large part be determined by the complexity of the water quality problem the state or authorized tribe seeks to address.

F. Provisions Authorizing the Use of Schedules of Compliance for WQBELs in NPDES Permits

What does this rule provide and why?

In 1990, EPA concluded that before a permitting authority can include a compliance schedule for a WQBEL in an NPDES permit, the state or authorized tribe must affirmatively authorize its use in its WQS or implementing regulations.[54] EPA approval of the state's or authorized tribe's permit compliance schedule authorizing provision as a WQS ensures that any NPDES permit WQBEL with a compliance schedule derives from and complies with applicable WQS as required by § 122.44(d)(1)(vii)(A). Because the state's or authorized tribe's approved WQS authorize extended compliance, any delay in compliance with a WQBEL pursuant to an appropriately issued permit compliance schedule is consistent with the statutory implementation timetable in CWA section 301(b)(1)(C).

The use of legally-authorized permit compliance schedules by states and authorized tribes provides needed flexibility for many dischargers undergoing facility upgrades and operational changes designed to meet WQBELs in their NPDES permits. This flexibility will become increasingly important as states and authorized tribes adopt more stringent WQS, including numeric nutrient criteria, and address complex water quality problems presented by emerging challenges like climate change.

Some states have adopted compliance schedule authorizing provisions but have not submitted them to EPA for approval as WQS pursuant to CWA section 303(c). Other states have not yet adopted compliance schedule authorizing provisions. A permit could be subject to legal challenge where a state and authorized tribe decide to authorize permit flexibility using permit compliance schedules, but do not have a compliance schedule authorizing provision approved by EPA as a WQS.

Section 131.15 in this final rule requires that if a state or authorized tribe intends to authorize the use of compliance schedules for WQBELs in NPDES permits, it must first adopt a permit compliance schedule authorizing provision. The authorizing provision must be consistent with the CWA and is subject to EPA review and approval as a WQS. This rule adds § 131.5(a)(5) to explicitly specify that EPA has the authority to determine whether any provision authorizing the use of schedules of compliance for WQBELs in NPDES permits adopted by a state or authorized tribe is consistent with the requirements at § 131.15. This rule also includes a number of non-substantive editorial changes.

By expressly requiring that the state or authorized tribe adopt a permit compliance schedule authorizing provision, the first sentence of the final regulation at § 131.15 ensures that the state or authorized tribe has expressly made a determination that, under appropriate circumstances, it can be lawful to delay permit compliance. Formal adoption as a legally binding provision ensures public transparency and facilitates public involvement.

Some commenters expressed concern that the proposed regulatory language regarding state and authorized tribal adoption could be interpreted to refer to permit compliance schedules themselves, rather than their authorizing provisions. To address that concern, the final rule refers to "the use of" schedules of compliance. The phrase "the use of" indicates that the mere adoption of an authorizing provision, by itself, does not extend the date of compliance with respect to any specific permit's WQBEL; rather, its adoption allows the state or authorized tribe *to use* schedules of compliance, as appropriate, on a case-by-case basis in individual permits.

The second sentence of the final regulation at § 131.15 provides that states' and authorized tribes' authorizing provisions must be consistent with the CWA and are WQS subject to EPA review and approval. By incorporating the authorizing provision into the state's or authorized tribe's approved WQS, the state or authorized tribe ensures that a permitting authority can then legally issue compliance schedules for WQBELs in NPDES permits that are consistent with CWA section 301(b)(1)(C). Only the permit compliance schedule authorizing provisions are WQS subject to EPA approval; individual permit compliance schedules are not. The final rule provides flexibility for a state or authorized tribe to include the authorizing provision in the part of state or tribal regulations where WQS are typically codified, in the part of state or tribal regulations dealing with NPDES permits, or in other parts of the state's or authorized tribe's implementing regulations. Regardless of where the authorizing provision is codified, as long as the provision is legally binding, EPA will take action on it under CWA section 303(c). If a state or authorized tribe has already adopted an authorizing provision that is consistent with the CWA, it need not readopt the provision for purposes of satisfying the final rule. Instead, the state or authorized tribe can submit the provision to EPA with an Attorney General or appropriate tribal legal authority certification. Moreover, consistent with § 131.21(c), any permit compliance schedule authorizing provision that was adopted, effective, and submitted to EPA before May 30, 2000, is applicable for purposes of § 131.15.

This final rule does not change any permit compliance schedule requirements at § 122.47.

Other judicial and administrative mechanisms issued pursuant to other authorities, such as an enforcement order issued by a court, can delay the need for compliance with WQBELs. This rule does not address those other mechanisms.

What did EPA consider?

EPA considered finalizing § 131.15, as proposed. Given the comments

[54] *In the Matter of Star-Kist Caribe, Inc.* 3 EAD 172 (April 16, 1990).

indicating that ambiguity in the proposed language could lead to confusion over whether the requirements to adopt and submit for EPA approval applied directly to permit compliance schedules themselves, EPA did not select this option. Instead, EPA added clarifying language to address the commenters' concern and streamlined the text of the proposed rule without making substantive changes. EPA also considered foregoing the addition of § 131.15. Many commenters, however, supported adding § 131.15 as a useful clarification of the need and process for states and authorized tribes to adopt compliance schedule authorizing provisions.

What is EPA's position on certain public comments?

Some commenters said that the following proposed regulatory language—"authorize schedules of compliance *for water quality-based effluent limits (WQBELs)* in NPDES permits"—could have the effect of narrowing the universe of NPDES permits and permit requirements for which permitting authorities can include permit compliance schedules. The regulation does not narrow that universe, nor does it preclude other appropriate uses of permit compliance schedules as provided for in § 122.47. The new § 131.15 requirements only apply to the authorization of compliance schedules *for WQBELs* in NPDES permits. Such WQBELs are designed to meet WQS established by the state or authorized tribe and approved by EPA under CWA section 303(c).[55] Adding this new provision to the WQS regulation will ensure that the state or authorized tribe takes the necessary steps to ensure that any NPDES permit with a permit compliance schedule for a WQBEL is consistent with the state's or authorized tribe's applicable WQS. The requirement in § 131.15 does not preclude, or apply to, use of compliance schedules for permit limitations or conditions that are not WQBELs. A permitting authority can grant a permit compliance schedule for non-WQBEL NPDES permit limits or conditions without an EPA-approved authorizing provision, provided the permit compliance schedule is consistent with the CWA, EPA's permitting regulation, especially §§ 122.2 and 122.47, and any applicable state or tribal laws and regulations. Permitting authorities can include such permit compliance schedules without an EPA-approved permit compliance schedule authorizing provision because such limits and conditions are not themselves designed to implement the state's or authorized tribe's approved WQS.

[55] 40 CFR 122.44(d)(1); 122.44(d)(1)(vii)(A).

G. Other Changes

What does this rule provide and why?

Regulatory provisions can only be effective if they are clear and accurate. Even spelling and grammar mistakes, and inconsistent terminology can cause confusion. This rule, therefore, corrects these types of mistakes and inconsistencies in the following 11 regulatory provisions: §§ 131.2, 131.3(h), 131.3(j), 131.5(a)(1), 131.5(a)(2), 131.10(j), 131.10(j)(2), 131.11(a)(2), 131.11(b), 131.12(a)(2), and 131.20(b). The rule finalizes eight of the provisions, as proposed. However, based on public comments, EPA revised how it is correcting §§ 131.5(a)(2), 131.12(a)(2), and 131.20(b). EPA notes that in correcting these minor pre-existing errors, it did not re-examine the substance of these regulatory provisions. Thus EPA did not reopen these regulatory provisions.

With regard to the revision at § 131.5(a)(2), the final rule adds a reference to § 131.11 and "sound scientific rationale" to make the link clear. Commenters expressed concern that "sound scientific rationale" was an ambiguous and subjective point of reference and may interfere with the ability of states and authorized tribes to use narrative criteria. By linking the two regulatory sections, this rule makes clear that this provision does not contradict the requirements and flexibilities provided in § 131.11.

This rule at § 131.12(a)(2) correctly cites to the CWA language and makes no other changes. EPA proposed revising "assure" to "ensure," however, the final rule does not include this change. Commenters raised the question of whether the revision changed the meaning of the provision. Although both "assure" and "ensure" mean "to make sure," EPA recognizes that the context surrounding the word is important. While "ensure" is used in § 131.10(b), in this context, the states and authorized tribes can "make sure" their WQS meet the regulatory requirements. However, § 131.12(a)(2), addresses water quality, not WQS. While states and authorized tribes have control over their WQS, they do not have the same control over the resulting water quality as it can be affected by many other factors. So use of the word "ensure" would not be appropriate in this provision.

This rule clarifies four points related to public hearings. First, it clarifies that 40 CFR part 25 is EPA's public participation regulation that sets the minimum requirements for public hearings and removes the nonexistent citation to "EPA's water quality management regulation (40 CFR 130.3(b)(6))." Second, it clarifies that holding one public hearing may satisfy the legal CWA requirement although states and authorized tribes may hold multiple hearings. The purpose of this revision is to provide consistency with the language of CWA section 303(c)(1) and § 131.20(a), not to create a requirement that states and authorized tribes must hold multiple hearings when reviewing or revising WQS. Third, EPA's corresponding change in § 131.5(a)(6) clarifies that EPA's authority in acting on revised or new WQS includes determining whether the state or authorized tribe has followed the "applicable" legal procedures. Applicable legal procedures include those required by the CWA and EPA's implementing regulations. In particular, states and authorized tribes must comply with the requirement in § 131.20(b) to hold a public hearing in accordance with 40 CFR part 25 when reviewing or revising WQS. The purpose of the § 131.20(b) requirements is to implement the CWA and provide an opportunity for meaningful public input when states or authorized tribes develop WQS, which is an important step to ensure that adopted WQS reflect full consideration of the relevant issues raised by the public. Finally, § 131.20(b) and EPA's corresponding deletion of § 131.10(e) clarify that a public hearing is required when (1) reviewing WQS per § 131.20(a); (2) when revising WQS as a result of reviewing WQS per § 131.20(a); and (3) whenever revising WQS, regardless of whether the revision is a result of triennial review per § 131.20(a). EPA reviewed the use of the phrase "an opportunity for a public hearing" used in § 131.10(e) and found that such language contradicts the CWA and § 131.20(b). Therefore, EPA is deleting this provision as a conforming edit to its clarifications in § 131.20(b). As suggested by commenters, EPA replaced its proposed language of "reviewing or revising" to "reviewing as well as when revising" to make clear that public participation is required in all of these circumstances.

What is EPA's position on certain public comments?

A commenter requested that EPA further revise the regulation to allow states and authorized tribes to gather public input in formats other than public hearings (*e.g.*, public meetings, webinars). Although EPA acknowledges the challenges that states and authorized tribes may experience when planning and conducting a public hearing, the requirement to hold hearings for the purposes of reviewing, and as appropriate, modifying and adopting WQS comes directly from CWA section 303(c)(1). Further, meaningful involvement of the public and intergovernmental coordination with local, state, federal, and tribal entities with an interest in water quality issues is an important component of the WQS process. States and authorized tribes have discretion to use other outreach efforts in addition to fulfilling the requirement for a public hearing.

A "public hearing" may mean different things to different people. At a minimum, per § 131.20(b), states and authorized tribes are required to follow the provisions of state or tribal law and EPA's public participation regulations at 40 CFR part 25. EPA's public participation regulation, at 40 CFR 25.5, sets minimum requirements for states and authorized tribes to publicize a hearing at least 45 days prior to the date of the hearing; provide to the public reports, documents, and data relevant to the discussion at the public hearing at least 30 days before the hearing; hold the hearing at times and places that facilitate attendance by the public; schedule witnesses in advance to allow maximum participation and adequate time; and prepare a transcript, recording, or other complete record of the hearing proceedings. See 40 CFR 25.5 for the actual list of federal public hearing requirements. State and tribal law may include additional requirements for states and authorized tribes to meet when planning for and conducting a hearing. In addition to meeting the requirements of state and tribal law and 40 CFR part 25, states and authorized tribes may also choose to gather public input using other formats, such as public meetings and webinars.

III. Economic Impacts on State and Authorized Tribal WQS Programs

EPA evaluated the potential incremental administrative burden and cost that may be associated with the final rule, beyond the burden and cost of the WQS regulation already in place. EPA's estimate is higher than the estimate of the proposed rule for two reasons unrelated to any substantive change in requirements. First, EPA obtained more precise estimates of burden and costs. EPA received many comments suggesting that EPA underestimated the burden and cost of the proposed rule. States specifically requested to meet with EPA to provide additional information for EPA to consider. EPA engaged the states and incorporated the information provided into the final economic analysis. The higher estimate is also partly due to EPA using known data to extrapolate burden and costs to states, territories and authorized tribes where data were unavailable. EPA describes the method of extrapolation in detail in the full economic analysis available in the docket of the final rule. EPA's economic analysis focuses on the potential administrative burden and cost to all 50 states, the District of Columbia, five territories, the 40 authorized tribes with EPA-approved WQS, and to EPA. While this rule does not establish any requirements directly applicable to regulated point sources or nonpoint sources of pollution, EPA acknowledges that this rule may result in indirect costs to some regulated entities as a result of changes to WQS that states and authorized tribes adopt based on the final rule. EPA is unable to quantify indirect costs and benefits since it cannot anticipate precisely how the rule will be implemented by states and authorized tribes and because of a lack of data. States and authorized tribes always have the discretion to adopt new or revised WQS independent of this final rule that could result in costs to point sources and nonpoint sources. EPA's economic analysis and an explanation for how EPA derived the cost and burden estimates are documented in the *Economic Analysis for the Water Quality Standards Regulatory Revisions (Final Rule)* and can be found in the docket for this rule.

EPA assessed the potential incremental burden and cost of this final rule using the same basic methodology used to assess the potential incremental burden and cost of EPA's proposed rule, including: (1) Identifying the elements of the final rule that could potentially result in incremental burden and cost; (2) estimating the incremental number of labor hours states and authorized tribes may need to allocate in order to comply with those elements of the final rule; and (3) estimating the cost associated with those additional labor hours.

EPA identified four areas where differences between the proposed and final rules affected burden and cost estimates. First, when states and authorized tribes submit the results of triennial reviews to EPA, they must provide an explanation when not adopting new or revised water quality criteria for parameters for which EPA has published new or updated CWA section 304(a) criteria recommendations. Second, when developing or revising antidegradation implementation methods and when deciding which waters would receive Tier 2 antidegradation protection under a water body-by-water body approach, states and authorized tribes must provide an opportunity for public involvement. States and authorized tribes must also document and keep in the public record the factors they considered when making those decisions. Third, the final rule no longer includes a maximum WQS variance duration of 10 years and thus eliminates the burden and cost associated with renewing a WQS variance when the state or authorized tribe can justify a longer term. Fourth, the final rule requires states and authorized tribes to proactively reevaluate WQS variances that have a term longer than five years no less frequently than every five years and to submit the results of each reevaluation to EPA within 30 days of completion. EPA also revised certain economic assumptions based on additional information obtained independently by EPA and in response to stakeholder feedback.

The potential incremental burden and cost of the final rule include five categories: (1) One-time burden and cost associated with state and authorized tribal rulemaking activities when some states and authorized tribes may need to adopt new or revised provisions into their WQS (*e.g.*, review currently adopted water quality standards to determine if the new requirements necessitate revisions, such as modifying antidegradation policy, revising WQS variance procedures if the state or authorized tribe has chosen to adopt such a procedure, or adopting a permit compliance schedule authorizing provision); (2) recurring burden and cost associated with removing uses specified in CWA section 101(a)(2) because states and authorized tribes must identify the HAU; (3) recurring burden and cost associated with triennial reviews whereby states and authorized tribes must prepare and submit an explanation when not adopting new or revised water quality criteria for parameters for which EPA has published new or updated CWA section 304(a) criteria recommendations; (4) recurring burden and cost associated with antidegradation requirements, including providing the opportunity for public involvement when developing and subsequently revising antidegradation implementation methods; providing the opportunity for public involvement when deciding which waters will receive Tier 2 antidegradation protection when using a water body-by-water body approach; documenting and keeping in the public record the factors the state or authorized tribe considered when deciding which waters will receive Tier 2 antidegradation protection; and performing/evaluating more extensive and a greater number of antidegradation reviews; and (5) recurring burden and cost associated with developing and documenting WQS variances for submission to EPA, and reevaluating WQS variances with a term longer than five years no less frequently than every five years. EPA did not estimate potential cost savings associated with a provision in the final rule that a UAA is not required when removing a non-101(a)(2) use because states and authorized tribes continue to have the discretion to conduct a UAA when removing such uses.

Estimates of the potential incremental burden and cost of this final rule are summarized in the following tables.

SUMMARY OF POTENTIAL INCREMENTAL BURDEN AND COST TO STATES AND AUTHORIZED TRIBES

Provision	One-time activities			Recurring activities	
	Burden (hours)	Cost (2013$ millions)	Annualized cost (2013$ millions/ year) [1]	Burden (hours/year)	Cost (2013$ millions/ year)
Rulemaking Activities	48,000–96,000	$2.35–$4.70	$0.16–$0.32	—	—
Designated Uses	—	—	—	2,250–4,500	$0.11–$0.22
Triennial Reviews	—	—	—	4,320–21,600	0.21–1.06
Antidegradation	6,450–12,900	0.32–0.63	0.02–0.04	48,015–143,400	2.37–7.02
WQS Variances	—	—	—	51,840–233,280	2.54–11.43
National Total	54,450–108,900	2.67–5.34	0.18–0.36	106,425–402,780	5.24–19.73

'—' = not applicable

Note: Individual annual cost estimates do not add to the total because of independent rounding.

[1] Although EPA expects one-time rulemaking activity costs to be incurred over an initial three-year period, it annualized costs at a three percent discount rate over 20 years for comparative purposes. See the *Economic Analysis for the Water Quality Standards Regulatory Revisions (Final Rule)* for the potential incremental burden and cost using a seven percent discount rate.

SUMMARY OF POTENTIAL INCREMENTAL BURDEN AND COST TO EPA [1]

One-time activities				Recurring activities		
Cost to the agency (2013$ million) [2]	Annualized cost to the agency (2013$ million per year) [3]	Burden		Cost to the agency (2013$ million per year) [6]	Burden	
		Hours [4]	FTEs [5]		Hours per year [4]	FTEs per year [5]
$0.53–$1.07	$0.04–$0.07	7,080–14,150	3.4–6.8	$1.05–$3.95	13,900–52,320	6.7–25.2

[1] Assuming that the incremental burden and costs to EPA are equal to 20 percent of the burden and costs to states and authorized tribes.

[2] $0.53 million ($2.67 million × 20 percent) to $1.07 million ($5.34 million × 20 percent)

[3] Although EPA expects these one-time costs to be incurred over an initial three-year period, the costs are annualized at three percent discount rate over 20 years for comparative purposes. See the *Economic Analysis for the Water Quality Standards Regulatory Revisions (Final Rule)* for the potential incremental burden and cost using a seven percent discount rate.

[4] Total costs to the Agency divided by hourly wage rate ($75.41 per hour).

[5] Burden hours to the Agency divided by hours worked by full-time equivalent (FTE) employees per year (2,080 hours per year).

[6] $1.05 million ($5.24 million × 20 percent) to $3.95 million ($19.73 million × 20 percent).

COMBINED SUMMARY OF POTENTIAL INCREMENTAL BURDEN AND COST TO STATES, AUTHORIZED TRIBES, AND EPA

Entities	One-time activities			Recurring activities	
	Burden (hours)	Cost (2013$ millions)	Annualized cost (2013$ million/ year) [1]	Burden (hours/year)	Cost (2013$ millions/ year)
States and Authorized Tribes	54,450–108,900	$2.67–$5.34	$0.18–$0.36	106,425–402,780	$5.24–$19.73
Agency	7,080–14,150	0.53–1.07	0.04–0.07	13,900–52,320	1.05–3.95
Total	61,530–122,050	3.20–6.40	0.22–0.43	120,325–455,100	6.29–23.68

Note: Individual annual cost estimates do not add to the total because of independent rounding.

[1] Although EPA expects states and authorized tribes to incur rulemaking costs over an initial three-year period, it annualized one-time costs at a three percent discount rate over 20 years for comparative purposes. See the *Economic Analysis for the Water Quality Standards Regulatory Revisions (Final Rule)* for the potential incremental burden and cost using a seven percent discount rate.

To estimate the total annual cost of this rule which includes both one-time cost and recurring cost, EPA annualized the one-time cost over a period of 20 years. Using a 20-year annualization period and a discount rate of three percent, EPA estimates the total annual cost for this final rule to range from $6.51 million per year ($0.22 million per year + $6.29 million per year) to $24.11 million per year ($0.43 million per year + $23.68 million per year).[56]

[56] See the *Economic Analysis for the Water Quality Standards Regulatory Revisions (Final Rule)* for the potential incremental burden and cost for this final rule using a seven percent discount rate.

EPA also evaluated the potential benefits associated with this rule. States and authorized tribes will benefit from these revisions because the WQS regulation will provide clear requirements to facilitate the ability of states and authorized tribes to effectively and legally utilize available regulatory tools when implementing and managing their WQS programs. Although associated with potential administrative burden and cost in some areas, this rule has the potential to partially offset these burdens by reducing regulatory uncertainty and increasing overall program efficiency. Use of these tools to improve establishment and implementation of state and authorized tribal WQS, as discussed throughout the preamble to this rule, provides incremental improvements in water quality and a variety of economic benefits associated with these improvements, including the availability of clean, safe, and affordable drinking water sources; water of adequate quality for agricultural and industrial use; and water quality that supports the commercial fishing industry and higher property values. Nonmarket benefits of this rule include greater recreational opportunities and the protection and improvement of public health. States, authorized tribes, stakeholders and the public will also benefit from the open public dialogue that results from the additional transparency and public participation requirements included in this rule. Because states and authorized tribes implement their own WQS programs, EPA could not reliably predict the control measures likely to be implemented and subsequent improvements to water quality, and thus could not quantify the resulting benefits.

IV. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

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

This action is a 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, *Economic Analysis for the Water Quality Standards Regulatory Revisions (Final Rule)*, is summarized in section III of the preamble and is available in the docket.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that EPA prepared has been assigned EPA ICR number 2449.02. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The core of the WQS regulation, established in 1983, requires EPA to collect certain information from states and authorized tribes and has an approved ICR (EPA ICR number 988.11; OMB Control number 2040–0049). This rule requires states and authorized tribes to submit certain additional information to EPA. This mandatory information collection ensures EPA has the necessary information to review WQS and approve or disapprove consistent with the rule. The goals of the rule can only be fulfilled by collecting this additional information. Due to the nature of this rule, EPA assumes that all administrative burden associated with this rule, summarized in section III, is associated with information collection.

Respondents/affected entities: The respondents affected by this collection activity include the 50 states, the District of Columbia, five territories, and 40 authorized tribes that have EPA-approved WQS. The respondents are in NAICS code 92411 "Administration of Air and Water Resources and Solid Waste Management Programs," formerly SIC code #9511.

Respondent's obligation to respond: The collection is required pursuant to CWA section 303(c), as implemented by the revisions to 40 CFR part 131.

Estimated number of respondents: A total of 96 governmental entities are potentially affected by the rule.

Frequency of response: The CWA requires states and authorized tribes to review their WQS at least once every three years and submit the results to EPA. In practice, some states and authorized tribes choose to submit revised standards for portions of their waters more frequently.

Total estimated burden: EPA estimates a total annual burden of 124,575–439,080 hours and 3,176 to 5,096 responses per year. Burden is defined at 5 CFR 1320.3(b). A "response" is an action that a state or authorized tribe would need to take in order to meet the information collection request provided in the rule (*e.g.*, documentation supporting a WQS variance). See also the "Information Collection Request for Water Quality Standards Regulatory Revisions (Final Rule)" in the docket for this rule.

Total estimated cost: Total estimated annual incremental costs range from $6.13 million to $21.51 million.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce the approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. State and authorized tribal governments responsible for administering or overseeing water quality programs may be directly affected by this rulemaking, as states and authorized tribes may need to consider and implement new provisions, or revise existing provisions, in their WQS. Small entities, such as small businesses or small governmental jurisdictions, are not directly regulated by this rule. This rule will not impose any requirements on small entities.

D. Unfunded Mandates Reform Act (UMRA)

This rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. EPA estimates total annual costs to states and authorized tribes to range from $5.24 million to $19.73 million per year. Thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. The rule finalizes regulatory revisions to provide clarity and transparency in the WQS regulation that may require state and local officials to reevaluate or revise their WQS. However, the rule will not impose substantial direct compliance costs on state or local governments, nor will it preempt state law. Thus, Executive Order 13132 does not apply to this action.

Keeping with the spirit of Executive Order 13132 and consistent with EPA's policy to promote communications between EPA and state and local governments, EPA consulted with state and local officials early in the process and solicited their comments on the proposed action and on the development of this rule.

Between September 2013 and June 2014, EPA consulted with representatives from states and intergovernmental associations at their request, to hear their views on the proposed regulatory revisions and how commenters' suggested revisions would impact implementation of their WQS programs. Some participants expressed concern that the proposed changes may impose a resource burden on state and local governments, as well as infringe on states' flexibility in the areas included in the proposed rule. Some participants urged EPA to ensure that states with satisfactory regulations in these areas are not unduly burdened by the regulatory revisions.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt tribal law. Thus, Executive Order 13175 does not apply to this action. To date, 50 Indian tribes have been approved for treatment in a manner similar to a state (TAS) for CWA sections 303 and 401. Of the 50 tribes, 40 have EPA-approved WQS in their respective jurisdictions. All of these authorized tribes are impacted by this regulation. However, this rule might affect other tribes with waters adjacent to waters with federal, state, or authorized tribal WQS.

EPA consulted and coordinated with tribal officials consistent with EPA's Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to allow them to provide meaningful and timely input into its development. In August 2010, November 2013, and October 2014, EPA held tribes-only consultation and coordination sessions to hear their views and answer questions of all interested tribes on the targeted areas EPA considered for regulatory revision. Tribes expressed the need for additional guidance and assistance in implementing the proposed rulemaking, specifically for development of antidegradation implementation methods and determination of the highest attainable use. EPA considered the burden to states and authorized tribes in developing this rule and, when possible, has provided direction and flexibility that allows tribes to address higher priority aspects of their WQS programs. EPA also intends to release updated guidance in a new edition of the WQS Handbook. A summary of the consultation and coordination is available in the docket for this rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045, because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

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

EPA has determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations, because it does not adversely affect the level of protection provided to human health or the environment. This rule does not directly establish WQS for a state or authorized tribe and, therefore, does not directly affect a specific population or a particular geographic area(s).

K. Congressional Review Act (CRA)

This action is subject to the CRA, and EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 131

Environmental protection, Indians—lands, Intergovernmental relations, Reporting and recordkeeping requirements, Water pollution control.

Dated: August 5, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, EPA amends 40 CFR part 131 as follows:

PART 131—WATER QUALITY STANDARDS

■ 1. The authority citation for part 131 continues to read as follows:

Authority: 33 U.S.C. 1251 *et seq.*

Subpart A—General Provisions

■ 2. In § 131.2, revise the first sentence to read as follows:

§ 131.2 Purpose.

A water quality standard defines the water quality goals of a water body, or portion thereof, by designating the use or uses to be made of the water and by setting criteria that protect the designated uses. * * *

* * * * *

■ 3. In § 131.3:

■ a. Revise paragraphs (h) and (j).

■ b. Add paragraphs (m), (n), (o), (p), and (q).

The revisions and additions read as follows:

§ 131.3 Definitions.

* * * * *

(h) *Water quality limited segment* means any segment where it is known that water quality does not meet applicable water quality standards, and/or is not expected to meet applicable water quality standards, even after the application of the technology-based effluent limitations required by sections 301(b) and 306 of the Act.

* * * * *

(j) *States* include: The 50 States, the District of Columbia, Guam, the Commonwealth of Puerto Rico, Virgin Islands, American Samoa, the Commonwealth of the Northern Mariana Islands, and Indian Tribes that EPA determines to be eligible for purposes of the water quality standards program.

* * * * *

(m) *Highest attainable use* is the modified aquatic life, wildlife, or recreation use that is both closest to the uses specified in section 101(a)(2) of the

Act and attainable, based on the evaluation of the factor(s) in § 131.10(g) that preclude(s) attainment of the use and any other information or analyses that were used to evaluate attainability. There is no required highest attainable use where the State demonstrates the relevant use specified in section 101(a)(2) of the Act and sub-categories of such a use are not attainable.

(n) *Practicable*, in the context of § 131.12(a)(2)(ii), means technologically possible, able to be put into practice, and economically viable.

(o) A *water quality standards variance* (WQS variance) is a time-limited designated use and criterion for a specific pollutant(s) or water quality parameter(s) that reflect the highest attainable condition during the term of the WQS variance.

(p) *Pollutant Minimization Program*, in the context of § 131.14, is a structured set of activities to improve processes and pollutant controls that will prevent and reduce pollutant loadings.

(q) *Non-101(a)(2) use* is any use unrelated to the protection and propagation of fish, shellfish, wildlife or recreation in or on the water.

■ 4. In § 131.5:
■ a. Revise paragraphs (a)(1) and (2).
■ b. Redesignate paragraphs (a)(3) through (5) as paragraphs (a)(6) through (8).
■ c. Add paragraphs (a)(3) through (5).
■ d. Revise newly designated paragraph (a)(6).
■ e. Revise paragraph (b).

The revisions and additions read as follows:

§ 131.5 EPA authority.

(a) * * *

(1) Whether the State has adopted designated water uses that are consistent with the requirements of the Clean Water Act;

(2) Whether the State has adopted criteria that protect the designated water uses based on sound scientific rationale consistent with § 131.11;

(3) Whether the State has adopted an antidegradation policy that is consistent with § 131.12, and whether any State adopted antidegradation implementation methods are consistent with § 131.12;

(4) Whether any State adopted WQS variance is consistent with § 131.14;

(5) Whether any State adopted provision authorizing the use of schedules of compliance for water quality-based effluent limits in NPDES permits is consistent with § 131.15;

(6) Whether the State has followed applicable legal procedures for revising or adopting standards;

* * * * *

(b) If EPA determines that the State's or Tribe's water quality standards are consistent with the factors listed in paragraphs (a)(1) through (8) of this section, EPA approves the standards. EPA must disapprove the State's or Tribe's water quality standards and promulgate Federal standards under section 303(c)(4), and for Great Lakes States or Great Lakes Tribes under section 118(c)(2)(C) of the Act, if State or Tribal adopted standards are not consistent with the factors listed in paragraphs (a)(1) through (8) of this section. EPA may also promulgate a new or revised standard when necessary to meet the requirements of the Act.

* * * * *

Subpart B—Establishment of Water Quality Standards

■ 5. In § 131.10:
■ a. Revise paragraphs (a), (g) introductory text, (j), and (k).
■ b. Remove and reserve paragraph (e).

The revisions read as follows:

§ 131.10 Designation of uses.

(a) Each State must specify appropriate water uses to be achieved and protected. The classification of the waters of the State must take into consideration the use and value of water for public water supplies, protection and propagation of fish, shellfish and wildlife, recreation in and on the water, agricultural, industrial, and other purposes including navigation. If adopting new or revised designated uses other than the uses specified in section 101(a)(2) of the Act, or removing designated uses, States must submit documentation justifying how their consideration of the use and value of water for those uses listed in this paragraph appropriately supports the State's action. A use attainability analysis may be used to satisfy this requirement. In no case shall a State adopt waste transport or waste assimilation as a designated use for any waters of the United States.

* * * * *

(e) [Reserved]

* * * * *

(g) States may designate a use, or remove a use that is *not* an existing use, if the State conducts a use attainability analysis as specified in paragraph (j) of this section that demonstrates attaining the use is not feasible because of one of the six factors in this paragraph. If a State adopts a new or revised water quality standard based on a required use attainability analysis, the State shall also adopt the highest attainable use, as defined in § 131.3(m).

* * * * *

(j) A State must conduct a use attainability analysis as described in § 131.3(g), and paragraph (g) of this section, whenever:

(1) The State designates for the first time, or has previously designated for a water body, uses that do not include the uses specified in section 101(a)(2) of the Act; or

(2) The State wishes to remove a designated use that is specified in section 101(a)(2) of the Act, to remove a sub-category of such a use, or to designate a sub-category of such a use that requires criteria less stringent than previously applicable.

(k) A State is not required to conduct a use attainability analysis whenever:

(1) The State designates for the first time, or has previously designated for a water body, uses that include the uses specified in section 101(a)(2) of the Act; or

(2) The State designates a sub-category of a use specified in section 101(a)(2) of the Act that requires criteria at least as stringent as previously applicable; or

(3) The State wishes to remove or revise a designated use that is a non-101(a)(2) use. In this instance, as required by paragraph (a) of this section, the State must submit documentation justifying how its consideration of the use and value of water for those uses listed in paragraph (a) appropriately supports the State's action, which may be satisfied through a use attainability analysis.

■ 6. In § 131.11, revise paragraphs (a)(2) and (b) introductory text to read as follows:

§ 131.11 Criteria.

(a) * * *

(2) *Toxic pollutants.* States must review water quality data and information on discharges to identify specific water bodies where toxic pollutants may be adversely affecting water quality or the attainment of the designated water use or where the levels of toxic pollutants are at a level to warrant concern and must adopt criteria for such toxic pollutants applicable to the water body sufficient to protect the designated use. Where a State adopts narrative criteria for toxic pollutants to protect designated uses, the State must provide information identifying the method by which the State intends to regulate point source discharges of toxic pollutants on water quality limited segments based on such narrative criteria. Such information may be included as part of the standards or may be included in documents generated by the State in response to the Water

Quality Planning and Management Regulations (40 CFR part 130).

(b) *Form of criteria:* In establishing criteria, States should:

* * * * *

■ 7. In § 131.12:

■ a. Revise the section heading and paragraphs (a) introductory text and (a)(2).

■ b. Add paragraph (b).

The revisions and additions read as follows:

§ 131.12 Antidegradation policy and implementation methods.

(a) The State shall develop and adopt a statewide antidegradation policy. The antidegradation policy shall, at a minimum, be consistent with the following:

* * * * *

(2) Where the quality of the waters exceeds levels necessary to support the protection and propagation of fish, shellfish, and wildlife and recreation in and on the water, that quality shall be maintained and protected unless the State finds, after full satisfaction of the intergovernmental coordination and public participation provisions of the State's continuing planning process, that allowing lower water quality is necessary to accommodate important economic or social development in the area in which the waters are located. In allowing such degradation or lower water quality, the State shall assure water quality adequate to protect existing uses fully. Further, the State shall assure that there shall be achieved the highest statutory and regulatory requirements for all new and existing point sources and all cost-effective and reasonable best management practices for nonpoint source control.

(i) The State may identify waters for the protections described in paragraph (a)(2) of this section on a parameter-by-parameter basis or on a water body-by-water body basis. Where the State identifies waters for antidegradation protection on a water body-by-water body basis, the State shall provide an opportunity for public involvement in any decisions about whether the protections described in paragraph (a)(2) of this section will be afforded to a water body, and the factors considered when making those decisions. Further, the State shall not exclude a water body from the protections described in paragraph (a)(2) of this section solely because water quality does not exceed levels necessary to support all of the uses specified in section 101(a)(2) of the Act.

(ii) Before allowing any lowering of high water quality, pursuant to paragraph (a)(2) of this section, the State shall find, after an analysis of alternatives, that such a lowering is necessary to accommodate important economic or social development in the area in which the waters are located. The analysis of alternatives shall evaluate a range of practicable alternatives that would prevent or lessen the degradation associated with the proposed activity. When the analysis of alternatives identifies one or more practicable alternatives, the State shall only find that a lowering is necessary if one such alternative is selected for implementation.

* * * * *

(b) The State shall develop methods for implementing the antidegradation policy that are, at a minimum, consistent with the State's policy and with paragraph (a) of this section. The State shall provide an opportunity for public involvement during the development and any subsequent revisions of the implementation methods, and shall make the methods available to the public.

■ 8. Add § 131.14 to read as follows:

§ 131.14 Water quality standards variances.

States may adopt WQS variances, as defined in § 131.3(o). Such a WQS variance is subject to the provisions of this section and public participation requirements at § 131.20(b). A WQS variance is a water quality standard subject to EPA review and approval or disapproval.

(a) *Applicability.* (1) A WQS variance may be adopted for a permittee(s) or water body/waterbody segment(s), but only applies to the permittee(s) or water body/waterbody segment(s) specified in the WQS variance.

(2) Where a State adopts a WQS variance, the State must retain, in its standards, the underlying designated use and criterion addressed by the WQS variance, unless the State adopts and EPA approves a revision to the underlying designated use and criterion consistent with §§ 131.10 and 131.11. All other applicable standards not specifically addressed by the WQS variance remain applicable.

(3) A WQS variance, once adopted by the State and approved by EPA, shall be the applicable standard for purposes of the Act under § 131.21(d) through (e), for the following limited purposes. An approved WQS variance applies for the purposes of developing NPDES permit limits and requirements under 301(b)(1)(C), where appropriate, consistent with paragraph (a)(1) of this section. States and other certifying entities may also use an approved WQS variance when issuing certifications under section 401 of the Act.

(4) A State may not adopt WQS variances if the designated use and criterion addressed by the WQS variance can be achieved by implementing technology-based effluent limits required under sections 301(b) and 306 of the Act.

(b) *Requirements for Submission to EPA.* (1) A WQS variance must include:

(i) Identification of the pollutant(s) or water quality parameter(s), and the water body/waterbody segment(s) to which the WQS variance applies. Discharger(s)-specific WQS variances must also identify the permittee(s) subject to the WQS variance.

(ii) The requirements that apply throughout the term of the WQS variance. The requirements shall represent the highest attainable condition of the water body or waterbody segment applicable throughout the term of the WQS variance based on the documentation required in (b)(2) of this section. The requirements shall not result in any lowering of the currently attained ambient water quality, unless a WQS variance is necessary for restoration activities, consistent with paragraph (b)(2)(i)(A)(*2*) of this section. The State must specify the highest attainable condition of the water body or waterbody segment as a quantifiable expression that is one of the following:

(A) For discharger(s)-specific WQS variances:

(*1*) The highest attainable interim criterion; or

(*2*) The interim effluent condition that reflects the greatest pollutant reduction achievable; or

(*3*) If no additional feasible pollutant control technology can be identified, the interim criterion or interim effluent condition that reflects the greatest pollutant reduction achievable with the pollutant control technologies installed at the time the State adopts the WQS variance, and the adoption and implementation of a Pollutant Minimization Program.

(B) For WQS variances applicable to a water body or waterbody segment:

(*1*) The highest attainable interim use and interim criterion; or

(*2*) If no additional feasible pollutant control technology can be identified, the interim use and interim criterion that reflect the greatest pollutant reduction achievable with the pollutant control technologies installed at the time the State adopts the WQS variance, and the adoption and implementation of a Pollutant Minimization Program.

(iii) A statement providing that the requirements of the WQS variance are either the highest attainable condition identified at the time of the adoption of the WQS variance, or the highest attainable condition later identified during any reevaluation consistent with paragraph (b)(1)(v) of this section, whichever is more stringent.

(iv) The term of the WQS variance, expressed as an interval of time from the date of EPA approval or a specific date. The term of the WQS variance must only be as long as necessary to achieve the highest attainable condition and consistent with the demonstration provided in paragraph (b)(2) of this section. The State may adopt a subsequent WQS variance consistent with this section.

(v) For a WQS variance with a term greater than five years, a specified frequency to reevaluate the highest attainable condition using all existing and readily available information and a provision specifying how the State intends to obtain public input on the reevaluation. Such reevaluations must occur no less frequently than every five years after EPA approval of the WQS variance and the results of such reevaluation must be submitted to EPA within 30 days of completion of the reevaluation.

(vi) A provision that the WQS variance will no longer be the applicable water quality standard for purposes of the Act if the State does not conduct a reevaluation consistent with the frequency specified in the WQS variance or the results are not submitted to EPA as required by (b)(1)(v) of this section.

(2) The supporting documentation must include:

(i) Documentation demonstrating the need for a WQS variance.

(A) For a WQS variance to a use specified in section 101(a)(2) of the Act or a sub-category of such a use, the State must demonstrate that attaining the designated use and criterion is not feasible throughout the term of the WQS variance because:

(*1*) One of the factors listed in § 131.10(g) is met, or

(*2*) Actions necessary to facilitate lake, wetland, or stream restoration through dam removal or other significant reconfiguration activities preclude attainment of the designated use and criterion while the actions are being implemented.

(B) For a WQS variance to a non-101(a)(2) use, the State must submit documentation justifying how its consideration of the use and value of the water for those uses listed in § 131.10(a) appropriately supports the WQS variance and term. A demonstration consistent with paragraph (b)(2)(i)(A) of this section may be used to satisfy this requirement.

(ii) Documentation demonstrating that the term of the WQS variance is only as long as necessary to achieve the highest attainable condition. Such documentation must justify the term of the WQS variance by describing the pollutant control activities to achieve the highest attainable condition, including those activities identified through a Pollutant Minimization Program, which serve as milestones for the WQS variance.

(iii) In addition to paragraphs (b)(2)(i) and (ii) of this section, for a WQS variance that applies to a water body or waterbody segment:

(A) Identification and documentation of any cost-effective and reasonable best management practices for nonpoint source controls related to the pollutant(s) or water quality parameter(s) and water body or waterbody segment(s) specified in the WQS variance that could be implemented to make progress towards attaining the underlying designated use and criterion. A State must provide public notice and comment for any such documentation.

(B) Any subsequent WQS variance for a water body or waterbody segment must include documentation of whether and to what extent best management practices for nonpoint source controls were implemented to address the pollutant(s) or water quality parameter(s) subject to the WQS variance and the water quality progress achieved.

(c) *Implementing WQS variances in NPDES permits.* A WQS variance serves as the applicable water quality standard for implementing NPDES permitting requirements pursuant to § 122.44(d) of this chapter for the term of the WQS variance. Any limitations and requirements necessary to implement the WQS variance shall be included as enforceable conditions of the NPDES permit for the permittee(s) subject to the WQS variance.

■ 9. Add § 131.15 to read as follows:

§ 131.15 Authorizing the use of schedules of compliance for water quality-based effluent limits in NPDES permits.

If a State intends to authorize the use of schedules of compliance for water quality-based effluent limits in NPDES permits, the State must adopt a permit compliance schedule authorizing provision. Such authorizing provision is a water quality standard subject to EPA review and approval under section 303 of the Act and must be consistent with sections 502(17) and 301(b)(1)(C) of the Act.

Subpart C—Procedures for Review and Revision of Water Quality Standards

■ 10. In § 131.20, revise paragraphs (a) and (b) to read as follows:

§ 131.20 State review and revision of water quality standards.

(a) *State review.* The State shall from time to time, but at least once every 3 years, hold public hearings for the purpose of reviewing applicable water quality standards adopted pursuant to §§ 131.10 through 131.15 and Federally promulgated water quality standards and, as appropriate, modifying and adopting standards. The State shall also re-examine any waterbody segment with water quality standards that do not include the uses specified in section 101(a)(2) of the Act every 3 years to determine if any new information has become available. If such new information indicates that the uses specified in section 101(a)(2) of the Act are attainable, the State shall revise its standards accordingly. Procedures States establish for identifying and reviewing water bodies for review should be incorporated into their Continuing Planning Process. In addition, if a State does not adopt new or revised criteria for parameters for which EPA has published new or updated CWA section 304(a) criteria recommendations, then the State shall provide an explanation when it submits the results of its triennial review to the Regional Administrator consistent with CWA section 303(c)(1) and the requirements of paragraph (c) of this section.

(b) *Public participation.* The State shall hold one or more public hearings for the purpose of reviewing water quality standards as well as when revising water quality standards, in accordance with provisions of State law and EPA's public participation regulation (40 CFR part 25). The proposed water quality standards revision and supporting analyses shall be made available to the public prior to the hearing.

* * * * *

■ 11. In § 131.22, revise paragraph (b) to read as follows:

§ 131.22 EPA promulgation of water quality standards.

* * * * *

(b) The Administrator may also propose and promulgate a regulation, applicable to one or more navigable waters, setting forth a new or revised standard upon determining such a standard is necessary to meet the requirements of the Act. To constitute an Administrator's determination that a new or revised standard is necessary to meet the requirements of the Act, such determination must:

(1) Be signed by the Administrator or his or her duly authorized delegate, and

(2) Contain a statement that the document constitutes an Administrator's determination under section 303(c)(4)(B) of the Act.

* * * * *

Subpart D—Federally Promulgated Water Quality Standards

■ 12. In § 131.34, revise paragraph (c) to read as follows:

§ 131.34 Kansas.

* * * * *

(c) *Water quality standard variances.* The Regional Administrator, EPA Region 7, is authorized to grant variances from the water quality standards in paragraphs (a) and (b) of this section where the requirements of § 131.14 are met.

■ 13. In § 131.40, revise paragraph (c) to read as follows:

§ 131.40 Puerto Rico.

* * * * *

(c) *Water quality standard variances.* The Regional Administrator, EPA Region 2, is authorized to grant variances from the water quality standards in paragraphs (a) and (b) of this section where the requirements of § 131.14 are met.

[FR Doc. 2015–19821 Filed 8–20–15; 8:45 am]

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November 15, 2010

VIA ELECTRONIC SUBMISSION & U.S. MAIL

Hazardous Waste Management System
Identification and Listing of Special Wastes
Disposal of Coal Combustion Residuals from Electric Utilities Docket
Attention Docket ID No. EPA-HQ-RCRA-2009-0640
Environmental Protection Agency
Mailcode 5305T
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

Dear Administrator Jackson:

American Electric Power (AEP) submits these comments on USEPA's proposed Coal Combustion Residuals (CCR) rule for its wholly owned subsidiaries AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company

AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network covering a 197,500 square mile service territory supplying power to over 5.2 million customers. AEP operations and our customers' electric rates will be directly affected by any changes to the regulations addressing CCRs.

AEP's comments on the CCR rule follow. Please address any questions on these comments to Thomas E. Webb, P.E., Director, Land Environment & Remediation Services at tewebb@aep.com, or 614-716-1266.

Sincerely yours,

John M. McManus

John M. McManus, P.E.
Vice President, Environmental Services

PENGAD 800-631-6989
EXHIBIT
SC-8

cc: Mr. Mathy Stanislaus, Assistant Administrator, OSWER
Ms. Suzanne Rudzinski, Acting Director, ORCR
Mr. Thomas Webb, AEP

Comments on the Proposed CCR Rule by American Electric Power (AEP)

AEP appreciates the opportunity to comment on USEPA's proposed coal combustion residuals rule published in the *Federal Register* on June 21, 2010. The comments that follow are submitted under seven discrete headings. In addition to these comments, AEP endorses the comments made by the Utility Solid Waste Activities Group (USWAG) and by the Electric Power Research Institute (EPRI).

I. AEP strongly recommends that USEPA adopt a regulatory program under the D Prime option. AEP also strongly believes that an approach under Subtitle C is completely unwarranted.

AEP recommends that USEPA adopt the D Prime option, which would allow continued use of ash ponds meeting performance standards, and is a reasonable and environmentally protective standard to which to hold the electric power industry. USWAG has estimated the incremental, direct costs of a Subtitle D program and it is substantial, amounting to about $29 billion for compliance across the United States. In AEP's experience that equates to about $43 billion expressed as a fully loaded cost. Looking at AEP alone, the fully loaded compliance cost for the AEP operated coal-fired power plants that would continue to operate after 2017 has been estimated (a pre-screening analysis) by AEP engineers at $3.9 billion. That estimate assumes wet-to-dry conversions for fly ash and bottom ash, closure of existing ash ponds, building replacement wastewater treatment processes and five years of landfill volume. Any compliance program for CCRs more onerous than a Subtitle D program would only increase the cost of compliance, probably by about a factor of two, based on an analysis performed by EPRI. We believe that the fully loaded cost estimate of about $3.9 billion for AEP's compliance with a Subtitle D rule equates to a fully loaded cost estimate of about $7.8 billion under a Subtitle C rule. The costs are extreme, especially when compared to limited additional protection of human health and the environment.

Compliance costs will be paid by the customers. AEP evaluated the impact that even a Subtitle D rule would have on ratepayers' bills in the various AEP operating companies. Calculations showed that the incremental rate increases associated with complying with CCR regulations under the proposed Subtitle D program would be.

- Kentucky Power Company: +2.2%
- Ohio Power Company: +8.3%
- Columbus Southern Ohio Electric Company: +1.3%
- Indiana Michigan Electric Company: +0.3%
- Appalachian Power Company: +6.8%
- Southwestern Electric Power Company: +6.2%
- Public Service Company of Oklahoma: +1.6%

These rate increases are substantial in a number of the jurisdictions that we serve and would be in addition to rate impacts that are occurring and expected to occur as a result of other USEPA regulatory programs. And these increases come at a time in which the states AEP operates in and the customers we serve are struggling with a very difficult economy. While AEP is supportive of reasonable requirements that truly provide environmental and public health benefits, we cannot afford regulations that are overly stringent and provide little or no benefits.

AEP believes that a hazardous waste designation for CCRs makes no sense from a technical perspective, and is not needed to achieve the environmental protection goals of this program. AEP's CCRs pass the TCLP test used to determine hazardous waste classification by characteristic. To place the added burden and cost of a RCRA Subtitle C program on a waste that does not present the kinds of risks associated with a hazardous waste is not warranted. A hazardous waste classification will deter beneficial use of coal combustion products (CCPs) that now have value and that contribute in a positive environmental manner.

AEP notes that many states have gone on record expressing their preference for a solid waste program, and their desire to continue to be involved in administering CCR solid waste disposal programs. AEP agrees that states are in the best position to decide disposal questions and to evaluate beneficial use scenarios. A one-size-fits-all program on a national platform does not take into account the varied geography, meteorology, hydrology and geology of the United States. There are physical differences that need to be taken into account by the regulating agency when setting design standards and performance standards. As an example, to require a composite liner to have 2 ft of <1 x 10-7 cm/sec clay does not take into account the equivalency calculation that can show the same protection but with a different product. Such a demonstration of equivalency should be allowed by USEPA in any final regulation that is promulgated. A rigid design standard for the whole country is not defensible.

AEP notes that EPRI has done excellent work in estimating the cost of CCR rule compliance nationally, under a hazardous waste program. EPRI also has studied and commented on the USEPA risk assessment's shortcomings, the damage cases in general, the new leaching protocol (LEAF), the value of using FGD gypsum in agriculture, the value of responsibly engineered structural fills using CCR, and disposal site designs. AEP supports all of the statements made by EPRI and is in full agreement with the EPRI positions.

AEP also notes that three Congressional letters were sent to USEPA Administrator Jackson at the end of July 2010 strongly opposing the Subtitle C option, including (1) a bi-partisan letter from 124 Representatives, led by Congressman Holden; (2) a bi-partisan letter from 35 Senators, led by Senators Conrad and Brownback, and; (3) a bi-partisan letter from a majority of the members on the House Energy and Commerce Committee, led by Representatives Boucher and Upton. All told, in the 111th Congress, 42 Senators have gone on record opposing the Subtitle C option and 165

Representatives have gone on record opposing the Subtitle C option. AEP respectfully urges USEPA to listen to and act on the urgings of USWAG, EPRI and members of Congress who have made statements about the inadvisability of a Subtitle C decision for CCRs.

II. The structural integrity of ash dams and landfills must be ensured.

AEP concurs with USEPA's proposal to incorporate surface impoundment integrity, inspection, and reporting requirements into the RCRA program modeled largely on the standards for coal slurry impoundments regulated by the Mine Safety and Health Administration ("MSHA") (at 30 C.F.R. § 77.216). While the MSHA standards regulate a broader array of materials with differing physical properties than CCRs, the MSHA rules provide a good starting point for developing comparable standards for CCR impoundments. These requirements will establish a uniform program throughout the country.

There are over 10,000 "High Hazard Potential" dams across the country operated by governmental agencies and private industries. Based on the utility responses to USEPA's information collection request, USEPA has released a list of utility ash handling dams along with their hazard ranking. According to that list, there are 49 utility ash handling dams rated as "High Hazard Potential" and 60 rated as "Significant Hazard Potential." All others are rated either "Low Hazard Potential" or "No Hazard Potential." On that list, AEP has 11 "High Hazard Potential" dams, eight "Significant Hazard Potential" dams, 11 "Low Hazard Potential" dams, and 13 "No Hazard Potential" dams. So, AEP operations will be significantly affected by these rules.

The four classification levels are defined below listed in decreasing order of potential hazards:

1. High Hazard Potential – those dams whose failure will likely cause loss of human life
2. Significant Hazard Potential – those dams whose failure will not result in loss of human life but will cause economic loss, environmental damage, and/or disruption of lifeline facilities off-site
3. Low Hazard Potential – those dams whose failure will not result in loss of human life or off-site damages but only damage limited to the owner's property
4. No Hazard Potential – those dams whose failure will not result in any loss of human life, any off-site damage, or any significant on-site damage

USEPA's proposed rules subject all surface impoundments to the dam structural integrity requirements regardless of the potential hazard class. AEP believes that only those dams that are classified as "High Hazard Potential" and "Significant Hazard Potential" should be subject to the dam structural integrity requirements. Only those two hazard classes pose a threat to human health or the environment. The other two classes present only minimal impacts limited to on-site areas or present no adverse impacts at all associated with a failure. This would be consistent with many state dam regulatory programs that apply standards only to those dams with a high or significant hazard potential.

Also, EPA's proposed rule for requiring weekly monitoring of instrumentation is excessive and overly stringent. AEP suggests that monthly instrumentation monitoring be required for High Hazard Potential dams and quarterly for Significant Hazard Potential dams.

III. The benefits of Coal Combustion Product (CCP) utilization are well documented and beneficial use of CCPs should be encouraged, not discouraged.

Since 1989 American Electric Power has beneficially used 43 million tons of fly ash, bottom ash and boiler slag, resulting in $94 million in revenue and $186 million in avoided disposal costs, all of which reduces the cost of electricity to our customers. Using 43 million tons of CCPs in concrete, structural fill, engineered stabilization, blasting grit, roofing shingles and winter road hazard control means that 43 million tons of naturally occurring materials did not have to be mined and processed. Environmental impacts associated with mining replacement minerals were avoided for the tons of CCPs utilized.

The 10 million tons of AEP fly ash used as a concrete add-mixture since 1989 reduced the amount of carbon dioxide emitted into the atmosphere by a roughly equal amount of 10 million tons. The entire CCP beneficial use industry has reduced CO_2 emissions by about one billion tons in the past decade. In addition, fly ash utilized in concrete improves the quality of that material. Fly ash can be used as a direct replacement for Portland cement in concrete and has been used in a wide variety of concrete applications in the United States for more than 60 years. The use of fly ash in concrete can improve strength, permeability and resistance to alkali silicate reactivity. There is a standard ASTM specification that establishes the physical and chemical requirements of fly ash for use in concrete. AEP believes that any move by USEPA to classify fly ash as a Special Waste under the hazardous waste Subtitle C program would have an adverse effect on the important utilization of fly ash in concrete, notwithstanding USEPA's statement that they are in favor of encapsulated uses of CCPs.

Boiler Slag which is used as a high-grade low-cost blasting grit can eliminate the use of sand for blasting. Sand contains silica and carries with it the potential health risk of silicosis. Boiler Slag also is used as a roofing shingle granule because of its low cost and glassy translucent properties and durability.

Bottom ash is used as a low-cost engineered fill material that is stable. Bottom ash also is used as winter road hazard control for improved traction, in place of salt and gravel and sand. Bottom ash usually costs less than competing materials and this cost savings is important to the many villages, townships and counties who rely on bottom ash for snow and ice control.

Since 2007 AEP has supplied 1.2 million tons of synthetic gypsum to the wallboard manufacturing market. Synthetic gypsum production drastically reduces the need for mined natural gypsum. Mined gypsum has to be processed to wallboard grade which adds to the cost of the final consumer product. Based on 280 wallboard sheets per average US home, AEP has supplied enough synthetic gypsum to result in wallboard installation in over 170,000 homes.

In the recent past, AEP has had to respond to concern from CCP marketers, commercial CCP users and government entities regarding the potential for a hazardous waste designation for CCRs. The concept of dual CCP handling instructions for the same ash, i.e., non-hazardous when used beneficially as compared to a hazardous waste designation when disposed of, concerns everyone who handles CCPs. We live in a litigious society and the expectation is that unfounded toxic tort suits will erode the will of those currently using CCPs beneficially to the point where the expedient thing to do is to stop utilization. A RCRA Subtitle C designation would result in an unnecessary loss of beneficial use applications, which will result in increased prices in the ash and electric generation industry. Those costs will be passed on to the consumer.

IV. If USEPA goes ahead with required phase-out of ash ponds, the compliance schedule must be practicable.

The Subtitle D option would require that existing surface impoundments that cannot demonstrate that the impoundment is constructed in a stable area must close within five years after the effective date of the rule with an extension of two years if it can be demonstrated that there is no available alternative disposal capacity and there is no immediate threat to human health and the environment (Proposed Rule 257.65). Further, under Subtitle D, those impoundments that are located in a stable area would be required to be dredged and have installed a composite liner and leachate collection system within five years or be closed [Proposed Rule 257.71 (g)] with apparently no extension available. Then, proposed rule 257.100 (j)&(k) would require that closure activities begin within 30 days after the date on which the surface impoundment receives the final receipt of CCRs and that closure be completed within 180 days following the beginning of closure (210 days total to complete closure). It should be pointed out that at some locations, it will take at least four years from the time the new CCR rule becomes effective to accomplish the wet-to-dry conversion and to accomplish the switch to dry, which means that wet ashes would be received as late as the end of Year 4.

The Subtitle C option would require that surface impoundments cease receiving CCRs within five years of the date of rule promulgation and complete closure within two years after placement of waste in the surface impoundment ceases.

These closure timelines will be impossible to meet in certain situations. For example, in order to cease the use of surface impoundments, the generating units first need to be converted to dry ash handling and a landfill constructed This schedule will be severely impacted by the equipment manufacturers and labor force needed to manufacture and construct the required wet-to-dry conversions for the entire electric utility industry. Also, it can take four to six years to site, design, permit, and construct a landfill. That time frame could be even longer if the landfill permitting encounters public opposition or has to be permitted as a hazardous waste landfill. Indeed, public opposition to a hazardous waste landfill could make it impossible to even get a landfill permit

Not only is the five to seven year total closure time frame troublesome, the requirement to close a surface impoundment within 210 days of the cessation of CCR disposal (Subtitle D) or within two years of cessation of CCR disposal (Subtitle C) will be impossible in many situations. Closure may be accomplished either through CCR removal and decontamination of all affected areas or by closure leaving the CCRs in place. For large surface impoundments, it is not practicable to accomplish closure through CCR removal. To close with the CCRs in place, free liquids must be removed, the remaining CCRs must be stabilized to a bearing capacity sufficient to support the final cover without settlement concerns, and the final cover placed.

It is not uncommon for AEP ash impoundments to have surface areas of 100 to 300 acres and a length of 5,000 feet or more. It can take several years to remove liquids and stabilize a surface impoundment to the point where a final cover can be placed without settlement concerns. Such procedures could include the installation of wick drains for liquid removal and/ or the preloading of the ash with 20 to 100 ft of soil/rock material over several years to properly consolidate the area for final cover placement. The cost to dewater such large areas is estimated at about $100,000 per acre. The cover system must consist of a 1.5 foot clay layer and 6 inches of topsoil and be sloped a minimum of 2% to 5% for positive surface drainage. To construct a cover system that provides positive drainage over such large surface areas would require, in some cases, 8-10 million cubic yards of fill. Based on a production rate of 10,000 cubic yards of fill per day, it would take 800 working days to construct the fill With earthwork construction limited to about seven months per year, it could take four to five years to complete the fill. Additionally, the production of millions of cubic yards of such fill from natural sources is not without its own environmental impacts. So, to require surface impoundments to close within 210 days (Subtitle D), or even two years (Subtitle C), from the date of receipt of the final CCRs is simply not possible for large impoundments.

Another issue to take note of is that, because these rules will require that a large number of utility surface impoundments be closed nationwide during roughly the same time frame, utilities will have difficulty obtaining the personnel and equipment necessary to close multiple sites, especially since other companies will need to obtain the same resources at the same time.

Furthermore, due to the significant volume of clay that is needed to cover an impoundment hundreds of acres in size and the likelihood that other units may need to close in the same time frame, there may be insufficient supply of ready-to-use clay. The proposed rules do not allow for any alternative liners, so selected clay must be used if the final rule does not change. Moreover, in some circumstances, states may not be able to provide final approval of a facility's closure plan before the end of the closure time limits, putting facilities in automatic non-compliance through no fault of their own, but due simply to limited state resources.

USEPA acknowledges in the preamble that its closure time frames were borrowed directly from the existing closure time frames for municipal solid waste landfills (MSWFLs) under 40 CFR, Part 258. While application of the MSWLFs standards to CCR surface impoundments is appropriate in many respects, this is certainly not one of those instances. AEP surface impoundments are often much larger than MSWLFs, and MSWLFs obviously do not contain the volume of water contained in ash impoundments. Furthermore, landfills typically close each disposal cell when it reaches its disposal capacity so that many cells have already been "closed" when the landfill begins final closure. Surface impoundments, on the other hand, must be entirely dewatered and stabilized before closure can begin for any portion of the impoundment. While USEPA's proposed closure timeframe may be appropriate for some landfill types, it is entirely unreasonable and unjustifiable from a technical perspective to apply this same time frame to surface impoundments.

Given the disparity in the sizes of surface impoundments, the length of time necessary to dewater, stabilize the area, and place the final cover over the impoundment, AEP strongly recommends that if USEPA ends up requiring closure that USEPA not establish a specific time frame for closure. Instead, we urge USEPA to require utilities that have to close any CCR surface impoundments do so consistent with a closure plan approved by a state, with a schedule that the state finds acceptable. Establishment of a closure plan, with set schedules, is the most effective method to account for the many variables associated with the closure of these units and is the approach commonly used by utilities. A closure plan also will provide USEPA and the public with certainty that closure will occur in a step-wise and timely manner, without requiring facilities to comply with wholly unrealistic closure time schedules.

V. USEPA should recognize that CCRs are not all the same.

There are fundamental differences among the different CCRs. Boiler slag is quite different from fly ash and fly ash is quite different from FGD gypsum. To group boiler slag, bottom ash, fly ash, cenospheres, fixated FGD byproduct and FGD gypsum all together and characterize them all in the same way is in error. It is incorrect for USEPA to view wastes as a single class, where a group of six distinct types of wastes have different physical and chemical properties, are produced in different volumes, and are managed differently. USEPA should view each individual waste and evaluate each waste against the ten listing critieria, rather than lumping them all together. They are different and behave differently in the environment.

EPRI's recently published report entitled *Comparisons of Risks for Leachate from Coal Combustion Product Landfills and Impoundments with Risks for Leachate from Municipal Solid Waste Landfill Facilities* (November 2010) provides risk-based analyses. EPRI concluded that "[B]ased on this risk-based comparison, it can be concluded that the relative human health risks associated with leachates from MSW landfills and fly ash management are similar." EPRI further concluded that on an ecological risk basis that the MSW leachate results were 190-fold to 1,700-fold, depending on the parameter, higher than the CCP leachate results. So even fly ash, which generally is the CCP that leaches higher concentrations of elements of concern than the other CCPs, is no worse than MSW landfill leachate from a human health perspective, and better than MSW landfill leachate from an ecological perspective That bit of research is further confirmation that even the most leachable of the CCPs does not warrant regulation as a RCRA hazardous waste under a Special Waste classification. If fly ash does not warrant a Subtitle C classification, then certainly boiler slag, bottom ash, fixated FGD byproduct and FGD gypsum do not either.

VI. AEP's two "Proven" damage cases and one "Potential" damage case should be removed from USEPA's July 9, 2007 list of 27 Proven and 40 Potential damage cases.

Since CCRs do not meet any of the four characteristics of hazardous waste – ignitability, corrosivity, reactivity, or TCLP Toxicity, USEPA uses a list of damage cases as the primary justification for listing CCRs as hazardous waste Therefore, it is of utmost importance that these damage cases receive thorough review based on sound science to determine whether these cases are truly "damage cases."

AEP has two cases on the list of USEPA's "proven" damage cases – Welsh reservoir and Brandy Branch reservoir – and one case on the "potential" damage case list – the Conesville Fixed FGD Sludge landfill in Ohio. None of these three cases should be included on USEPA's damage case list.

The Welsh reservoir serves the Welsh electric generating plant and is a 1,465 acre cooling pond constructed in 1976. The pond originally received effluent from ash impoundments prior to 2000. The ash handling procedures were then modified to eliminate the discharge of decant water to the cooling reservoir. A consumption advisory for fish caught in the cooling pond was issued in 1992 stating that selenium concentrations in fish tissue exceeded a level of 2 mg/kg which was used, at that time, as the "standard." The derivation of this "standard" was questionable. A more scientific risk study prepared by the Texas Department of Health (TDH) entitled "Quantitative Risk Characterization, Welsh Reservoir, Titus County, Texas" dated September 29, 2003 established a health-based assessment comparison (HAC) for fish tissue residue concentration (TRC) of 6 mg selenium/kg of fish tissue. For all samples collected over 17 years, the mean selenium fish tissue concentration was 3.6 mg/kg with only one sample exceeding the 6 mg/kg TRC. Based on these data, the TDH concluded that the amount of selenium ingested from expected meal quantities is equivalent to unlimited consumption of fish from this reservoir. The selenium fish consumption advisory subsequently was lifted by the TDH on October 14, 2003. Based on the above discussion, this case should have never been listed as a proven damage case and should be removed from USEPA's list.

A situation virtually identical to that of the Welsh reservoir is the Brandy Branch reservoir. This reservoir was built in 1983 and is a 1,257 acre cooling pond serving the Pirkey electric generating plant. Initially, coal pile runoff was discharged into the reservoir but was subsequently diverted to the flue gas desulfurization system. A fish consumption advisory was issued for the Brandy Branch reservoir in 1992 in conjunction with the advisory issued for the Welsh reservoir. Like Welsh, the advisory was based on the questionable "standard" of 2 mg/kg of fish tissue and, like Welsh, a more scientific risk study prepared by the Texas Department of Health (TDH) entitled "Quantitative Risk Characterization, Brandy Branch Reservoir, Harrison County, Texas" dated September 29, 2003 established a health-based assessment comparison (HAC) for fish tissue residue concentration (TRC) of 6 mg selenium/kg of fish tissue. The mean selenium concentration for fish tissue in samples collected from the Brandy Branch reservoir over 17 years was 2.23 mg/kg. The highest mean never exceeded the TRC. The TDH again concluded that the amount of selenium ingested from expected meal quantities is equivalent to unlimited consumption of fish from the Brandy Branch reservoir. The 1992 fish consumption advisory was lifted by TDH on October 14, 2003 based on the more accurate and scientific risk characterization described above. Based on the above facts, this case should have never been listed as a proven damage case and it too should be removed from USEPA's damage case list

The Conesville Fixed FGD Sludge landfill was constructed in 1976 and covered about 50 acres. It was closed, capped, and seeded in 1988, almost 23 years ago. Groundwater monitoring data from 34 groundwater monitoring wells around this facility when it was active had been analyzed by USEPA pursuant to the 1988 Report to Congress. From analyzing two sets of groundwater data, USEPA identified exceedances of Primary Drinking Water Standards (PDWS) for arsenic, cadmium, selenium, and chromium. USEPA stated that the selenium exceedances were due to upgradient sources. Arsenic and cadmium were present in on-site wells only. Lead and chromium were the only metals that exceeded the PDWS in off-site wells. Shortly thereafter, the filtrate from the FGD sludge stabilization process, believed to be a possible source of cadmium, was routed to the thickener tanks. Subsequently, groundwater monitoring was performed for an additional six years. Results indicated that only one of 482 samples for arsenic exceeded the PDWS. Only six of 520 samples exceeded the PDWS for chromium, and five of the six exceedances occurred on one of the 25 sampling events. Seventeen of 582 samples exceeded the PDWS for lead, and all of those exceedances occurred on three of the 25 sampling events. No samples exceeded the cadmium PDWS. Based on the above data, along with USEPA's statement that there is limited potential for off-site migration of contaminants (and the fact that this landfill has been closed and capped for almost 23 years) this site should be removed from USEPA's list of potential damage cases.

VII. USEPA should use only proven damage cases when judging whether a Subtitle D or a Subtitle C rule is warranted.

AEP believes that there are eight statutorily-required study factors that USEPA has to evaluate when determining whether CCRs warrant regulation under Subtitle C of RCRA. One of those is the need for USEPA to find "documented cases in which danger to human health or the environment from surface runoff or leachate has been proved" (RCRA Section 8002(n)(4)). "Proven" damage cases, according to 75 Fed. Reg. at 35131, "means those cases with (1) Documented exceedances of primary maximum contaminant levels (MCLs) or other health-based standards measured in ground water at sufficient distance from the waste management unit to indicate that hazardous constituents have migrated to the extent that they could cause human health concerns, and/or (2) where a scientific study provides documented evidence of another type of damage to human health or the environment (*e.g.*, ecological damage), and/or (3) where there has been an administrative ruling or court decision with an explicit finding of specific damage to human health or the environment."

AEP notes that the two reports issued in 2010 by environmental activist groups on February 24th and on August 26th listed additional sites that they believed rose to the level of damage cases. However, it is not appropriate for USEPA to include *potential* damage cases in its evaluation of the right regulatory classification for CCRs going forward. Alleged damage cases presented by environmental activist groups are not proven and cannot be relied upon by USEPA in this rulemaking.

The Bevill Amendment was clear in that only cases where such danger "has been proved" were to be included (RCRA Section 8002(n)(4)). It is necessary that USEPA, to the extent that the Agency considers damage cases in this proceeding, only use cases that meet the statutory criteria of documented, proven damage when deciding whether a reversal of its final 2000 Regulatory Determination is appropriate. AEP believes that such a reversal would not be appropriate. CCR rules written under Subtitle D of RCRA can fully address USEPA's concerns with any sites that meet USEPA's criteria for required remediation. There is no reason to go to Subtitle C, and D Prime is the appropriate regulatory approach.

SC
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Water Docket
U.S. Environmental Protection Agency
Mail Code: 4203M
1200 Pennsylvania Avenue
Washington, D.C. 20460

Attention Docket ID No. EPA-HQ-OW-2008-0667

August 18, 2011

Comments of American Electric Power, Inc. on Proposed Rule for Cooling Water Intake Structures at Existing Facilities - Docket No. EPA-HQ-OW-2008-0667

Dear Sir or Madam:

American Electric Power is pleased to offer the enclosed comments on EPA's proposed rule to regulate cooling water intake structures at existing facilities and Phase I facilities, published at 76 Fed. Reg. 22,174 (April 20, 2011). American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas).

We agree with EPA's proposal to have State permit writers develop NPDES permit requirements for entrainment mortality, where needed, on a case-by-case basis, taking into account costs and benefits and impacts on energy supply and reliability. However, we believe that EPA needs to take this one step farther by allowing State permitting agencies to set cooling water intake structure requirements on a case-by-case basis for both impingement and entrainment, and do so on a single schedule.

We also urge EPA to provide a determination that facilities already using a closed-cycle cooling system should be deemed compliant with the proposed rule, and not required to modify their intake structures. AEP owns or operates ten such facilities subject to this rule. We are concerned that even with a system that clearly minimizes impingement and entrainment, we are now faced with large expenses to meet newly proposed requirements which would have little, if any, measurable environmental benefit.

Very truly yours,

Alan R. Wood, P.E.
Director – Water & Ecological Resource Services
American Electric Power Service Corporation

EXHIBIT
PENGAD 800-631-6989
SC-9

Comments of American Electric Power, Inc. on Proposed 316(b) Regulations
Docket No. EPA-HQ-OW-2008-0667

American Electric Power (AEP) is pleased to provide these comments on EPA's proposed regulations to implement Section 316(b) of the Clean Water Act applicable to cooling water intake structures (CWIS) at existing facilities and Phase I facilities. We are also submitting these comments on behalf of the Ohio Valley Electric Corporation with which we share an interest in two plants. With our partners, AEP owns and operates a total of 33 electric generating facilities in the states of Ohio, West Virginia, Virginia, Kentucky, Indiana, Michigan, Arkansas, Louisiana, Oklahoma, and Texas which are subject to this rulemaking. Those facilities comprise 6% of the 559 power plants to which EPA indicates the rule applies. These facilities are located on a wide variety of water body types (Great Lakes, Ohio River, inland rivers, constructed cooling ponds, natural lakes). We understand EPA's difficulty in establishing reasonable, scientifically defensible fish protection regulations in light of the diversity of water body types and their associated aquatic populations. We strongly believe, however, that the agency needs to recognize that the potential risk of adverse environmental impact caused by impingement and/or entrainment is not uniform among the various water body types and settings.

A. General

1. Implications of cumulative environmental rules – AEP is concerned that the number of current rulemakings which would govern various emissions and releases from steam electric power generating facilities, as well as setting standards for cooling water intake structures, will have a significant impact on the reliability of the national electric grid and on the economy. AEP supports regulations that achieve long-term environmental benefits, but we remain concerned with the accelerated timeframes that EPA plans for implementation of these rules. We believe that the agency should give careful consideration to comments from the actual operators of the facilities affected by the rule, who have first-hand knowledge and experience in designing and installing environmental retrofits. Our comments below regarding the implementation schedule for the 316(b) rule provide more specific details on this issue.

2. Comments from other organizations – AEP is a member of the Utility Water Act Group (UWAG) and the Electric Power Research Institute (EPRI), as well as the Ohio Utility Group (OUG) and the Association of Electric Companies of Texas (AECT). UWAG, EPRI, OUG and AECT are independently filing comments on this rulemaking and AEP supports those comments. Also. comments are being filed separately by AEP on behalf of its Donald C. Cook Nuclear Plant, owned and operated by the Indiana Michigan Power Company, a wholly-owned subsidiary of AEP. The comments from the Cook Plant provide EPA with details on the plant's site-specific issues as they would manifest under the proposed rules. We support those comments and believe that they will provide EPA with the necessary technical details to affect changes that are warranted in the proposal.

3. Site-specific approach – AEP supports EPA's proposal to establish a site-specific compliance plan for entrainment. State permit writers are in the best position to develop NPDES permit requirements for reducing entrainment mortality, where needed, on a case-by-case basis, taking into account costs and benefits and potential effects on energy supply and reliability. As proposed, this approach must be taken due to the host of site-specific conditions such as: species of fish present, type of water body, configuration of the intake, and time of year. In fact, it has been the experience of AEP that State permit writers have successfully implemented Section 316(b) for over 30 years to reduce the environmental impacts of cooling water intake structures, using a Best Professional Judgment (BPJ) process. In our discussion of the proposed rule with several State regulators, it is clear that the States believe that they are in the best position to evaluate potential impacts of cooling water intake structures on local water bodies and fish populations. Many states also believe that they have already achieved the appropriate level of control at facilities to minimize adverse environmental impact. We whole-heartedly agree with this process and note that we have worked cooperatively for several decades with our State agencies on this issue. We believe EPA should continue to build on that foundation by allowing flexibility to determine whether further studies or technology changes are needed at each affected facility, rather than assuming that insufficient progress has been made, and that every plant must now make changes. We further recommend that EPA allow State agencies to make site-specific determinations regarding impingement on a case-by-case basis, and do so in conjunction with their assessment of possible entrainment controls, as discussed in more detail elsewhere in these comments.

4. Plants with closed cycle cooling should be deemed already in compliance – AEP requests that EPA clearly acknowledge that facilities with closed-cycle cooling should not be required to make further modifications to reduce impingement or entrainment and should be deemed to be compliant with the requirements of Section 316(b). As EPA states, we agree that closed-cycle cooling should not be required as "best technology available" because it is not feasible to retrofit this technology at most sites and, even at locations where it may be possible, would likely result in other adverse environmental and energy impacts. Further, we believe that the cost of such retrofits would far outweigh any environmental benefit that could be reliably measured. AEP provides information on those costs for facilities that already have close cycle cooling, elsewhere in these comments. Therefore, following EPA's assessment that closed cycle cooling serves to achieve the goals of Section 316(b), where this technology is already in place, AEP strongly recommends that these facilities should be deemed to achieve BTA for minimizing adverse environmental impact and that no further action is required.

5. Timing issues because of separate requirements for impingement and entrainment – AEP believes that there is an overall disconnect between the impingement and entrainment compliance paths as written in the rule, even though they both affect the same physical structure and system. This includes the separate timing for compliance solutions between these two aspects and the requirement to consider impingement as part of the entrainment evaluation. As an example of this disconnect, for a facility with both design and actual intake flows greater than *125 MGD, the process for compliance with the impingement standards requires that the* owner/operator of the affected facility must confirm its determination at the end of a study phase that ends 3½ years after the effective date of the rule as to the technology solution to be employed to meet either the proposed velocity standard or the impingement mortality standard. Then the facility must ultimately implement the technology as soon as possible but no later than 8 years after the effective date. However, the entrainment compliance process for the same facility does not require the submittal of all relevant information until 5 years after the effective date. At which point, a determination by the permitting agency regarding any technology changes would follow, presumably many months after a thorough review of the information. The juxtaposition of the submittal timeframes and the implementation timeframes for impingement and for entrainment clearly show that the possibility exists that a technology solution installed under this rule for impingement control could be totally replaced by a later decision on entrainment that dictates a wholly different technology. This bifurcated approach does not make sense and results in the potential for significantly wasted resources (e.g., capital costs, manpower, etc.) on both the part of the permittee who installed the (suddenly insufficient) technology and on the part of the permitting agency who separately reviewed the impingement information. AEP strongly recommends that EPA revise the timeframe for impingement compliance in order to be aligned with that for entrainment, and that a single, site-specific determination is made by the Director upon receipt on a unified schedule of all relevant information related to both impingement and entrainment.

6. Location of intake should be taken into consideration – The language in the Clean Water Act regarding cooling water intakes refers to the location of the intake as being important to compliance. Specifically:

> …that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. (Emphasis added.)

As explained in detail in AEP's comments submitted separately by the Donald C. Cook Nuclear Plant, the location of a cooling water intake structure can dramatically affect the level of both impingement and entrainment. While the location of the intake can clearly be taken into consideration in the decision-making surrounding levels of entrainment mortality, EPA's proposal offers absolutely no such consideration when making a determination on impingement. Regulated facilities are offered only two choices, neither of which allows for a conclusive determination that an intake structure already meets the goals of Section 316(b) due to its location. Based on the technical details provided by AEP in our comments filed by the Cook Plant, we strongly urge EPA to provide a mechanism for consideration of the location of an intake as a means of establishing compliance with the rule for impingement mortality, consistent with the statutory language.

7. **Insufficient time for initial submittals** - The proposed rule contains several unrealistic timeframes for submittal of data. In several parts of the rule, facilities are only given 6 months from the effective date of the rule to submit detailed reports of what EPA considers to be existing information. However, only a portion of this information currently exists. EPA should allow at least one year for this requirement to be fulfilled. Specifically, this refers to the submittal requirements for data regarding source water, existing intake structure, source water biota, cooling system operations, and past performance studies, as well as the submittal of an impingement compliance plan for facilities $\geq$ 50 MGD design intake flow. EPA incorrectly assumes that all facilities collected this information under the previous rule, specifically the source water baseline biological characterization data.

8. Implementation schedule issues - EPA has placed the entire country on the same schedule of compliance with this rule. AEP has concerns with the availability of qualified consultants that will be needed to conduct the many detailed studies required by the rule. Further, the rules will require "peer reviews" and we have similar concerns about the availability of qualified reviewers. Since the States will be required to administer this program, we can envision that at least in some states their resources will be taxed to review and render decisions on all affected facilities within their jurisdiction on the same schedule.

AEP is also concerned about the ability of manufacturers to produce the required components for technology installations for a national fleet of power plants and manufacturing facilities that are all placing orders at the same time.

Additionally, the installation of any structure below the surface of the water will require specialized labor (divers). The supply of qualified divers is limited, and AEP is concerned that the existing pool of contract diving firms would be stressed if compliance with impingement and entrainment requirements would be concomitant on a national basis. AEP has estimated the diving labor requirements for a scenario in which cylindrical wedge wire screens are retrofitted to plants which employ once-through cooling systems and shoreline intakes with traveling water screens, in order to meet the proposed velocity standard. At one facility retrofitting two generating units with a total of 36 standard screens, the diving estimates from two sources ranged from 25,440 to 36,700 man-hours (3,000 – 4,500 man-days.) For another similar facility, the diving estimates to install 66 screen assemblies ranged from 6,522 to 10,240 man-hours. These estimates also demonstrate the site-specific nature of this type of specialized work. However, we believe that even the lower end estimates, when scaled to a national level, clearly show that contract diving firms would be oversubscribed.

Finally, an additional implementation schedule issue relative to retrofitting facilities involves diver safety. Due to safety concerns, professional divers will typically not work in conditions where flow velocities in the work area are measured in excess of 2.0 ft/sec. As a result, constraints on diver availability may be further exacerbated by seasonal high flow conditions in certain rivers or by periodic flooding such as the flooding that occurred in the Mississippi and Missouri River basins earlier in 2011. Should a similar flooding event occur in any of the watersheds with sources impacted by this rule, either months or perhaps an entire construction season could be lost for screen assembly installations due solely as a result of unsafe in-stream work conditions for the diving contractors.

EPA should align the timing of this program with the NPDES wastewater discharge permit cycle for each facility, since those permits are the vehicle for implementing these rules.

9. **"Re-review" of past determinations** – The comprehensive compliance process in the rule should be limited to a "one time" review and not potentially fully revisited with every permit cycle after the initial compliance solution is implemented. The rule requires the permitting agencies to revisit the previous determination with each permit renewal as specified in Section 125.95(e). However, once a BTA determination is made, it realistically should only be subject to

a subsequent comprehensive review in cases where the facility has been modified in a way that changes the characteristics of the intake, or if EPA changes these regulations. For all other cases, the permitting agency should only be required to undertake a limited review to determine if conditions have changed significantly.

10. Cooling ponds/reservoirs originally constructed as closed-cycle systems should not be treated as natural lakes - In locations where significant sources of water were not available, many companies constructed cooling water ponds or reservoirs adjacent to their new plants. AEP constructed six of these types of facilities that are located in Texas and Oklahoma. These are considered to be a closed cycle cooling system since the water is reused. Given their size, many reservoirs have also become resources within the States for fishing and recreation, at times enhanced by wildlife agency stocking. Under the proposed rule, EPA appears to be regulating these reservoirs as though they were natural lakes and requiring controls to protect fish populations in them. These fish populations have grown to support active sport fishing while the power plants have been in operation the entire time. It is illogical that EPA would have companies spend millions to further protect these fish. Facilities with cooling ponds or reservoirs constructed to specifically support the plant should be treated the same as plants with closed cycle cooling tower systems, regardless of the level of other uses of the reservoir.

11. Point of compliance – The rule should clarify that facilities with channels or canals leading to/from a cooling pond or reservoir are not subjected to the requirements at the plant wall, but only at the point of make-up to the reservoir from a true *"Water of the U.S."*, regardless of the classification of the cooling reservoir.

12. Facilities with low capacity factors - Facilities that run infrequently will be unable to generate the type of data that EPA calls for in the various submittals (e.g., entrainment numbers for each season, etc.) These facilities present a *de minimis* level of impact and this aspect was previously incorporated in the Phase II 316(b) rule for existing facilities. This aspect of the previous rule was not challenged nor specifically overturned. The logic behind its presence in that rule stands today. Therefore, we strongly urge EPA to re-incorporate the previously available exemption for facilities with capacity utilization rates less than 15 percent.

13. Calculation of "Actual Intake Flow" for use in determining applicability – It is not clear from the definition of "Actual Intake Flow" how it is to be specifically calculated. AEP believes that it is EPA's intent to determine AIF by taking the actual gallons withdrawn over the three year period and dividing by (3 x 365 days) rather than dividing by the number of days of operation during those three years. We ask that EPA provide this clarification in the final rule.

14. Undefined process for small facilities - The status of facilities below the various flow thresholds are left in somewhat of a vacuum not knowing what the permitting agency will require. We believe that EPA has based its proposal containing the various flow-based thresholds on its analysis that facilities below these levels pose little relative risk of adverse environmental impact. Therefore, it follows that EPA should in the final rule render its decision that facilities below these thresholds already meet the BTA requirement of the statute. We recognize that there may be unique situations where a permitting authority believes that a facility is, in fact, having an adverse environmental impact. To allow for this, since the state or regional permitting authorities are in the best position to judge this, we recommend that the final rule provide for such exceptions by including language that would allow the permitting authority to override EPA's blanket determination and require that a site-specific analysis be conducted.

B. Impingement

1. Rule does not provide for any alternative approaches which could meet the same impingement goals – As proposed, the rule only provides two compliance choices: 1) meet an intake velocity standard, or 2) meet a percent mortality standard for fish collected on screens. While we understand EPA's decision that these two approaches are "available" for all facilities, AEP strongly believes that EPA needs to consider that facilities with fundamentally different factors (i.e., alternate intake technologies) may, in fact, meet the same basic goals of the impingement standards. As more fully described in the comments submitted by AEP's Cook Nuclear Plant, facilities such as this with submerged, off-shore intakes ***already achieve*** similar impingement mortality reduction goals without any modifications. It would be irresponsible for EPA to require such facilities to retrofit other technologies where the marginal increase in impingement mortality reduction is negligible in comparison with the associated costs. Therefore, we strongly urge EPA to include an option allowing for a demonstration by the facility that the impingement goals may be met either by the existing cooling water intake structure or installation of some alternate technology other those envisioned by the proposed rule. We note that EPA provides for some discussion of these alternate technologies in the preamble and support documents, but fails to develop this aspect into the rule.

2. No recognition of facilities with very low impingement rates – As proposed, the rule fails to acknowledge that facilities may actually experience absolute levels of impingement that are literally counted in the tens of numbers of fish. Clearly these facilities are not causing adverse environmental impacts due to the loss of only a few dozen fish per month. Natural mortality rates far outweigh incremental, power plant caused mortality. The proposed rule contains no consideration for facilities with *de minimus* levels of impingement. Facilities could be required to spend several million dollars on a compliance technology even though their impingement rate is measured in such small numbers. Clearly these situations would not meet any rational cost/benefit analysis. We strongly urge EPA to make the determination that facilities below a minimum level of absolute impingement meet the BTA standards. Such a *de minimis* threshold could be defined as total number of fish impinged on an annual basis, or on faunal redundancy (e.g., > 95% of all fish impinged comprised of a highly fecund forage species). Alternatively, perhaps a decision on an appropriate *de minimus* level is best determined on a state- or site-specific basis by the permitting authority and made a responsibility of the Director.

3. Cost/benefit analysis is absent – As proposed, the rule provides for no measure of judgment in determining if the installation or retrofit of technology solutions for impingement mortality control is wholly disproportionate with the environmental benefits. While EPA has developed its approach based on an its own analysis of costs and estimates of benefits, for which the background data is extremely difficult to discern, the information provided does not show a clear, rational explanation that the expected benefits are in proportion with the costs of implementation of technologies. In fact, EPA's analysis yields a 21.8 to 1 cost-benefit ratio. The agency goes on to rationalize that the costs are justified because non-use benefits were not fully quantified. Even so, we can not envision a world where non-use benefits would be determined to be so valuable as to bring this ratio anywhere near 1 to 1. We firmly believe that setting regulatory policy based on national averages and this cost-benefit analysis unfairly penalizes facilities where site-specific benefits are, in fact, not justified by actual site costs. Therefore, EPA must include a site-specific cost-benefit analysis as part of the decision-making for impingement mortality control.

4. Costs - AEP has developed initial estimates for compliance costs for the two options for reducing impingement mortality (velocity option & mortality option). As explained elsewhere in these comments, we believe that the benefits associated with the installation of technologies to achieve these standards is far outweighed by these costs and strongly urge EPA to include a consideration of costs in determining whether the existing intake structures meet the BTA requirement of Section 316(b).

i. Cost of retrofit of wedgewire screens to reduce velocity to 0.5 fps – AEP's preliminary estimates to retrofit wedge wire screen systems at the 33 plants referred to in our introductory comments is approximately $245.000,000 with annual estimated operating & maintenance costs of approximately $2.900.000.

ii. Cost of fish-friendly screen & return system retrofits – AEP's preliminary estimates to retrofit fish-friendly traveling water screen and fish return systems at the 33 plants referred to in our introductory comments is approximately $233,500.000 with annual estimated operating & maintenance costs of approximately $20.300,000 .

iii. Costs for facilities that already have closed cycle cooling. – In addition to the total costs above, as a subset of item (i), AEP's estimated costs associated with retrofitting cylindrical wedge wire screen assemblies to power plants <u>which already employ closed cycle cooling</u> but which do not meet the 0.5 fps velocity criterion. These costs vary from a low of $1.9 million to a high of $6.25 million per plant. We believe that these capital expenditures are wholly unwarranted for facilities that already have systems which EPA considers to be best technology, even though it is not "available" on a national basis.

5. Monitoring requirements for fish mortality have inherent problems – We would like to point out the difficulties and inherent problems due to the sampling regime/protocol for the mortality reduction option. The rule requires twice monthly sampling by collecting and holding for 24 hours all fish collected in order to determine mortality rate. We believe that EPA has not fully recognized the practical problems associated with assessing *impingement caused-mortality* when *non-impingement factors* have an equal chance of causing stress and, potentially, mortality. These problems include:

- Maintenance of suitable water quality (temperature, oxygen, contaminants) in the holding facility,
- Effects of predation among individuals and species,
- Effects of handling, and
- Confinement to a small space.

Additionally, EPA must clarify that any mortality criterion needs to apply to only species of concern, and that a minimum number of fish (we suggest 20 fish for an individual species and 100 fish for all species evaluated) needs to be collected during an impingement event to provide some degree of statistical robustness. Due to these issues, we request that EPA seriously reconsider its approach to verification that traveling water screen systems are being properly operated based on the many random and uncontrollable factors that affect impingement mortality. We would suggest that EPA focus on the maintenance of operating records as such a means.

6. EPA should offer an option to allow for determining a site-specific velocity threshold for intakes based on indigenous species of concern, rather than the "one size fits all" of 0.5 fps. As fully explained in the comments submitted by the Utility Water Act Group (UWAG), AEP staff attempted years ago to determine the source of valid technical information supporting the 0.5 fps velocity guideline, and ultimately determined that no basis existed for that number. Should EPA not amend this standard, we strongly urge EPA to provide a mechanism to allow State permitting authorities to determine a site-specific velocity standard based on actual species and life stages present, and the intake structure design. The details of AEP's findings described in the UWAG comments regarding fish swim speeds provide sufficient justification to support this option.

7. **Establish a technology standard rather than numeric mortality standards** - If EPA has determined that fish-friendly traveling screens with fish return systems can achieve compliance (76 FR 22187), then why must a facility be subject to continued monitoring and limits? Given the limitations inherent in biological sampling (as described above), we strongly believe that installation of a technology that meets design and operating criteria specified by EPA should suffice as meeting the BTA requirements of the rule. The imposition of inflexible monthly and annual "not to exceed" limits on mortality also presents an unacceptable risk of a facility's compliance record. If EPA establishes mortality standards, they have the same implications for enforcement as do numeric effluent limits for pollutants in wastewater discharges. Given the highly uncontrollable nature of the parameter being measured (fish) and the fact that fish impingement rates do not vary as a direct function of CWIS pumping rates, it is unacceptable, and frankly unfair, to subject facilities to the same potential penalties and enforcement actions as is done with respect to pollutants under the Clean Water Act. The health of a single individual fish can make or break a facility's compliance record. We also would like to point out that suppliers of traveling screen systems will not provide performance guarantees with respect to impingement mortality. Again we make the analogy to wastewater discharges in that suppliers of wastewater treatment systems typically provide a performance guarantee that the system they

design will meet the required effluent limits. In the case of traveling screens, owners face a much higher risk factor for noncompliance since there will be no guarantees.

8. Counting fish in carryover and debris management should only apply to the percent reduction option. Section 125.94(b)(2)(v)(A) requires that fish that are included in carryover must be counted as impingement mortality. We note that this section is a part of the velocity standard compliance approach and as such contains no requirements to enumerate impinged fish. Therefore we believe this requirement has been included in error.

9. Commitment to a compliance approach within six months after the effective date of the rule is unreasonable. For facilities with a design intake flow greater than or equal to 50 MGD, the owner or operator must commit under Section 122.21(r)(6) to which compliance option it will pursue (velocity vs. percent mortality) within six months of the effective date of the rule. They must also submit a study plan indicating how this approach will be implemented and verified as compliant. It is absolutely unreasonable to expect facilities to fully analyze the financial, technical, operational, and compliance risk aspects of these two options within six months of the effective date of the rule in order to make an informed decision which commits them to a compliance strategy. As evidenced by the five year study process for entrainment, these types of decisions are not made based on "back of the envelope" calculations. Given the precedent set by the entrainment timeline, EPA must provide sufficient time for regulated facilities to fully analyze their options and then make a decision. Notwithstanding our firm position that the impingement and entrainment compliance decisions need to be merged into one analysis. EPA should allow the facility to study both options during the impingement mortality reduction study period and at the end of that period then advise the agency of its decision.

10. Cooling ponds should not be burdened with entrapment requirements since most are habitat for full-time resident populations. To the extent that EPA considers cooling ponds that are not otherwise classified as "*Waters of the U.S.*" as part of a cooling system, the requirements in Section 125.94 to provide for a means for impingeable fish or shellfish to escape the intake system and be returned to the water body, are unclear. It is common for cooling ponds to support persistent resident populations of fish. Is it EPA's intent to provide for those fish to "escape" the cooling pond and be returned to the source of make-up water to the pond, even though they did not originate from that source? This is somewhat akin to requiring a facility to collect and remove fish from its thermal discharge plume even though they are attracted there by an optimal temperature environment. Surely this does not make sense. We urge EPA to clarify this requirement. In fact, we request that EPA remove the requirements related to entrapment from the rule for the reasons described in the comments provided by UWAG.

C. Entrainment

1. Clearly instruct the permitting authority to use cost/benefit analysis in final decision – The cost/benefit decisions related to decisions on entrainment appear to be optional when the permitting agency should be required to consider issues of costs vs. benefits. AEP firmly believes that where a regulatory decision is allowed to factor in the costs and societal benefits of an action, it must do so as a clear tenet of responsible government. To allow a seemingly optional exercise of judgment on the cost/benefit analysis is an abdication of that responsibility, especially in light of the Agency's analysis that shows benefits to be extremely outweighed by costs.

2. Facilities should not be required to evaluate dry and hybrid cooling systems – As we read the requirements for entrainment mortality compliance, we believe that EPA is requiring facilities to not only evaluate the common wet closed cycle cooling tower option, but also conduct a feasibility analysis of other closed cycle technologies including dry cooling and hybrid cooling (combination of wet & dry). EPA has already determined that these alternative closed cycle technologies are too costly and energy intensive for application to new facilities. Therefore it is logical that they must also be similarly unjustified for retrofit to existing facilities. On a more technical note, use of dry and hybrid cooling technology is clearly not economical where predominant weather conditions of temperature and humidity make these systems inefficient. Facilities in these areas should not be required to analyze a technology that would not even pass the first round of an engineering alternatives analysis. Therefore, we strongly urge EPA to clarify this in the final rule such that facilities are not required to study the feasibility of dry or hybrid closed cycle cooling unless the state or regional permitting authority provides clear evidence that these technologies are suitable based on predominant weather conditions at the specific location.

3. **Facilities should not be required to evaluate the feasibility of purchasing additional land** to accommodate cooling technology retrofits. EPA requires as part of the comprehensive technical feasibility and cost evaluation study that the owner provide a discussion of land availability including an evaluation of "adjacent land". We interpret this to mean property not currently owned by the facility. We believe that it is beyond EPA's authority under the Clean Water Act to require facilities to potentially expand in size.

4. **Uncertainties of the peer review process** – While AEP understands that a peer review process does have benefits (e.g., increasing the scientific validity of a study design), there are many pitfalls that could arise to the detriment of a facility seeking to elucidate the risk of entrainment impacts. EPA offers no guidance or limitations on the duration of this step (more detailed comments on this concern follow), whether a facility must accept ***all recommendations*** made by ***all peer reviewers***, and how a potential conflict of interest could be avoided. EPA should clarify that the primary function of peer review is for facilities to obtain reasonable recommendations on fostering a scientifically defensible study design, and data analysis procedures. In fact, a provision should be made to allow the peer review to be accomplished by state resource agencies, should a state already have that expertise.

5. **Lack of mandatory review time limits** – The proposed rule fails to include specific requirements for time limits in providing responses by both peer reviewers and permitting agencies. Notwithstanding our comments on the peer review process, the lack of clear requirements for time limits in providing the various reviews and approvals is unacceptable

given the ultimate compliance deadlines required by the rule. It is unreasonable to expect permittees to achieve these goals when portions of the critical path timeline to compliance are open-ended. We strongly urge EPA to amend the proposed rule by including specific, reasonable timeframes for responses by peer reviewers in providing their reviews and by permitting authorities in providing approvals, as required by the rule. As is provided for in many other regulations, the permittee should be allowed to proceed should a response not be received by the end of the allotted review period.

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AMERICAN ELECTRIC POWER

Water Docket
U.S. Environmental Protection Agency
Mail Code: 4203M
1200 Pennsylvania Avenue
Washington, D.C. 20460

Attention Docket ID Nos. EPA-HQ-OW-2009-0819 and EPA-HQ-RCRA-2013-0209

September 20, 2013

Comments of the Operating Companies of the American Electric Power System Inc. on Proposed Rule for Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category - Docket Nos. EPA-HQ-OW-2009-0819 and EPA-HQ-RCRA-2013-0209

Dear Sir or Madam:

The operating companies of the American Electric Power System (collectively referred to as "AEP") offer the enclosed comments on EPA's proposed rule to revise the technology-based effluent limitation guidelines and standards for the steam electric power generating point source category, published at 78 Fed. Reg. 34432 (June 7, 2013). AEP is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP owns and operates all or portions of 112 coal-, lignite-, diesel- and gas-fired units at 43 facilities, and two units at its nuclear facility. All of these facilities would be directly affected by the proposed regulation.

AEP recognizes that updated federal technology limits are appropriate; however, we are concerned that many of the proposed changes are neither reasonable nor cost effective. AEP encourages EPA to reconsider the proposed regulation based on the comments presented with this letter. These comments are also submitted on behalf of the Ohio Valley Electric Corporation, and its subsidiary, the Indiana Kentucky Electric Corporation, as well as Buckeye Power, Inc.

AEP also encourages EPA to carefully consider the comments filed by the Utility Water Act Group (UWAG), the Utility Solid Waste Activities Group (USWAG), the Electric Power Research Institute (EPRI) and the Edison Electric Institute (EEI). AEP is a member of, and

EXHIBIT
PENGAD 800-631-6989
SC-10

participates in the activities of these organizations and incorporates by reference the comments that are being presented separately by these organizations.

If you have any questions regarding the comments, please contact Tim Lohner of my staff at 614-716-1255 or at twlohner@aep.com .

Sincerely,

John McManus

John McManus
Vice President
Environmental Services

cc: Ron Jordan – U.S. EPA, Office of Water

Comments of

the Operating Companies of the American Electric Power System on

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

Docket Nos. EPA-HQ-OW-2009-0819 and EPA-HQ-RCRA-2013-0209

September 20, 2013

Table of Contents

Page No.

Comments of the Operating Companies of the American Electric Power System on the Proposed Rule for Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category Docket Nos. EPA-HQ-OW-2009-0819 and EPA-HQ-RCRA-2013-0209

The operating companies of the American Electric Power System (AEP) provide these comments on the Environmental Protection Agency's (EPA's) proposed rule to revise technology-based effluent limitations guidelines and standards for the steam electric power generating point source category, published at 78 Fed. Reg. 34432 (June 7, 2013). We are also submitting these comments on behalf of the Ohio Valley Electric and Indiana-Kentucky Electric Corporations, with which AEP shares an interest in two plants, the Kyger Creek Plant in Cheshire, OH, and the Clifty Creek Plant in Madison, IN, and the Buckeye Power Company, with which AEP shares ownership of the Cardinal Plant in Brilliant, OH. With our partners, AEP owns and/or operates a total of 43 steam electric generating facilities in the states of Ohio, West Virginia, Virginia, Kentucky, Indiana, Michigan, Arkansas, Louisiana, Oklahoma, and Texas, which are subject to this rulemaking. This includes 24 coal-fired plants, 19 gas-fired plants, and one nuclear facility.

We appreciate EPA's efforts to collect representative information and establish reasonable and cost effective revisions to the steam electric effluent guidelines in light of the diversity of wastewaters generated by sources within this category and the wide range of associated treatment technologies. Given that diversity, the agency needs to recognize that the affordability and effectiveness of the proposed technologies varies greatly in their application to the specific waste streams at specific facilities within the industry. All too often, the agency has made inaccurate assumptions based on very limited information from a few facilities, or has combined or otherwise "averaged" treatment performance characteristics, masking individual treatment effectiveness and presenting overly optimistic affordability figures. AEP urges EPA to carefully review and revise its cost estimates, and reconsider certain of its preferred options based on the comments presented herein.

A. General

1. Clean Water Act, Role of Effluent Guidelines and their Legal Basis

On June 7. 2013, EPA published its proposal to revise the technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. 78 Fed. Reg. 34432 (June 7, 2013). Existing regulations can be found at 40 C.F.R. Part 423. Comments on the proposed rule were originally due on August 6, 2013 (or 60 days following publication). On July 12, 2013, in response to multiple requests, EPA extended the comment period by 45 days or until September 20, 2013. Notice of EPA's extension of the comment period was published on July 12, 2013 at 78 Fed. Reg. 41907. We wish to express our appreciation for the additional time to review the proposal; however, we find that it is still inadequate given the multiple options and the volume of supporting information presented by the agency.

In proposing the guidelines and standards, EPA relies on the authority of the Federal Clean Water Act §§ 301,304, 306, 307, 308, 402, and 501, 33 U.S.C. §§ 1311, 1314, 1316, 1317, 1318, 1342, and 1361. The Clean Water Act provisions prohibit the discharge of pollutants from a point source, unless authorized to do so pursuant to a National Pollutant Discharge Elimination System (or NPDES) permit. EPA is directed to promulgate technology-based effluent limitations for discharges from categories of existing point sources (and new source performance standards for new sources) that are then included in an individual NPDES permit to discharge. EPA may issue an individual NPDES permit or states may make a submittal to the EPA administrator for approval to administer their own permit program.

EPA states that it is revising the current regulations because "[t]he current regulations, which were last updated in 1982, do not adequately address the toxic pollutants discharged from the electric power industry, nor have they kept pace with process changes that have occurred over the last three decades" (78 FR at 34435). EPA indicates that the proposed regulation is aimed at new or altered waste streams that have resulted in increasing the "volume and mass" of pollutant discharges (Id.). EPA goes on to state that the proposed rule would reduce these "current toxic and other pollutant discharges and their associated impacts" (Id.). The new processes and byproducts which are the focus of the rule are: flue gas desulfurization (FGD), fly ash, bottom ash, flue gas mercury control, combustion residual leachate, nonchemical metal cleaning wastes, and gasification of fuels. EPA also proposes to establish best management practice (BMP) requirements that would apply to surface impoundments. In the proposal, EPA has identified eight regulatory options to address the existing discharges stating a preference for four of the eight alternatives for existing sources and one favored alternative for new sources. The actual proposed regulatory language is based on the most-favored alternative.

In order for the proposed guidelines and standards to become final regulations, following internal agency review, the Administrative Procedures Act, 5 U.S.C. § 553 requires that the proposal be published in the *Federal Register* and allow for interested persons to participate in the rulemaking. Following the comment period, EPA considers the relevant information and publishes the final substantive rule. Interested persons may request EPA to review, reconsider or revise certain portions of the rule. The Agency is under no obligation to make any changes to the rule once it is final.

A shortcoming of this process is that persons affected by the rule must comply immediately and, if aggrieved or adversely affected, they have little recourse and are forced to rely on guidance and interpretive documents to assuage a rule's impact. A final rule decision may be challenged by an appeal to the U.S. Court of Appeals for the D.C. Circuit, challenging a rule's constitutionality, the agency's authority or the rulemaking process, claiming that the Agency's actions are arbitrary, capricious, or an abuse of its discretion. Unfortunately, this is a costly, risky and time consuming process and compliance with the rule is still required unless the reviewing court stays the rule's effective date.

2. **The use of litigation to drive federal agency environmental agendas must not prohibit meaningful participation in the public notice and comment process for the revised effluent guidelines.**

Increasingly, environmental non-governmental organizations (ENGOs) have filed suit based on EPA's failure to complete reviews or revisions of regulatory requirements, and in some cases, to do so within the time periods set forth in the applicable statutes. Such suits are regularly settled by consent agreements that commit EPA and other agencies to undertake rulemakings and other actions by specified deadlines. In turn, the ENGOs and agencies have usually opposed the regulated community's participation in the suits and have denied them the opportunity to provide input on the adequacy of the proposed schedules. For example, The Defenders of Wildlife and The Sierra Club have sued EPA claiming that the Clean Water Act (CWA) imposes on the agency non-discretionary duties, which the agency has failed to perform. These duties include completing a review of the currently effective effluent limitations and associated guidelines for steam electric plants, making a decision as to whether or not to revise those limitations and guidelines and completing a rulemaking necessary to achieve the revisions. The Utility Water Act Group (UWAG), as a representative of the electric utility industry, including AEP, moved to intervene as a defendant in this action; however, both of the parties opposed UWAG's motion.[1] Neither party quarreled with the timeliness of UWAG's motion. nor did either pretend that EPA adequately represents UWAG's interest. Instead. they argued that UWAG had failed to claim the requisite interest in this action and the Consent Decree by which the parties propose to resolve it. The Court also approved a settlement agreement setting the schedule for the effluent guideline (ELG) rule revision.

Based on that schedule. EPA initially provided only 60 days to review and develop comments on the current proposal, and committed to finalize the rule less than one year after its publication in the *Federal Register*. Although an unofficial, signed copy of the rule was made available prior to publication. the original 60-day comment period was not nearly long enough to allow sufficient commenting on the proposal. In addition, critical supporting data. including the Technical Development Document (TDD), were not made available until after the publication date. After receiving numerous requests for an extension. EPA did extend the comment period by 45 days, but the resulting 105-day comment period was still not long enough to allow for the submittal of comprehensive comments.

To address the issue of data availability, AEP and other companies submitted FOIA requests so that they could confirm the accuracy of confidential data that was provided to EPA. and which formed the basis for certain of EPA's analyses and conclusions. The FOIA process consumed additional time during the comment period. As is specifically noted later in these comments, some of that data was in fact inaccurately represented or misinterpreted by EPA. and does not support the conclusions in the proposed rule.

[1] Defendant Lisa P. Jackson's Opposition to Motion by the Utility Water Act Group to Intervene as Defendant (filed Dec. 2, 2010) (Defendant's Opp.); Plaintiffs' Opposition to Utility Water Act Group Motion to Intervene as Defendant (filed Dec. 3, 2010) (Plaintiffs' Opp.).

AEP recognizes that EPA has statutory obligations to review and revise, if appropriate, certain standards on a periodic basis. Under sections of the Clean Water Act applicable to these ELGs, that review is not required to be completed on any specific schedule, and the agency has the discretion to undertake and complete its review on a schedule that accommodates the need to collect, verify, analyze, and draw appropriate conclusions from relevant information. The establishment of arbitrary deadlines in a litigation setting with parties whose only concern is updating the standard, regardless of cost or feasibility of implementation, short-circuits the process of public review and comment required under the agency's enabling legislation, and ignores the highly complex and technical nature of the standard-setting process.

The industries affected by a regulation should not be excluded from the discussions regarding the rulemaking schedule. AEP and the rest of the electric utility industry are significantly affected by the ELG rulemaking. They are uniquely positioned to provide technical comments on the proposal, but are disadvantaged when an arbitrary schedule is imposed by a court without any input from the affected industry. EPA's recent commitment to provide notice of the so-called "deadline suits" and any settlements being contemplated is insufficient to protect the regulated community (and the broader public interest represented by consumers, other industries, and small businesses that are impacted by increasing prices for electric service) from the adverse impacts of proceeding to finalize a rule without adequate opportunity for public comment. Those risks also affect EPA, which has granted reconsideration in a number of complex rulemakings affecting this industry, in order to take into account information that was not specifically requested, but later provided, and had a substantive impact on the rulemaking.

Given the inaccuracies noted herein, and the substantial questions remaining about how EPA arrived at the costs associated with implementation of certain of its preferred alternatives, it is appropriate and necessary for EPA to issue a supplemental notice that corrects any errors, describes the additional information provided by affected sources, and seeks further comments on EPA's analysis of this information and any changes made based on that analysis. A supplemental notice of data availability will provide all interested parties a full and fair opportunity to examine the data and support their positions based on the most accurate and representative information available. It is unlikely that this process can be completed by the current deadline EPA has negotiated, and EPA should seek an extension of that deadline in order to assure that there is adequate time to comment on and complete this complex rulemaking.

3. Comments from Other Organizations

AEP is a member of the Utility Water Act Group (UWAG), the Utility Solid Waste Activities Group (USWAG), the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI), the Ohio Utility Group (OUG) and the Association of Electric Companies of Texas (AECT). UWAG, USWAG, EPRI, EEI, OUG and AECT are independently filing comments on this rulemaking. AEP supports those comments and believe that they will provide EPA with the necessary technical details to affect rule changes that are warranted.

4. Implications of Cumulative Environmental Rules

AEP is concerned that the cumulative impact of the extraordinary number of current rulemakings which would govern various emissions and releases from steam electric power generating facilities, as well as setting new effluent guidelines standards, controls on cooling water intakes, and coal combustion residual (CCR) requirements, will have a significant impact on the reliability of the national electric grid and on the economy. AEP supports regulations that achieve cost-effective, long-term, environmental benefits, but we remain concerned with the accelerated timeframes that EPA plans for implementation of these rules. We believe that the agency should give careful consideration to comments from the actual operators of the facilities affected by the rule, which have the first-hand knowledge and experience in designing and installing environmental retrofits. Our comments regarding the implementation and coordination of the schedule for the ELG and CCR rules provide more specific details concerning this issue, but additional coordination of implementation timelines should be considered for all of the pending regulatory actions that affect these sources.

5. Intersection Between the Proposed ELG and CCR Rules

EPA is seeking to coordinate any final RCRA Coal Combustion Residuals (CCR) rule with the ELG requirements to minimize the overall complexity of these two regulatory structures and facilitate implementation of engineering, financial and permitting activities (78 FR at 34441). AEP not only agrees that EPA should coordinate the two rulemakings, but that it has a statutory obligation to do so under RCRA Section 1006(b) to avoid duplication with the appropriate provisions of other federal statues, including the ELG rule.

EPA anticipates that a possible consequence of the proposed ELG requirements is that a number of facilities will choose to convert their fly ash or bottom ash sluicing operations to dry ash-handling systems and will no longer send such waste to surface impoundments (Id.). It is also likely that some facilities will be retired and closed, leaving "legacy" wastewaters in the impoundments. The ELG proposal contemplates the continued operation of the impoundments and the discharge of the legacy transport water (i.e. ash transport water already in the pond), yet the proposed CCR rule requires the relining or closure of these same ponds. A prohibition on the discharge of pollutants from fly ash sluice water as proposed under EPA options 3, 3a, 3b, 4a, 4, and 5, and from bottom ash transport water, as proposed under EPA Option 4a, 4, and 5, would mean that many surface impoundments would no longer receive CCRs. This would trigger the proposed CCR rule requirement that closure activities begin within 30 days of the last receipt of CCR materials and be completed within 180 days of the date of closure (75 FR at 35128, 35252). *Thus, a prohibition on the discharge of fly ash/bottom ash transport water would* have the unintended consequence of compelling the closure of impoundments under the proposed CCR rule, while under the proposed ELG rule, that particular impoundment may continue to be operated for some period of time until the legacy wastewaters have been discharged.

The compliance timelines of the proposed ELG *and* CCR rules overlap, making it difficult to conduct long-range planning. The implementation dates of one rule could require that decisions be made regarding a facility without knowing how those decisions would affect compliance under the other rule. For example, the ELG rule proposes under all options that compliance with the rule be achieved as soon as possible with the first NPDES permit renewal after July 1, 2017. Assuming adoption of ELG Option 4a, a steam-electric facility operating a wet fly ash system with an NPDES permit renewal date of July 31, 2017, must discontinue discharging fly ash transport water by that date. However, the agency makes reference to a compliance period that may be allowed by states.[2] Assuming a 3-year compliance period, this same facility would have until July 31, 2020, to comply with the new ELG requirements. However, the CCR rule requires that all CCR ponds be relined or closed within five years of the regulation's adoption. Assuming a CCR rule adoption year of 2014, the ash pond in question would have to be closed five years later in 2019, on a date occurring before that allowed by the

[2] EPA Regulatory Impact Analysis for the Proposed Effluent Guidelines and Standards for the Steam Electric Power Generation Point Source Category. EPA-821-R-13-005, [hereinafter EPA Regulatory Impact Analysis], April 2013.

proposed ELG rule. These inconsistencies need to be corrected and the timelines for the two rules need to be coordinated and reconciled.

AEP reemphasizes the comments that were submitted in the CCR rulemaking record that demonstrate that the time periods proposed for closure of existing impoundments are impractical and infeasible for larger impoundments. In addition, the requirements to eliminate discharges from bottom ash impoundments in the ELG proposed rule are not cost-effective, and should not be retained in the final rule. This is particularly true when one considers the additional costs associated with reengineering and developing new alternatives for handling other low volume wastewaters from existing facilities, which are commonly co-managed with bottom ash sluice water. AEP urges EPA to allow existing facilities to retain the option of handling bottom ash and other low volumes wastes in existing impoundments.

B. Cost Effectiveness Analyses

As required, EPA assessed the compliance costs and pollutant reduction associated with each of the proposed regulatory options. The agency's TDD provides an in-depth discussion of these analyses and offers insight on how they were accomplished. EPA estimated costs and pollutant loads on a per plant basis. To confirm these estimates, AEP conducted a similar analysis. However, it was found that, without exception, EPA under-estimated the costs and over-estimated the benefits of the proposed treatment options for each of the wastewaters that were analyzed by AEP (FGD wastewater, fly ash and bottom ash transport water, leachate, and nonchemical metal cleaning wastes). There are many reasons for this discrepancy, but AEP emphasizes the more important ones in the following comments. Please note that each of the following concepts were applied to AEP's cost analysis of the proposed revisions.

1. **The costs presented by EPA do not appear to include all the costs of doing business.**

The costs presented by EPA do not appear to include all the costs of doing business. AEP presents costs on a direct basis in these comments for comparison purposes, but a more accurate portrayal of expected compliance costs would be to "fully load" the direct costs with indirect costs, such as company overheads, as well as an Allowance for Funds Used During Construction (AFUDC). AFUDC is an accounting mechanism that recognizes the cost of debt and equity used to finance the construction of new utility assets. AFUDC is allowed for virtually all regulated utilities under FERC rules and allows a utility to capitalize the interest cost of construction.

Fully-loaded costs represent the total amount that will be borne by utility customers as a result of this regulation. EPA does not account for company indirect and overhead costs in its estimates, but it is standard practice to include these additional real costs as they are a necessary cost of doing business for any activity.

According to the AEP Cost Allocation Manual:

> "Indirect costs cannot be identified with a particular activity and must be charged to the appropriate activity or activities to which they relate using relevant cost allocators. Indirect costs include, but are not limited to, corporate or business unit overheads, general and administrative overheads, and certain taxes."

EPA's calculation of the full cost to affected facilities neglects to include these indirect costs and company overheads which are real costs that will be borne by a company's customers, and ultimately cause further underestimation of the compliance costs associated with these guidelines.

The AEP direct cost estimates include contingencies to cover difficult construction situations with limited acreage for installing new equipment. Contingencies also cover "known unknowns," such as deviations from projected inflation or currency exchange rates, abnormal seasonal weather affecting construction schedules, and variances in commodity prices. AEP estimated fully-loaded costs for each wastewater that it evaluated.

2. **EPA needs to acknowledge agency precedent in ELG revisions and account for minimal pollutant removal rates when assessing cost effectiveness.**

As noted in the comments filed by UWAG,[3] EPA has, in the past, adopted a minimum acceptable average removal rate across a technology option when determining which parameters might be assigned a regulatory limit. For the Centralized Waste Treatment (CWT) ELG finalized in 2000, 65 FR 81241)[4] EPA adopted a minimum removal of 50% for inorganic parameters such as metals (removed by chemical precipitation) and a 30% removal rate for trace organic parameters. The more recent Metal Products and Machinery rule also set a limit for effective removal of 20%. If the removal across a technology option was less than these values, EPA considered the treatment technology ineffective for that parameter.

EPA has developed guidance to use as the basis for eliminating pollutants from treatment consideration. Among these guidelines, EPA did not consider pollutants for TWPE calculations if they were, "not effectively treated by the option technology."[5] Based on this guidance, boron, cyanide, magnesium and manganese may need to be eliminated from consideration during TWPE calculations for chemical precipitation.

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[3] Comments of the Utility Water Act Group (UWAG) on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (40 CFR Part 423) [hereinafter UWAG ELG Comments], September 20, 2013.

[4] Cost-Effectiveness Analysis of Effluent Limitation Guidelines and Standards for the Centralized Waste Treatment Industry, at 2-2, cited by UWAG
http://water.epa.gov/scitech/wastetech/guide/treatment/upload/2006_12_28_guide_cwt_final_effective.pdf

[5] Id.

In following UWAG's recommendation, any pollutant with a removal rate of less than 25% should not be considered during TWPE calculations. There are several reasons why a minimum level of removal must be demonstrated before a treatment system can be credited with successful treatment. For example, analytical variability can complicate the comparison of duplicate samples. Typical quality control standards for reproducibility require that the relative percent difference between sample results be less than 20%. Therefore, it is possible that if the percent removal value calculated from a single pair of influent and effluent samples from the same treatment system is 20% or less, it could be due to simple analytical variability and not due to treatment system removal.

It is also unlikely that any two "paired" influent/effluent samples will actually represent the wastewater that was treated. The retention time and mixing pathways within a treatment system vary, making it almost impossible to collect effluent samples that perfectly match previously collected influent samples. As a result, small percentage differences between "paired" samples may be an artifact of the sampling.

Based on general wastewater engineering practice, percent removals of less than 30% are considered poor and 50% removal is often considered marginal.[6] The inclusion of pollutants whose removal has not been sufficiently verified can lower the dollars per toxic weighted pollutant equivalent ($/TWPE) removed estimates, giving the appearance of more favorable cost effectiveness than actually exists for the proposed treatment technology.

3. Shorter annualization and cost recovery periods need to be considered in the proposed rule.

The time period assumed for cost recovery is a primary consideration when the cost effectiveness of any new technology installation is evaluated. EPA assumes that costs are

[6] UWAG ELG Comments, September 20, 2013, at 101.

annualized over a 20-year period. but has previously used a 15-year period to develop ELGs for other industry categories. UWAG believes. and AEP agrees, that an annualization period based on a 15-year service life is a more appropriate assumption and is consistent with past EPA practice.

The application of the proposed wastewater treatment technologies will require the installation of major equipment, such as tanks. clarifiers. etc.. which should last 20 years. <u>but not without significant maintenance</u>. Motors, gear boxes, linings/coatings, biological substrates, etc., will all need to be replaced or rebuilt over the 20-year time period. Higher energy components, such as pumps and agitators, will also need to be rebuilt or replaced. In other words, the assumption of a 20-year service life for the proposed treatment technologies is not feasible. A shorter cost recovery period. such as 15 years. is more realistic. Market conditions. technological developments. and changing regulations simply do not allow a longer cost recovery period.

4. AEP's Cost Effectiveness Analysis

AEP used the same methods as EPA to determine $/TWPE removed for each assessed wastewater; however, to simplify the analysis, only direct capital costs were used. Capital costs were determined based on actual installations, engineering studies, or best professional judgment. In all cases. the costs were converted to 2010$ and then to 1981$ using *Engineering News Record's* Construction Cost Index (CCI) as follows:[7]

$$\text{Adjustment factor} - CCI_{1981}/CCI_{2010} = 3535/8802 = 0.042$$

[7] EPA Regulatory Impact Analysis, Appendix D: Cost Effectiveness, April 19, 2013.

Like the agency, AEP used a 7% interest value and assumed a 20-year service life when annualizing costs estimates, but notes that use of a 15-year service life would be more appropriate.

In most cases, AEP's $/TWPE estimates were higher than those estimated by EPA, sometimes much higher, despite the fact that EPA also included O&M expenses in its estimates. As a result, the cost differences highlighted in these comments will actually be much larger should the proposed ELG revisions be adopted by the agency. To fully assess the impact of the additional O&M expenses, AEP encourages the agency to refer to the comments of UWAG[8] and EPRI.[9]

C. Proposed Regulation

1. **EPA should independently present all treatment technologies for each individual wastewater stream and dispense with the "bundling" of the proposed treatment options.**

EPA is proposing to revise or establish BAT[10], BADCT (NSPS)[11], PSES[12], and PSNS[13] standards that may apply to discharges of seven waste streams: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate, nonchemical metal cleaning wastes and wastewater from FGMC systems and gasification systems. In this proposal, EPA is presenting eight main regulatory options (Option 1, Option 3a, Option 2, Option 3b, Option 3, Option 4a, Option 4, and Option 5). Four of these options (Options 3a, 3b, 3, and 4a)

[8] UWAG ELG Comments, September 20, 2013.

[9] Electric Power Research Institute (EPRI) Comments on Proposed Effluent Limitations Guidelines Rule [hereinafter EPRI ELG Comments], September 20, 2013.

[10] BAT - Best available technology economically achievable, as defined by Sections 301(b)(2)(A) and 304(b)(2)(B) of the CWA.

[11] BADCT (NSPS) - Best Available Demonstrated Control Technology (New Source Performance Standards)

[12] PSES - Pretreatment Standards for Existing Sources.

[13] PSNS - Pretreatment Standards for New Sources.

are preferred by the agency and one (Option 4a) is the basis of the proposed rule; however, it is very difficult to assess the impact of multiple option proposals. As a result, AEP believes that it must assess and comment on all of the options, but must also make numerous assumptions regarding which option or combination of options may affect the company. It is recommended that in future proposals, EPA evaluate the various options and select a single option upon which to base its proposal. Doing so would allow for the submittal of comments that are more directed and specific to the proposed changes.

Within each option, EPA proposes various technology options for each of the seven waste streams. Each option varies from the other based on which technologies are proposed for each waste stream. Often, this difference varies by only one technology proposal across the seven waste streams. For example, Options 4 and 5 are identical except that EPA proposes ZLD (vapor compression evaporation) for FGD wastewaters under Option 5 in lieu of biological treatment under Option 4. The problem with this proposal format is that the agency has "bundled" the technologies, limiting their application to power plants. Many, if not most, power plants generate at least five of the seven waste streams that are the focus of this rulemaking. The application of any given technology to a specific waste stream should not be limited by the technology that is proposed for another waste stream at that same facility. By "bundling" the technology options, the agency has limited the flexibility of the technology applications. For example, depending on the wastewater generated by a given facility, it may be better to consider chemical precipitation followed by biological treatment for FGD wastewater and to propose impoundments for the remaining facility wastewaters. This particular combination of technologies has not been proposed by the agency due to its unconventional presentation of the technology options. AEP encourages EPA to independently present all treatment technologies for each wastewater stream and to dispense with the "bundling" of the proposed treatment options.

EPA performed a cost-effectiveness analysis of the regulatory options for existing plants and presented the results in the *Federal Register* notice. However, while the agency conducted the same analysis for each individual wastewater, it only presented the results for those technologies proposed under Option 3a, one of the least stringent options (78 FR at 34474). To allow for a more comprehensive comparison of the cost-effectiveness of the proposed treatment technologies, EPA needs to present the $/TWPE for each option on a wastewater-specific basis. For example, when assessing the $/TWPE for FGD wastewater, the agency should present the cost effectiveness information for chemical precipitation only, for chemical precipitation plus biological treatment, for chemical precipitation plus zero liquid discharge, for biological treatment only, and for zero liquid discharge only. This would allow for a better comparison of the cost effectiveness of the proposed treatment options.

While the agency proposal focuses on seven waste streams, AEP has submitted comments that address five of the seven. AEP does not generate wastewater from FGMC or gasification systems; therefore, our comments are limited to FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate and nonchemical metal cleaning wastes.

2. FGD Wastewater

EPA has proposed several different options for the treatment of flue gas desulfurization (FGD) wastewater (78 FR at 34458). Under Option1, physical/chemical treatment, employing hydroxide precipitation, iron coprecipitation and sulfide precipitation, is the basis of the proposed effluent limitations and standards for FGD wastewater. Under Options 2, 3b (for facilities with a total wet-scrubbed capacity of 2,000 MW or more), 3, 4a, and 4, the same physical/chemical treatment is the basis of the proposed effluent limitations, but it is to be used in combination with anoxic/anaerobic biological treatment optimized to remove selenium. Under Option 5, chemical precipitation/coprecipitation, in combination with vapor compression evaporation, is the basis of the proposed limitations and standards. Under Option 3a, EPA is proposing that states use best professional judgment (BPJ) to make technology determinations. BPJ, as proposed under Option 3a, is not an effective regulatory strategy. Under the Hanlon memo[14], states may require biological treatment, which is not a preferred treatment technology under Options 1 and 3a. This also forces states to make technology assessments for which they may not have sufficient technical expertise to conduct, and seems to allow EPA to abdicate a core responsibility under § 304 of the CWA. Of the eight proposed options, three of the four preferred by the agency promote chemical precipitation in combination with biological treatment (Options 3b, 3, and 4a). AEP has concerns with all of the proposed options; however, Option 1 (chemical precipitation) comes closest to meeting the regulatory test of best available technology for FGD wastewater.

a. Rationale for the Proposed Best Available Technology to Treat FGD Wastewater

According to EPA, "Best Available Technology (BAT) represents the best available economically achievable performance of facilities in an industrial subcategory." (78 FR at 34468). After considering all of the technologies available for the treatment of FGD wastewater, the agency is proposing to establish the following options:

- Site-specific limits (BPJ)
- Numeric limits for mercury and arsenic that would require chemical precipitation,

[14] Memorandum from James A. Hanlon, EPA Office of Water, to EPA Water Division Directors, June 7, 2010.

- Numeric limits for mercury, arsenic, selenium and nitrate-nitrite that would require chemical precipitation in combination with biological treatment, and
- Limits that would require chemical precipitation in combination with evaporation.

The agency feels that the first three options are technologically available and well demonstrated, but it does recognize that there are concerns with the feasibility of biological treatment (78 FR at 34470).

EPA also assessed the projected economic impacts of the eight regulatory options, seven of which include chemical precipitation of FGD wastewater and four of which include biological treatment. As part of this analysis, the agency determined that "very few entities are likely to face economic impacts at any level for any of the four preferred BAT and PSES options (Options 3a, 3b, 3, and 4a)" (78 FR at 34495). Three of these options (3b, 3, and 4) include chemical precipitation of FGD wastewater in combination with biological treatment.

Despite the efforts of the agency to assess the costs and economic impacts of the proposed FGD wastewater treatment technologies, AEP found the agency's estimated costs to be well below those based on its own actual facility installations. The specific reasons for this discrepancy are not readily apparent, but several possibilities are provided in the following discussion.

b. EPA cost estimates for chemical precipitation and biological treatment of FGD wastewaters need to be more reflective of actual industry costs.

As described in the ELG TDD, "EPA estimated the chemical precipitation, biological treatment, and vapor-compression evaporation system costs separately, and then summed the costs generated by the appropriate technology cost modules to achieve the total technology option costs (i.e., the chemical precipitation costs were added to the biological treatment and vapor-compression evaporation costs to calculate the total costs for the technology option."[15] The agency then presented the results of its analysis to determine the incremental costs and pollutant removals for each of the proposed technologies.[16] A portion of these results are presented below, along with similar data collected for several AEP FGD wastewater treatment facilities (Table 1).

The results of AEP's own analysis of the capital cost of FGD wastewater treatment installation varied greatly from those of EPA. AEP's costs are based on the actual installations of five chemical precipitation facilities that have occurred within the past six years. These installations all include a cold lime softening, ferric chloride addition, pH adjustment, organosulfide addition, and a variety of coagulating/flocculating polymers to enhance settling. All have a combination of flow equalization tanks, softening tanks, primary and secondary

Table 1. Estimated industry and company-level costs for FGD wastewater treatment (excludes oil-fired and units < 50 MWs).

Technology Option	EPA Capital Cost per Plant (2010$)	AEP Capital Cost per Plant (2010$)	ΔAEP-EPA (2010$)	Percent Increase
Chemical precipitation	$12,500,000	$38,528,164	$26,028,164	208%
Biological treatment*	$9,051,724	$22,299,874	$13,248,150	146%
Chemical precipitation plus biological treatment	$21,551,724	$58,620,327	$37,068,603	171%
Chemical precipitation plus biological treatment#	$35,294,118#	$47,336,433#	$12,042,315	34%

* Difference between chemical precipitation and chemical precipitation plus biological treatment.
\# Plants with total wet scrubbed capacity < 2000MW.

clarifiers, filter presses, and the ability to recycle a portion of the solids. All costs have been converted to 2010$. In all cases, AEP's capital cost estimates are significantly higher than what

[15] EPA Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-13-002, [hereinafter EPA Technical Development Document], April 2013, at 9-19.
[16] Id., Tables 9-3 and 9-4

was presented by EPA. These differences are enough to raise concern about the accuracy of the EPA estimates. In addition, the EPA estimates were used as the basis for the cost effectiveness and $/TWPE analyses, which will be biased towards the low side based on the agency's unrealistically low values.

c. Justification for the 2000 MW threshold total wet scrubbed capacity for the FGD wastewater treatment exemption is needed.

Under Option 3b, EPA has proposed an exemption from biological treatment for facilities with less than 2000 MW of total wet scrubbed capacity. The agency did not provide any information regarding the basis of this proposed treatment threshold but it did provide specific costs for these facilities (Table 1). On average, EPA estimated that it would cost $35,294,118 in capital costs (2010$) to install chemical precipitation and biological treatment at a single facility. After accounting for planned retirements, AEP has two facilities to which this exemption would apply and the capital costs (2010$) for the installation of the proposed treatment technologies have been estimated (Table 1). AEP's estimate is much higher than that provided by EPA, but it does confirm that at least for these facilities, it would cost more on average to install chemical precipitation and biological treatment than at facilities with higher MW ratings. While AEP does not object to the proposed MW threshold for the treatment exemption, it does request that EPA provide the justification for such a threshold.

d. EPA needs to include additional FGD treatment systems besides Allen and Belews Creek in its analysis of FGD wastewater.

EPA has based a significant portion of its FGD wastewater treatment technology analysis on Duke Energy's Allen and Belews Creek Stations, which could be a large factor in the discrepancy between the EPA and AEP capital cost estimates. The FGD wastewater from these facilities is not representative of that generated by the majority of the industry. They are owned and operated by the same company. burn similar coals and use the same operating systems and therefore do not adequately represent the range of facility operations across the country. AEP and its partners own and operate six such facilities, but only two were considered when the agency was developing the proposed ELG revisions. FGD treatment system data from a variety of facilities, which burn different coals and are operated using different practices. need to be incorporated into the agency's analysis.

e. **Additional wastewater characterization and treatment performance data need to be included in the EPA FGD wastewater treatment cost effectiveness analysis.**

EPA calculated $/TWPE removed for the various FGD options (Table 2). EPA determined that "the cost effectiveness of chemical precipitation alone is $70 per TWPE removed. with the cost effectiveness of chemical precipitation plus anaerobic biological treatment...[being] $60 per TWPE removed" (78 FR at 34474). This analysis was based primarily on two power plants, Duke Energy's Belews Creek and Allen Stations. This is not a sufficient database upon which to base the cost effectiveness of such an important treatment technology proposal across an entire industry, and could explain why the results of EPA's analysis differ in respect to those of the AEP analysis.

Table 2. Estimated industry and company-level $ per TWPE removed for FGD wastewater treatment (excludes oil-fired and units < 50 MWs).

Technology Option	**EPA $/TWPE (1981$) 20-yr**	**AEP $/TWPE (1981$) 20-yr**
Chemical precipitation	$70	$30 - $126
Chemical precipitation plus biological treatment	$60	$580 - $1208
Biological treatment	---	$550 - $1082
Chemical precipitation following settling	$70	$341 - $1791

AEP conducted a similar analysis for five of its plants based on cost data submitted to EPA as part of the AEP ELG ICR response or, for more recent projects, the actual installation costs. All cost data were adjusted to 2010$ using RS Means Historical Cost Indices. As done by EPA, costs were annualized over a 20-year period using a 7% annual inflation rate. Excepting the biological treatment options for which EPA did not provide an estimate, AEP's cost estimates are one to two orders of magnitude higher than those of EPA.

Flow data were obtained from the AEP ELG Information Collection Request (ICR) responses (2010) or from AEP operational or environmental data records. Samples were collected from the inlet and outlet of the FGD wastewater physical-chemical and biological treatment systems at AEP plants and analyzed using EPA Methods 200.7, 200.8, 1631E (mercury) and SM20 4500NO3H (nitrate-nitrite as N). Pollutants that were not removed with an efficiency of at least 25% were deleted from the analysis. Typically, these pollutants were boron, magnesium, potassium, sodium or other pollutants that were not effectively removed by the treatment technology.

While AEP's analysis confirmed that, based on past ELG rulemakings, the proposed chemical precipitation technology may be cost effective, EPA's cost effective analysis results were much lower than those calculated by AEP for biological treatment. Based on a 20-year cost recovery period at a 7% annual inflation, AEP's estimates for chemical precipitation plus biological treatment were much greater than those of EPA. These are very significant differences illustrating that EPA's cost effectiveness analysis is biased low and does not account for the true costs of the proposed technologies.

f. **The incremental benefit of chemical precipitation following surface impoundment treatment is not cost effective.**

EPA identified 117 plants that operate wet FGD systems and discharge FGD wastewater. Of these, EPA categorized 47 plants as operating a treatment system more advanced than a surface impoundment. Therefore, up to 70 plants operate impoundments to treat this wastewater.[17] As part of its FGD wastewater treatment evaluation, EPA assumed that plants with such surface impoundments would install one-stage chemical precipitation treatment systems to meet the effluent requirements associated with this option.[18] Therefore, EPA estimated its $/TWPE under the assumption that the wastewater entering the chemical precipitation system had been "treated" with an existing surface impoundment prior to chemical precipitation.

AEP does not operate settling ponds upstream of its FGD wastewater treatment facilities, but it was possible to simulate this treatment to obtain $/TWPE estimates. Surface impoundments effectively remove pollutants in the particulate phase, but are generally ineffective in removing dissolved pollutants. Since dissolved metals data were available, AEP was able to use this data in lieu of actual surface impoundment influent data. As with the previous analysis, flow data were obtained from the AEP ELG ICR response or from AEP operational or environmental data records. Since an upstream pond would remove most of the suspended metals before entering a wastewater treatment facility, the treatment plant inlet can be simulated by using AEP's wastewater treatment plant inlet dissolved metals, from which the $/TWPE can be determined. Samples were collected from the inlet and outlet of the FGD wastewater physical-chemical system; however, the inlet samples were analyzed for dissolved

[17] Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; EPA, April 2013, at 10-5.

[18] Id. at 10-10.

metals, while the outlet metals were analyzed for total metals, using EPA Methods 200.7, 200.8, 1631E (mercury) and SM20 4500NO3H (nitrate-nitrite). Pollutants that were not removed with an efficiency of at least 25% were deleted from the analysis. All cost data were adjusted to 2010$ using RS Means Historical Cost Indices and, as done by EPA, costs were annualized over a 20-year period using a 7% annual inflation rate.

As with the chemical precipitation analysis, the EPA assumption of settling pond use prior to chemical precipitation, generated cost effectiveness values much higher than those obtained by EPA (Table 2). The values based on a 20-year annualization period ranged from $341 to $1791 and averaged $808 per TWPE removed, which is well above what is considered to be cost effective. When presented as fully loaded costs based on a 15-year annualization period, the $/TWPE removed ranged from $494 to $2608 and averaged $1175. Likewise, these values are not cost effective and illustrate that if a settling pond is used prior to chemical precipitation, the incremental benefit in pollutant removal is not cost effective. These cost differences would be even larger if O&M expenses had been included in the analysis.

g. EPA needs to consider the variability of FGD wastewater treatment performance.

There are a number of concerns with the performance of chemical precipitation processes. Large volumes of water (long residence times) are used in the treatment process and failure of a single component (agitator, rake mechanism, feed pump) can incapacitate the process for up to 7 days. Significant changes in the quality of the coal and limestone also occur and the operating conditions of the boiler vary, all of which can affect the FGD wastewater influent quality and have an impact on system performance.

EPA data for arsenic (As) removal in the FGD wastewater treatment process appear based upon limestone, forced-oxidation FGDs. AEP data indicates that majority (up to 97%) of

As is oxidized and in the solid state. This compares to the inhibited oxidized FGDs where the As is predominately dissolved. AEP data indicate that the chemical precipitation process is very effective at removing suspended arsenic, but not at removing dissolved arsenic. As such, there should be further clarification relative to the form of a metal or metalloid species that can be effectively removed in a given process. As with any process, the influent conditions can affect the process performance, particularly that of biological systems. This can be a significant issue when a unit is returned to service after an extended outage. AEP experienced such a condition when returning a unit to service after an extended outage and it took the selenium removal process over a week to recover. This was probably due to the effect the long outage had on the microbes and the time it took to stabilize the FGD chemistry. AEP bioreactor experience is with an FGD that operates at an ORP of 150-200mv, and as such, controlling the ORP of the bioreactor to -150mv is accomplished relatively easily. However, a number of FGDs operate at high ORP levels and reduction to the bioreactor's ORP to -150mv would be more difficult and costly.

h. Impact of ELGs on Water Quality Trading

The proposed ELG rule identifies nitrate/nitrite as a pollutant of concern, which, according to EPA, is simultaneously reduced when applying biological treatment for the control of selenium.[19] Within the proposed rule, EPA lists four preferred options (4a, 3, 3b, 3a). Three of the four, 4a, 3 and 3b, include FGD waste water limits for nitrate/nitrite for steam electric generating plants greater than 2000 MW total scrubbed capacity. A third option, 3a, includes a BPJ determination for FGD nitrate/nitrite limits.

[19] EPA Technical Development Document, April 2013, at 8-7.

Under the proposed rule, the options that include limits on nitrate/nitrite also include limits for selenium based on biological treatment. Because nitrate/nitrite is incidentally removed by the treatment process that removes selenium. EPA does not expect the rule to create a demand by regulated entities for trading in nitrogen credits. In fact, the proposed nitrate/nitrite limits preclude the use of water quality trading as a compliance strategy. However, the agency assumes that biological treatment will remove nitrate/nitrite and selenium in an equally effective manner, while in fact, such treatment systems need to be optimized for one pollutant or the other in order to achieve satisfactory removal.

Even if it is assumed that biological treatment is a cost effective technology for removing selenium, it is certainly not cost effective for the removal of nitrate/nitrite. Based on a business case study done by Keiser and Associates for EPRI,[20] it was demonstrated that total nitrogen (TN) removal to meet nutrient standards could be accomplished at a cost of $2 to $8 per pound or at a cost of approximately $100,000 per year for a typical power plant. However, according to EPA, to achieve similar control of nitrate/nitrite using a bioreactor would cost similarly sized power plants approximately $9.05 million in capital costs and approximately $543,000 in annual O&M (2010$).[21] AEP's own estimates, which are based on an actual installation and are more accurate than those of the agency, include capital costs of $22.3 million (2010$).

Not only is biological treatment vastly more expensive than water quality trading, it achieves a control level which exceeds what is necessary to be protective of water quality. There is no need to control nitrate/nitrite to the low levels proposed by the agency in the ELG rule (0.17 mg/L daily max. and 0.13 mg/L monthly avg.). These levels are much lower than

[20] Ohio River Water Quality Trading Pilot Program: Business Case for Power Company Participation, EPRI Contract No. 125935.4411, Shaw Project Number: 125935, 2008.

[21] EPA Technical Development Document, April 2013.

needed to protect aquatic life or human health and are lower than necessary to prevent the formation of nuisance algae blooms. It would be much more cost effective for the agency to limit biological treatment applications to the control of selenium and to allow water quality trading as a compliance option to achieve any additional nutrient reductions. This approach would allow bioreactor operators to optimize the process to achieve efficient and economical removal of selenium without the additional burden of optimizing for nitrogen control. Even assuming that biological removal is a cost effective technology for the control of selenium, any additional treatment needed to control nitrogen levels should be achieved using the best, most economical treatment strategy, whether that be trading, trickling filters, chemical treatment or biological treatment. Should EPA ultimately determine that biological treatment in combination with chemical precipitation is BAT, it should not establish limits for nitrate/nitrite simply because of the co-benefit of some nutrient reduction while targeting the removal of selenium.

3. Fly Ash Transport Water

EPA is proposing two alternatives for the treatment of fly ash transport water; 1) existing BPT limits, and 2) dry handling (78 FR at 34461). EPA Options 1 and 2 would establish TSS and oil and grease limits that can be met through the use of settling ponds. Under Options 3a, 3b, 3, 4a, 4, and 5, EPA would establish "zero discharge" effluent limitations and standards for discharges of pollutants in fly ash transport water based on the use of dry fly ash handling technologies. The agency's preferred options (3a, 3b, 3, and 4a) all require dry fly ash disposal without the discharge of sluice water.

EPA calculated the cost effectiveness of particular controls for waste streams that would be controlled under the preferred options for existing dischargers. As part of these calculations, EPA provided a cost-effectiveness value of $27/TWPE removed (1981$) for zero discharge of fly ash transport and FGMC wastewater, as proposed in Option 3a. This value cannot be supported by data obtained by AEP, demonstrating that this proposed technology option is not cost effective.

As described in the ELG TDD,[22]

> "EPA estimated compliance costs for plants operating wet sluicing systems to convert to dry vacuum fly ash handling systems. For each generating unit with a wet sluicing system, EPA determined that the plants would likely continue to use the existing valves and branch lines underneath the fly ash collection hoppers, but the plant would require new valves and piping to convey the ash to the silo(s). Additionally, EPA included costs for a mechanical exhauster to create the vacuum. EPA also included costs for the plant to install a new silo, including pugmills and wet unloading equipment. Finally, EPA included costs for the transport and disposal of all the additional ash that the plant is now handling with the dry vacuum system."
>
> "EPA estimated capital, O&M, and 10-year recurring costs associated with converting wet fly ash handling systems (specifically wet fly ash sluicing systems) to dry vacuum fly ash handling systems for steam electric generating units generating fly ash. To estimate compliance costs for a fly ash handling conversion to a dry vacuum system, EPA developed a costing approach for three separate portions of the system:
>
> - **Conveyance.** The portion of the fly ash handling system from the bottom of the collection hopper to the intermediate storage destination that includes the mechanical exhauster, piping, valves, and filter-separators necessary to pull and convey ash from the bottom of the hopper. EPA calculated conveyance costs at the steam electric generating unit level.
>
> - **Intermediate Storage.** The destination to which the dry fly ash is conveyed from the bottom of the hopper. The intermediate storage includes the structure itself (e.g., the silo), including the vacuum equipment necessary to receive the ash from the conveyance lines, and the unloading equipment necessary for moisture conditioning prior to transportation and disposal.[23] EPA calculated intermediate storage costs at the plant level.

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[22] Id., at 9-30.

[23] Plants may have a silo; however, they may need to install the equipment for moisture conditioning ash prior to unloading. Therefore, the intermediate storage costs are based on two cost indicators, one of the silo and one for the pugmill.

- **Transportation/Disposal.** The trucking equipment and operation to move the dry fly ash to its final destination (e.g., on-site or off-site landfill). EPA calculated transport/disposal costs at the plant level."

Based on the above assumptions, EPA determined that only 66 facilities would need to retrofit dry fly ash technologies at a total capital cost of $398 million in 2010$.[24] This translates to a cost of $6.3 million per facility (Table 3). Regardless of the confidence EPA may have in these estimates, they are very much different and much lower than those estimated by AEP.

a. **EPA has under-estimated the cost to retrofit dry fly ash disposal systems and has over-estimated the cost effectiveness of this technology option.**

AEP has two facilities that would be affected by a dry fly ash disposal requirement. The total capital cost to convert both of these facilities to dry disposal would be $198 million (2010$), which is nearly one-half the total cost estimate that EPA obtained for all 66 facilities (Table 3). It is clear that EPA has grossly under-estimated the cost to retrofit dry fly ash systems at power plants. On a per plant basis, the AEP cost is $99 million (2010$), a value that is nearly 16 times higher than that calculated by EPA (Table 3).

Table 3. Estimated industry and company-level costs for dry fly conversion (excludes oil-fired and units < 50 MWs).

EPA Capital Cost per Plant (millions 2010$)	AEP Capital Cost per Plant (millions 2010$)	ΔAEP-EPA (2010$)
$6.3	$98.9	$92.6

EPA has seriously underestimated the cost to retrofit dry fly ash disposal systems. AEP can only speculate that the agency failed to account for costs related to the siting, designing, permitting, and construction of a landfill and the subsequent operating costs for disposal. There are significant costs related to those activities. Establishing a new landfill costs tens of millions

[24] EPA Technical Development Document, April 2013, Table 9-5.

of dollars. Operations involve loading from silos, trucking, placing, spreading and compacting the fly ash. These costs vary, but they are generally in the range of \$3.50-6.00/ ton of conditioned fly ash. In addition to the actual disposal cost, AEP incurs monthly costs regardless of whether 1 ounce or 1000 tons of ash are moved in a month. EPA has inquired about the costs of transporting and disposing fly ash in a privately owned facility and AEP has estimated that those costs are in the range of \$20-30/ton. EPA should not assume that commercial landfill capacity is readily available for plants which must convert to dry handling. Due to hauling distances, associated transportation costs, and competition with other waste generators, many plants will be forced to construct their own captive landfills.

EPA estimated that dry handling of fly ash would cost only \$27/TWPE (78 FR at 34474). EPA based this estimate, in part, on fly ash samples collected from an AEP fly ash pond as part of the agency's Detailed Study sample program, conducted during October 2007.[25]

Using the same methods as EPA to determine \$/TWPE removed for fly ash transport water, AEP calculated values very much different than those determined by the agency. Split samples were collected by UWAG at the same time as those collected by EPA during the Detailed Study program. These samples were analyzed separately for metals and inorganics using EPA methods 200.8 and 200.7 and the results were shared with AEP. Information on the frequency and duration of transport water flow was obtained from the EPA ELG ICR response. Using the cost data presented above, which were adjusted from 2010\$ to 1981\$ using *Engineering News Record's* Construction Cost Index (CCI) and annualized over a 20-year period, AEP determined a \$/TWPE value of \$312 (Table 4); an estimate very much higher than the EPA \$/TWPE value for this waste stream.

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[25] Final Sampling Episode Report, Buckeye Power Company's Cardinal Power Plant, Briliant, Ohio. Sampling Episode 6551. Prepared for USEPA by ERG, Inc., August 2008.

Table 4. **Estimated industry and company-level \$ per TWPE removed for dry fly ash retrofit (excludes oil-fired and units < 50 MWs).**

Data Source	Technology Option	\$/TWPE (1981\$) 20-yr
EPA	Dry fly ash retrofit	\$27
AEP	Dry fly ash retrofit – Plant 1	\$312
AEP	Dry fly ash retrofit – Plant 2	\$208

Like EPA's capital cost estimates, the AEP estimates include total costs to the plant, including major equipment installation, contractor's costs, site work, concrete, piping, electrical, mechanical, engineering, as well as vendor overhead and profit. Regardless, these are still all direct costs and do not include indirect and other costs associated with "fully loaded" estimates, which are the full costs that will be borne by the company's customers.

The \$/TWPE values only include capital costs and do not include annual O&M expenses, transportation costs, disposal costs, etc., which can be substantial. The actual \$/TWPE will be much higher.

Source water to the fly ash pond is a major contributor to the TWPEs for the wastewater discharge. Any fly ash transport water TWPEs need to be adjusted to account for these background pollutants. Without the adjustment for pollutants already present in the intake water, the TWPE calculations penalize power plants for pollutants already present in the water (such as iron and aluminum which are commonly associated with silt and sediment). The TWPE calculation is distorted by the significant amount of intake pollutants and the resultant \$/TWPE value is greatly reduced.

EPA also does not account for changes to the plant water balance due to the loss of the fly ash pond. Many fly ash ponds are used to treat other waste streams generated at a power plant. For example, low volume wastes, storm water runoff, treated FGD wastewaters, coal pile runoff and other waste streams are directed to fly ash ponds for further treatment through settling. AEP estimates to alter the water balance for the plant in question (Plant 1) are \$10 million (2010$). This estimate is based on the assumption that all wastewater that would have been treated in the associated fly ash pond must now be treated with the technology equivalent of a municipal treatment plant (coagulation/flocculation, settling and filtration, less disinfection and specialty treatments, i.e. manganese removal or softening).

After adjusting for fully loaded costs, intake pollutants, a 15-year service life and the costs associated with plant water balance changes, the $/TWPE for this particular plant rose from $312/TWPE to $514/TWPE (Table 4); a significant increase that exceeds the $404/TWPE threshold that EPA considers to be cost effective. As a result, a dry fly ash conversion is not cost effective for this facility.

Using the same procedures as described above, AEP estimated the $/TWPE for a dry fly ash conversion at another of its power plants (Plant 2, Table 4). Using the same assumptions and methods described above, the $/TWPE calculated for this facility was $208. After adjusting for fully-loaded costs, intake pollutants, a 15-year service life and the costs associated with plant water balance changes, which exceeded $17 million in 2010$, the $/TWPE for this particular plant increased from $208 to $383/TWPE; a significant increase that while not exceeding the $404/TWPE threshold that EPA considers to be cost effective, clearly illustrates that EPA did not account for all of the costs associated with dry fly ash retrofits.

b. The ELG revisions should allow for a "dense slurry" option to transport fly ash.

EPA should allow the use of the "dense slurry option" for transporting fly ash. Also known as the GEHO® High Concentration Slurry Disposal Process, this technology includes the use of a much higher ash:water ratio and specialized pumps to transport the fly ash to the disposal area. Due to the pozzolanic/cementitious properties of the minor ash additives, such as lime, the transport water is consumed chemically and little, if any, transport wastewater is generated. Large ash ponds are not created when this technology is utilized as there is no free water emanating from the solidified ash. Storm water issues may still need to be addressed, but they would be no different than those encountered with traditional dry fly ash landfills. In some situations, a roof would be installed over the ash dewatering areas to prevent the disruption of the stabilization process during rain events. After dewatering, the fly ash would be managed in the same manner as is done at traditional fly ash landfills.

c. The construction of new landfills to account for the loss of fly ash ponds would be costly and time-consuming.

In order to accommodate the loss of fly ash ponds, new landfills will have to be built. The time to develop a landfill is site-specific but based on AEP experience, a realistic time period to site, engineer/design, permit, and construct a landfill is on the order of four to six years, longer if land has to be acquired and/or public opposition is encountered. This includes six months for siting, 12 to 18 months for engineering/design, 18 to 30 months for permitting, and 12 to 36 months for construction of the first cell and agency approval to begin disposal.

d. State requirements may necessitate the accelerated closure of fly ash ponds that are no longer used for CCR disposal.

Following the cessation of fly ash sluicing at facilities that convert to "dry" systems, there would be no further use for the ponds. As a result, the proposed CCR rules will take regulatory precedence and under these rules, closure of the unused ponds must begin within 30 days from the last known receipt of CCR material and be completed within 180 days of the start of closure activities (75 FR at 35252-35253), an unrealistic expectation, but not addressed by the ELG rule proposal. This accelerated schedule will incur additional costs for the affected companies that have not been accounted for by EPA.

4. Bottom Ash Transport Water

In five of the eight technology options, EPA is proposing effluent limitations and standards for bottom ash transport water that would be set equal to the current BPT effluent limitations, which are based on settling in surface impoundments. Under the three remaining options, EPA is proposing "zero discharge" based on either using bottom ash handling technologies that do not require transport water, or managing a wet-sluicing bottom ash handling system that does not discharge transport water or pollutants associated with the transport water. Of these three options, Option 4a includes a ≤400 MW per unit exemption.

Mechanical drag systems are considered an available technology that may be used to achieve the proposed limitations and standards under Options 4a, 4, and 5. Other technologies serving as the basis for the proposed limitations and standards are completely dry bottom ash systems, remote mechanical drag systems, and impoundment-based systems that are managed to eliminate the discharge of all bottom ash transport water and any associated pollutants.

a. Bottom ash transport water limits that are attainable with treatment in a settling pond and are consistent with the current BPT limits, are cost effective and protective of the environment.

Options 1 through 3, as well as Options 3a and 3b, which would establish bottom ash transport water limits that are attainable with treatment in a settling pond and would be consistent with the current BPT limits for this wastewater are cost effective and sufficiently protective of the environment. This conclusion is based on the small contribution of pollutants from this waste stream and the high costs of treatment, based on $/TWPE removed.

b. EPA has underestimated the cost of dry bottom ash conversions.

For the proposed revisions to the steam electric effluent guidelines, EPA performed a cost-effectiveness analysis, but did not present the results on an individual waste stream basis. Instead, the results were presented as a sum of all the waste streams for a given regulatory option

(78 FR at 34504). However, EPA did use data provided by a single vendor, Clyde Bergemann Power Group to develop bottom ash retrofit costs (see EPA-HQ-OW-2009-0818-2007). EPA generated a cost curve for three different mechanical drag systems; a remote submerged scraper conveyor system, a completely dry, sub-boiler ash system, and a sub-boiler bottom ash system that only uses water for quenching bottom ash. Based on the costs for these three systems, EPA developed a linear equation to estimate retrofit costs for bottom ash handling:

$$\text{Unit costs (2010\$)} = 20{,}083 \times \text{capacity (MW)} + 3{,}000{,}000$$

AEP compared its costs to retrofit dry bottom ash systems with those estimated by EPA. Twelve AEP facilities were included in the evaluation and each was assigned to one of three groups based on gross MW capacity (>2000, 1000 to 2000, < 1000). Within each group, the direct capital cost to retrofit a dry bottom ash system was estimated in 2010$ using both the EPA linear equation above and an AEP estimated retrofit cost of $31.54/kW (2011$) for the installation of a remote submerged chain conveyor or a recirculation system utilizing dewatering bins. The direct cost estimates include contingencies to cover difficult installation with limited acreage for installing equipment. Contingencies also cover "known unknowns," such as deviations from projected inflation or currency exchange rates, abnormal seasonal weather affecting construction schedules, and variances in commodity prices. AEP's price estimate includes all equipment needed for the installation; tanks, pumps, piping and valving. Fully-loaded costs were also estimated for each group.

Based on the EPA equation, such a retrofit was estimated to cost $57.2 million (2010$) for a plant greater than 2000MW, a value well belowAEP's direct cost estimate of $82.7 million (Table 5). On a fully-loaded basis, the AEP estimate for this size power plant is $105.34 million, almost double the EPA estimate.

Table 5. Capital Cost Comparisons to Retrofit Dry Bottom Ash Systems (in millions of 2010 $).

MW (gross) Ranges	Number of facilities	EPA estimate (avg)	AEP estimate (avg)
> 2000	3	$57.2	$82.7
1000-2000	7	$32.4	$42.5
< 1000	2	$18.3	$22.5

* Assumes no 400 MW per unit threshold exemption

Comparisons between the MW groupings further illustrate the large discrepancy between the AEP and EPA cost estimates (Table 5). On average, AEP's cost estimates are 23% to 44% higher than those of EPA on a direct cost basis and 54% to 84% higher on a fully-loaded basis. These differences are significant and compromise any conclusions regarding the cost effectiveness of dry bottom ash retrofits.

c. **AEP's $/TWPE removal estimates demonstrate that the regulation of bottom ash transport water, as proposed in the agency's effluent guidelines revisions, is not cost effective.**

EPA performed a cost-effectiveness analysis for all the proposed technologies and in the case of bottom ash transport water, estimated $/TWPE removed values of $107 and $99 (1981$).[26] Since EPA has found, and AEP agrees, that a cost of $404 (1981$) per TWPE removed is acceptable, these values appear to be reasonable, however, they are misleading because they are unrealistically low.

Using the same methods as EPA to determine $/TWPE removed for bottom ash transport water, AEP calculated values which are very much different than those determined by the agency. Water samples were collected from two AEP system bottom ash ponds and the source of ash transport water for each facility. No other waste streams enter either pond. The samples were analyzed for metals and inorganics using EPA methods 200.8 and 200.7. Information on

[26] Cost Effectiveness of Removing Toxic Pollutants for Direct Dischargers at a Waste Stream/Technology Level, EPA-HQ-OW-2009-0819-2255.

the frequency and duration of transport water flow was obtained from the EPA ELG ICR response.

AEP adjusted the compliance costs from 2010$ to 1981$ using *Engineering News Record's* Construction Cost Index (CCI). EPA also used a 7% interest value and assumed a 20-year service life when annualizing costs estimates. AEP did likewise to make the cost comparisons equivalent, but notes that use of a 15-year service life would be more appropriate.

Based on these data and using an annualized direct capital costs in 1981$ for a plant retrofit. AEP determined a $/TWPE value of $16,007 (Table 6); an estimate two orders of magnitude higher than any of the EPA $/TWPE values for this waste stream. The fully-loaded estimated based on a 15-year annualization period is even higher, exceeding $23,000.

Table 6. Estimated industry and company-level $ per TWPE removed for dry bottom ash retrofit (excludes oil-fired and units < 50 MWs).

Data Source	Technology Option	$/TWPE (1981$) 20-yr
EPA	Dry bottom ash retrofit	$99 - $107
AEP	Dry bottom ash retrofit – Plant 1	$16,007
AEP	Dry bottom ash retrofit – Plant 2	$4,961

A blend of bituminous and sub-bituminous coals is burned in sub-critical cyclone-fired wet bottom boilers at the plant in question, so the ash generated by this facility is primarily boiler slag. When the molten slag contacts the quenching water at the bottom of the boiler, it crystallizes, fractures, and forms pellets that have a smooth, glassy appearance. Boiler slag is a very inert material, more so than bottom ash, and contributes very few pollutants to the transport water. As a result, very few TWPEs are removed following a dry bottom ash retrofit and the $/TWPE values are very high. Regardless, EPA has not distinguished between various bottom ash types and should Options 4a, 4, or 5 be adopted, a dry bottom ash conversion would be required for this facility at a cost that is well above that which has been determined by the agency to be reasonable. Additionally, AEP presents costs on a direct basis in these comments for comparison purposes, but a more accurate portrayal of expected compliance costs would be to "fully load" the direct costs with indirect costs, such as company overheads, as well as Allowance for Funds Used During Construction (AFUDC). Fully-loaded costs represent the total amount that will be borne by utility customers as a result of this rule.

To provide another example of the unacceptable cost of dry bottom ash retrofits, AEP provides information collected from a second facility. A bituminous coal is burned at this facility in a sub-critical wet-bottom boiler. Using the same methods as those used to determine $/TWPE removed for the prior facility, values very much different than those determined by the agency were again obtained. Water samples were collected from the bottom ash pond discharge and the source of the transport water. Again, no other waste steams enter the pond. The samples were analyzed for metals and inorganics using EPA methods 200.8 and 200.7. Information on the frequency and duration of transport water flow was recorded on the day of the sampling. Based on these data and using a 20-year annualization period, AEP estimated a $/TWPE value of $4,961 (1981$); an estimate very much higher than any of the EPA $/TWPE values determined for this waste stream (Table 6). The fully loaded estimate based on a 15-year annualization period is even higher, exceeding $7,200.

There are many reasons why the EPA $/TWPE estimates do not reflect the true cost of dry bottom ash retrofits. Many of these have been highlighted in the UWAG comments[27] and include reliance on a single bottom ash transport water sample, use of data from the 1982 Development Document, which are not representative of today's bottom ash wastewaters and were obtained using outdated analytical techniques, the use of questionable Form 2C data, the use of sulfide data that are likely "false positives," and the inappropriate rounding up of mercury data. AEP endorses the UWAG comments and urges EPA to carefully consider them.

[27] UWAG ELG Comments, September 20, 2013.

AEP's $/TWPE removal estimates , as well as those of UWAG, demonstrate that the regulation of bottom ash transport water, as proposed in the agency's effluent guidelines revisions, is not cost effective. However, the lack of a justifiable cost-benefit analysis is not the only reason to reconsider this proposal. For example, some state regulatory agencies require that ash ponds be closed once wet sluicing is discontinued and the ponds serve no further purpose. For some AEP facilities, the schedule for pond closure would be accelerated, putting further pressure on company budgets that are already stressed. Additionally, some AEP bottom ash retrofits will be tank-based and will not require the use of bottom ash ponds. Since there would be no further use for these particular ponds, the proposed CCR rules will take regulatory precedence. Under these proposed rules, closure of the unused ponds must begin within 30 days of the last receipt of CCR material and be completed within 180 days of the start of closure activities; an unreasonable time requirement that needs to be addressed under the CCR rule.

Loss of these ponds, due to either the proposed effluent guideline revisions or the proposed CCR rule, will have ancillary effects. Most bottom ash ponds are also used to treat low volume wastes through pH control, settling, precipitation, etc. Closure of the ponds due to the proposed effluent guideline and CCR rule changes will require that these ponds be replaced with similar ponds that will not receive coal combustion byproducts. The construction of such ponds will necessitate changes to plant water balances, at significant cost. For example, loss of the bottom ash pond at Plant 2 would require water balance changes in excess of $25 million in direct capital costs (2010$) and over $31.25 million in fully-loaded costs (2010$). At a larger AEP plant, required water balance changes would cost in access of $90 million in direct capital costs (2010$) and over $111 million in fully loaded costs (2010$). At yet another AEP facility, required water balance changes would cost over $95 million in direct capital costs (2010$) and over $118 million in fully-loaded costs (2010$). For the company as a whole, these costs would exceed $931 million (2010$) in direct capital costs and over $1.2 billion in fully-loaded costs (2010$).

d. While a 400 MW threshold for dry bottom ash management may be appropriate, it is entirely possible that a higher threshold is needed to account for additional costs.

EPA has proposed under Option 4a that the "dry" bottom handling requirement be applied to units that are greater than 400 MW (nameplate capacity). Units less than or equal to 400 MW would continue to comply with BPT requirements (surface impoundments). EPA discusses its reasons for this threshold, but does not provide specific information that can be used as the basis for exempting units less than or equal to 400 MW in size. The agency recognizes that the potential costs associated with a zero discharge compliance standard for discharges of bottom ash transport water would be substantial if applied to all facilities (for example, approximately half of Option 4 costs and approximately a third of Option 5 costs) and; therefore, looked carefully at this waste stream with a particular focus on generating unit size. EPA claims that it review demonstrated that, in the case of bottom ash transport water, units less than or equal to 400 MW are more likely to incur compliance costs that are disproportionately higher per MW than those incurred by larger units, but did not provide specific economic information to justify this conclusion. For example, the agency states that "the average annualized cost of achieving zero discharge limits for bottom ash discharges (i.e. dry handling or closed loop) per MW for a 200 MW unit is more than three times higher than the average cost for a 400 MW unit," (78 FR at 34470) but did not provide the data used to make this determination. Furthermore, while EPA incorrectly assumes that all plants, regardless of size, are capable of installing and operating dry handling or closed-loop systems for bottom ash transport water at costs that would be affordable for most plants, it does correctly note that companies may choose to shut down 400 MW and smaller units instead of making new investments to comply with proposed zero discharge bottom ash requirements. This decision is based on a "belief" that since utilities have announced planned retirements or conversions to non-coal based fuel sources, they would not retrofit "dry" bottom ash systems on smaller units (78 FR at 34470). While it may be true that of those units for which utilities have announced retirements, over 90 percent are 400 MW or less (see DCN SE03834), it is still possible that "dry" bottom ash retrofits may contribute to additional plant retirements. EPA fails to note that most of the retirements were announced <u>before</u> the proposed ELG revisions were published in the *Federal Register*.

While EPA believes that a 400 MW threshold may be appropriate based on the reasons specified above, it is entirely possible that a higher threshold is needed to account for the additional cost of the retrofits. However, based on AEP's analysis of the cost effectiveness of "dry" bottom ash retrofits, it does not appear that any retrofit or installation would be cost effective for any size unit.

5. Combustion Residual Leachate

a. ELG Options 1, 3a, 2, 3b, 3 and 4a for the management of combustion residual leachate are cost effective.

Under ELG Options 1, 3a, 2, 3b, 3, and 4a, EPA has proposed effluent limitations for leachate from surface impoundments and landfills containing CCRs that would be set equal to the current BPT effluent limitations. These are based on the technology of gravity settling in surface impoundments to remove suspended solids. Under these proposed options, "leachate" would be removed from the definition of low volume wastes at 40 CFR 423.11 (b) and BAT limits for leachate equal to the current BPT limits for TSS and oil and grease would be established (78 FR at 34463).

Under ELG Options 4 and 5, which are not agency preferred options, EPA is proposing chemical precipitation/coprecipitation, equal to the BAT technology proposed under Option 1 for FGD wastewater. The agency justifies this option on the premise that surface impoundments are not designed to remove dissolved metals; therefore, chemical precipitation is needed for pollutant removal.

AEP encourages EPA to continue to designate leachate as a "low volume waste." Besides noting that surface impoundments are not designed to remove dissolved metals, the agency has provided no reason to distinguish leachate from other low volume wastes.

b. Clarification on the definitions of leachate, contact storm water runoff and noncontact storm water runoff is needed.

EPA defines "leachate" as "the liquid that drains or leaches from a landfill or surface impoundment." The agency notes two sources of leachate – precipitation that percolates through the wastes disposed in a landfill or impoundment and the storm water that enters the impoundment or contacts and flows over the landfill (78 FR at 34450). According to EPA, "leachate and contaminated storm water contain heavy metals and other contaminants through contact with the combustion residuals" (Id.). The agency also notes that leachate and storm water may be treated in separate impoundments or combined together.

EPA has also proposed anti-circumvention provisions that would prevent facilities from circumventing the effluent limitation and standards. The first of these would require, "that compliance with the new effluent limits applicable to a particular waste stream (e.g. FGD, gasification wastewater, leachate) be demonstrated prior to use of the wastewater in another plant process that results in surface water discharge or mixing the treated waste stream with other waste streams" (78 FR at 34465). While not specifically stated, it appears that the agency wishes to eliminate the dilution of wastewater with less polluted wastewater (i.e. noncontact storm water). This implies that noncontact storm water runoff from a covered portion of a landfill could not be commingled with landfill leachate prior to treatment. The agency has not been clear on how it defines noncontact storm water, but should it define noncontact storm water as not being leachate, then the anti-circumvention provision also needs to be revised to accommodate situations where leachate and storm water (both contact and noncontact) are commingled prior to treatment. It is generally not practicable to divert noncontact storm water from landfill runoff ponds that also receive landfill leachate. Portions of a landfill are continually closed and covered, creating new sources of "clean" storm water runoff. The commingling of these water sources prior to treatment should continue to be allowed.

c. Landfill leachate chemical precipitation is not a cost effective treatment technology.

While not a preferred option, EPA did review the cost effectiveness of controlling leachate using chemical precipitation. The agency determined that a $/TWPE removed value for this technology option would exceed $1,000 and would not be cost effective (78 FR at 34474). AEP agrees with this conclusion and provides additional information to support this analysis.

The Electric Power Research Institute (EPRI) estimated the cost effectiveness of treating three different landfill leachates using chemical precipitation.[28] One of these three leachate samples was obtained from an AEP facility. The approximately 1600 MW plant in question burns a bituminous coal and operates a wet FGD (magnesium-lime inhibited and LSFO). The landfill contains predominantly FGD wastes (i.e. FGD pozzolanic material), FGD wastewater treatment plant solids, fly ash, bottom ash, and gypsum. Samples of untreated landfill leachate were collected and analyzed for the same parameters investigated by EPA for the Merrimack

[28] EPRI. Draft Cost/Benefit Analysis for Physical/Chemical Treatment of Landfill Leachate. July 25, 2013.

NPDES permit.[29] Jar treatability studies were conducted using ferric chloride and organosulfide. The majority of the mass removed from the leachate was aluminum, ammonia and molybdenum, while some parameters, such as boron and magnesium, increased in the treated leachate, indicating ineffective treatment.

The capital cost of the chemical precipitation treatment option was estimated to be $10.2 million (2010$). This estimate is based on two treatment trains, each sized at 100 percent peak flow, and assumes one clarifier (primary) per train. Annualized costs were determined using a 20-year equipment "life" at a 7% interest rate. The annualized capital costs for the AEP facility were estimated to be $940 thousand. The estimated $/TWPE removed for this facility was $230,000. Granted, this extraordinary estimate is based on a jar test, but it does confirm EPA's conclusion that chemical precipitation of landfill leachate is not a cost effective technology.

To further illustrate the cost ineffectiveness of proposed chemical precipitation for landfill leachate, AEP collected leachate data from four of its coal-burning facilities. The leachate samples were analyzed using EPA-approved methods (200.8, 200.7, 1631E) to determine total metal and inorganic pollutant levels. Since AEP does not currently treat leachate with chemical precipitation, the methods described in the EPA TDD were used to evaluate the cost effectiveness of this technology. In the TDD, it is stated that,

> "EPA did not identify any plants currently operating a chemical precipitation system to treat landfill leachate. Therefore, EPA transferred the limitations and standards from the FGD chemical precipitation system. Because EPA does not have analytical data that represent treated landfill leachate for the technology options being considered, EPA also transferred the FGD chemical precipitation effluent concentrations, identified in Section 10.2.1, to the landfill leachate for the purposes of calculating post-compliance loadings. In cases where the average concentration of the untreated active or inactive combustion residual landfill leachate is less than the FGD treated concentration for

[29] Merrimack Station NPDES Permit Number NH0001465, Public Service of New Hampshire.

> the technology option, EPA assumed that the treated concentration was equal to the influent (untreated leachate) average concentration."[30]

The results of FGD chemical precipitation, averaged over five AEP plants, were used to evaluate pollutant removal from leachate. The capital cost to install chemical precipitation for leachate treatment at AEP facilities was extrapolated from the EPRI data on the basis of leachate flow. Flow data were obtained from EPA ICR records, actual AEP measurements from 2009-2012, or were estimated. Capital costs were converted to 2010$, then annualized over 20-year and 15-year time periods at a 7% inflation rate.

The $/TWPE removed ranged from $580 to approximately $4 million, clearly illustrating the cost ineffectiveness of this treatment technology for leachate. On a 15-year, fully loaded basis, the costs ranged from $843 to $5.6 million per TWPE. Even eliminating the obvious million-dollar outlier, the $/TWPE values ranged from $843 to $171,000.

Settling ponds for leachate treatment are effective in removing suspended solids and the metals associated with them. The incremental benefit of adding chemical precipitation to this treated effluent is simply not cost effective.

Most of AEP's landfill leachate is collected and either treated on site for pH control or sent to FGD wastewater treatment facilities. Based on the results of EPRI studies,[31] it is possible to estimate a cost for the chemical precipitation treatment of landfill leachate across the AEP system. Based on actual or estimated leachate flow rates, capital costs to install chemical precipitation at existing landfills are estimated to be $528 million in 2010$. While this cost is clearly significant, it is not representative of the total cost of the proposed technology application, since not only would landfill leachate need to be treated, but surface leachate from

[30] EPA Technical Development Document, April 2013, at 10-20.

[31] EPRI ELG Comments, September 20, 2013.

all impoundments and dams would need to be treated. Seepage from AEP impoundments and dams is typically collected using toe drains or slope drain systems. At most locations. the leachate is collected to a central location and discharged directly. Collection of all seepage can be very difficult, if not impossible, at some locations.

As part of its ICR response effort, AEP conducted an inventory of leachate sources throughout its system. Fifty-seven leachate sources and seeps were identified that were not part of existing landfill systems. Based on an average cost of $21 million per chemical precipitation facility, which is a value extrapolated from the EPRI studies and based on flow, it would cost AEP an estimated $1.2 billion to install chemical precipitation treatment for these additional sources of leachate. Granted, these additional leachate sources would likely be commingled and diverted at additional cost and level of difficulty. back to existing or yet-to-be constructed. chemical precipitation facilities, but these calculations illustrate the possible financial burden of the proposed treatment technology.

d. It would not be practicable to install leachate chemical precipitation treatment at remote and retired sites.

AEP operates many remote landfills and leachate ponds that do not have access to power. In addition, AEP has announced the planned retirement of several power plants. Many of these sites operate landfills and impoundments that will need to be closed; however. the leachate from these facilities will continue to flow for many years. If chemical precipitation of the leachate is required by EPA, electric power and staff will have to be provided and dedicated to these sites.

As has already been demonstrated, the chemical precipitation leachate treatment option is not cost effective. The pollutant loading from landfill leachate is not significant. Existing BPT limits and water quality-based effluent limits are sufficient to regulate leachate discharges and protect the environment. The additional expense of implementing chemical precipitation to remote sites that do not have assigned staff or access to electrical power further inhibits the cost effectiveness of this treatment option. AEP encourages EPA to reconsider this option.

6. **Nonchemical Metal Cleaning Wastes**

   a. **Nonchemical metal cleaning wastes should, as EPA proposes, continue to be regulated as low volume wastes.**

For nonchemical metal cleaning wastes, EPA has proposed chemical precipitation as the technology basis for all eight effluent guideline regulatory options. The agency also proposes to preserve the status quo, with BPT (and now BAT) limits of 1.0 mg/L for iron and copper that would be applied to nonchemical metal cleaning wastes (that is, water washes of metal process equipment), but only at those facilities where these limits have been applied in the past. Facilities that currently manage nonchemical metal cleaning wastes as "low volume wastes," subject only to TSS and oil and grease limits, would continue to manage them as low volume wastes.

AEP supports EPA's intent to preserve the status quo for plants that are permitted to discharge nonchemical metal cleaning wastes subject only to TSS and oil and grease limits. However, EPA has proposed methods of implementing the proposed BAT limits that may not preserve the status quo, but would instead require that many existing plants be modified to collect and treat the water washes to meet the 1.0 mg/L iron and copper limits. Much of this confusion lies with how the terms "metal cleaning wastes," "chemical metal cleaning wastes," and "nonchemical metal cleaning wastes," are defined.

EPA defines "metal cleaning waste" as "any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment, including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning" (78 FR at 34464). This definition includes any wastewater generated from either the chemical or nonchemical cleaning of metal process equipment. EPA defines "chemical metal cleaning waste" as "any wastewater resulting from cleaning of any metal process equipment with chemical compounds, including, but not limited to, boiler tube cleaning" (78 FR at 34465). During the earlier development of BAT effluent guidelines for these wastewaters, the term "nonchemical metal cleaning waste" was not defined, but in the EPA proposal, it is defined as "any wastewater resulting from the cleaning of metal process equipment without chemical cleaning compounds" (Id.).

EPA notes in the proposed ELG revisions that BPT limits for discharges of metal cleaning wastes. "which include both chemical and nonchemical metal cleaning wastes," include limits for TSS, oil and grease, copper and iron. While EPA feels that the current BPT limits apply to nonchemical metal cleaning wastes, it has found that some discharges of nonchemical metal cleaning wastes are authorized pursuant to permits that incorporate limitations based on BPT requirements for low volume wastes and are, therefore, not subject to technology-based limits for iron and copper. This exemption becomes the basis of the problem.

EPA believes, and has stated in the proposed revisions, that "discharges of metal cleaning wastes that are generated from cleaning metal process equipment without chemical cleaning compounds (i.e. nonchemical metal cleaning waste) are already subject to BPT effluent limits from copper and iron equal to the BAT effluent limits being proposed today. Based on responses to the industry survey, facilities typically treat both chemical and nonchemical metal cleaning waste in similar fashion" (78 FR at 34471). In the proposed revisions. EPA goes on to state that since "nonchemical metal cleaning waste is included within the definition of metal cleaning waste, and copper and iron are already regulated under metal cleaning wastes, EPA would be establishing BAT limits equal to the BPT limits (for copper and iron) that already apply to these wastes. As a result, facilities should incur no cost to comply with the proposed BAT for these wastes" (Id.). However, these conclusions are simply not true.

b. EPA errs in how chemical and nonchemical metal cleaning wastes are managed.

As explained above, EPA believes that at many facilities, nonchemical metal cleaning wastes are either not discharged or where they are discharged, they are treated the same as "chemical" metal cleaning wastes that use solvents or detergent in the water. In other words, EPA claims that wastewater from all water washes is either not discharged, or, if it is discharged, it is subject to 1.0 mg/L total iron and total copper limits. This conclusion is based on a review by EPA regional offices of 45 NPDES permits for plants that the agency believed had generated nonchemical metal cleaning wastes based on responses to the ELG ICR. Based on this review, EPA determined that:

- Sixty-four percent of the plants either do not discharge metal cleaning wastes or have to comply with effluent limits for copper and iron;
- Permits for 27 percent of the plants do not include effluent limits for copper and iron; and
- Permits for nine percent of the plants do not include enough information to determine whether the plant already operates in a manner that would be in compliance with the proposed BAT limitations (Id.).

EPA then concluded that "many, but not all, plants are either zero discharge or have iron and copper limits and thus are already meeting these proposed BAT limitations" (Id.). However, by assuming that plants are either not discharging nonchemical metal cleaning wastes or already meeting the proposed iron and copper limits, EPA is missing the fact that many plants do discharge these wastes and that the proposed iron and copper limits are not applied. The agency is, therefore, not aware of the potential impact of the proposed BAT limitations for nonchemical metal cleaning wastes.

In the proposed ELG revisions, EPA solicits comments on how metal cleaning waste discharges are referenced in NPDES permits (Id.). AEP conducted a survey of its facility NPDES permits and found that state agencies varied in their application of NPDES regulations to the management and discharge of metal cleaning wastes. For example, permits in Kentucky and Indiana reference the Jordan memo and do not impose iron or copper limits on metal cleaning wastes identified under the "memo." In West Virginia, these wastewaters are regulated as low volume wastes and in Ohio, the wastewaters are referenced in the permits as potential sources of pollutants, but are otherwise regulated as low volume wastes. The results of this internal survey are not exhaustive, but in no case was it found that state agencies enforced technology-based iron and copper limits on non-chemical metal cleaning wastes. However, that does not mean that state agencies conducted evaluations of these wastewaters. It simply confirms that states consider them to be low volume wastes and regulate them as such.

AEP compared its ELG ICR responses to the results of the EPA review referenced above and found discrepancies with the information provided by EPA (Table 7). Three AEP plants are listed (Big Sandy, Lawrenceburg, and Gavin). An ICR was not completed for the Lawrenceburg Plant, but that <u>information is incorrect</u>. For the other two facilities, <u>the EPA information is also incorrect</u>. At both Big Sandy and Gavin, chemical and nonchemical cleanings are performed and the wastewaters are handled differently.

At both facilities, high pressure, nonchemical washes of the fireside of boiler tube airheaters, etc., are typically comingled with bottom ash transport water, cooling tower blowdown, etc., and discharged to surface waters after going through a settling pond (bottom ash pond). Solids are directed to a landfill or impoundment. At the Lawrenceburg facility, chemical washes are disposed of off-site or treated via evaporation. Nonchemical washes are tested for hazardous characteristics and if hazardous, are disposed of off-site. If non-hazardous, they are discharged as low volume wastes. There are no iron or copper technology-based limits, though the Gavin Plant has a copper WQBEL of 50 ug/L (max) on the bottom ash pond discharge. There are no such limits in the Big Sandy NPDES permit for the bottom ash pond and the downstream clear water pond.

For chemical cleanings (waterside boiler tube cleanings, stator cooling system cleanings, condenser tube cleanings), the wastewater is either comingled and treated in a metal cleaning waste tank or is kept isolated and evaporated. The treated water is discharged to surface water through a bottom ash pond after meeting internal iron and copper limits of 1.0 mg/L. The residues are hauled off-site.

In conclusion, when nonchemical metal cleaning washes are generated and discharged, they are handled differently from chemical metal cleaning washes and iron and copper limits are not always applied to the nonchemical metal cleaning wastes.

Table 7. Corrections to EPA ICR records on AEP metal cleaning waste practices.

Plant	**State**	**Permit No.**	**Type of Wash Water Discharged**	**Chemical and Nonchemical Waste Treated Differently?**
Big Sandy	KY	KY0000221	Chemical and Nonchemical	~~No~~ **Yes**
American Electric Power Lawrenceburg	IN	IN0060950	Chemical **and Nonchemical**	**Yes** ~~Disposed of offsite~~
American Electric Power Gavin	OH	OH0028762	Chemical **and Nonchemical**	~~NA; only~~ **Yes** ~~chemical~~

c. **Metal cleaning wastes should be defined as washes of "gas-side process equipment."**

As cited in the UWAG comments,[32] the terms "metal cleaning waste," "chemical metal cleaning wastes," and "boiler chemical cleaning waste" are not clearly defined and are often used synonymously in NPDES permits. These discharges are typically permitted with iron and copper limits if they are associated with chemical cleaning compounds. EPA now seems to interpret "metal cleaning wastes" as all-inclusive, which is not supported by the record. As shown in the following table of the various sources of wash water from cleaning metal process equipment at AEP's plants (Table 8), a literal interpretation of EPA's proposed definition could be overly expansive. We do not believe that it is EPA's intent to regulate the common washing of <u>external</u> surfaces of process equipment or associated structures. Therefore any definition must be limited to the washing of internal surfaces that are in direct contact with the steam generating process. Without additional clarification or analysis by EPA, any definition of nonchemical metal cleaning wastes should be restricted to the gas-side removal of ash without chemicals. AEP agrees with UWAG that expanding the definition of "metal cleaning wastes" to water washing of process equipment *other than gas-side ash removal* would be expensive and of limited environmental benefit. No analytical data or supporting documents have been added to the record to support the proposed expanded (and possibly all-encompassing) definition, which if taken to extremes, could be interpreted to include such benign discharges as intake screen backwash.

As proposed by UWAG, a suitable definition of "nonchemical metal cleaning wastes" would be "any wastewater from the cleaning of ash from gas-side process equipment from the boiler to the stack without chemical cleaning compounds, including boiler fireside cleaning and

[32] UWAG ELG Comments, September 20, 2013, at 268.

air preheater cleaning." Limiting nonchemical metal cleaning wastes to gas-side ash related cleanings is appropriate as the focus of the effluent guidelines is to regulate combustion related processes.

If iron and copper limits are applied, further clarification of nonchemical metal cleaning wastes is critical. The current definition refers to "metal process equipment;" however this is so vague it could be interpreted to apply to essentially any equipment fabricated from metal, such as tanks, coolers, pumps, piping, etc... The list of such equipment at AEP's facilities is quite extensive and currently washes of this equipment are typically handled as low volume wastes and internal iron and copper limits are not applied. Should such limits be applied, as proposed in the revised effluent guidelines, the cost impact, while difficult to determine, is expected to be both extremely significant and onerous. To determine the extent of nonchemical metal cleaning washes at its facilities, based on AEP's interpretation of current nonchemical metal cleaning washes, AEP conducted a survey of all its power plants and found that generation of these wastes is extensive and varied (Table 8).

If iron and copper limits were to apply to wastewater from all of these washes, it would be difficult, and in many cases, impractical to segregate and capture the associated waster. In addition it would be extremely costly to install the necessary equipment to capture, transport and finally treat the wastewater. In summary, further clarification of nonchemical metal cleaning wastes is necessary as the current definition is too broad and could involve many wash processes not intended to be regulated by the effluent guidelines.

Table 8. AEP Nonchemical Metal Cleaning Waste Management

Nonchemical MCW	Treatment	Frequency
Air compressor coils & equipment	power wash or water wash	
Air heater washes	high pressure low volume rinse/low pressure high volume rinse	Once / year
Air preheater washes	high pressure low volume rinse/low pressure high volume rinse	Once / year – 2 years
Ash slurry line washes	High or low pressure flush (as needed) for unplugging	0 - 4 times / year
Bearing water coolers	rotating brush or scrapers	
BFP oil coolers	rotating brush or scrapers	0 to once / year
Boiler external washes		1 – 2 / year
Boiler fireside cleaning	High pressure water wash	Typically every outage of sufficient length (approx. 0 -12 times / year)
Boiler flush/rinse	Water flush / power wash or water wash	0 – 3 / year
Clarifier / Coagulator wash down	power wash or water wash	0 – 1 / year – 2 years
Clarite Filters wash down	Typically with condensate but chemicals could be used	
Closed cooling water heat exchangers	power wash or water wash	0 – 1 / year
Combustion turbine cleaning / wash		
Condenser Cleaning (main, auxiliary)	Flush water / High pressure water / Mechanical scrapers and/or brushes	1 / year – 2 years
Condenser exhauster coolers	rotating brush or scrapers	
Cooling tower suction screens	power wash or water wash	
Deaerator flush/rinse	power wash or water wash	0 – 1 / year
Economizer washes	High pressure water wash	None up 6 – 12 / year
ESP perforated plate	Water wash to remove Trona pluggage	
Evap media cooling/rinsing	water spray	
FGD Absorber vessel washes / rinses		
Filter vessel (gravity, MMF, ion exchange, etc.) cleanings	power wash or water wash	Yearly to 1 / every few years
Filter press rinse / wash	high press. water spray	
Forced-draft fans	wash	
Gas turbine component wash	high press. water spray	1 / year
Gas turbine compressors	power wash or water wash	
Hydrogen coolers	High pressure / low pressure water wash	As needed (0 – 1 / every few years)
LP Section of HRSG	High Pressure H2O or dry Ice	
Mechanical dust collector cleaning	Low pressure / volume water wash	Can be daily
Misc. Heat Exchanger Washes	Water / Scrapers or brushes	As needed (typically 0 /

Nonchemical MCW	Treatment	Frequency
		year)
Mist Eliminator washes	High pressure water wash	As needed to remove scale
Oil coolers	High pressure water	1 / year
Precipitator washes	Water spray / wash	1 / 2 – 5 years
Pug mill washes	High pressure water wash	As needed to remove pluggage
Pumps / Associated piping	Rinse w/ water	As needed
Seal oil coolers	rotating brush or scrapers	As needed (approx. 1 / year)
Sludge lancing		
SO3 mitigation dry sorbent inj system washes		
Soot blowing washes		As needed for differential
Tank washes (water storage tanks)	high press. water spray	1 / year
Transformer cooling coils	power wash or water wash	1 / 3 years
Traveling screens	high pressure/rinse	
Turbine Washes	Water and surfactant	
Well water piping washes	High pressure water spray	

d. EPA is outside its authority in making an eligibility determination based on proposed criteria before the proposed rule becomes effective.

EPA is proposing to provide an exemption from new copper and iron limitations for existing discharges of nonchemical metal cleaning wastes that have historically been managed as low volume wastes, since the costs for dischargers to comply with the limits is not known (78 FR at 34465). EPA is soliciting comments on the specific generating units that should be included in the proposed exemption. In order to qualify for the proposed exemption, the following three criteria must be met:

- The generating unit must currently generate nonchemical metal cleaning wastes;
- The generating unit must discharge the nonchemical metal cleaning waste; and
- The generating unit must be located at a plant that is authorized to discharge the nonchemical metal cleaning waste without limitations for copper and iron (78 FR at 34471).

EPA has specifically requested comments on the proposed exemption that will allow plants to set BAT limits equal to current BPT limits for low volume waste. EPA has requested comments from those generating units that might qualify for the exemption so that EPA can develop a list of generating plants eligible for the exemption. By making eligibility determinations based on proposed criteria for meeting the terms of a proposed rule, EPA is acting outside its statutory authority.

In essence. EPA is giving the proposed rule retroactive effect by imposing new standards and criteria on the generating units that may or may not qualify for the exemption prior to the rule's finalization. "It is well settled that an agency may not promulgate a retroactive rule absent express congressional authorization."[33] EPA must engage in notice and comment process before formulating and acting on regulations. [34]

AEP agrees that EPA is allowed to request information from those entities of interest regarding the exemption eligibility and may also invite comment on the proposed rule. However, in this case, EPA has stated that it may decide to implement the criteria and exemption in developing a "proposed list of generating units eligible for the exemption" as part of the final rule; meaning, the criteria and exemptions would be given the power of law prior to the rule's effective date (78 FR at 34471).

If EPA makes eligibility determinations prior to the effective date of the proposed rule. then once the rule becomes effective, those generating units failing to participate or provide documentation that they have met the proposed criteria will suddenly be operating outside of the law and have new liabilities imposed on them because they failed to comply with a proposed rule

[33] Northeast Hosp. Corp. v. Sebelius, 657 F.3d 1, 13-14 (D.C. Cir. 2011) (*citing* Bowen v. Georgetown Univ. Hosp., 488 U.S. 204, 208 (1988).

[34] Administrative Procedure Act §§ 553, 556, 557.

simply because they did not participate in the discretionary process of filing public comments. Failure to comply with a proposed rule will not carry with it legal consequences, unless the final rule is given retroactive effect.

AEP also agrees that EPA has the authority to propose criteria for the exemption within the proposed rule. However, enforcing the proposed criteria and granting or denying proposed exemptions based on the proposed criteria would be substantively inconsistent with prior EPA practice regarding low volume waste discharges.[35]

As EPA is aware, the Administrative Procedure Act requires agencies to follow a certain rulemaking process.[36] That process does not permit EPA to enforce rules prior to their enactment or give rules retroactive effect upon their enactment.

e. The following AEP facilities are eligible for the exemption from the proposed nonchemical metal cleaning waste technology limits.

Despite the questionable legality of the agency's request for a list of specific generating units eligible for the proposed exemption from new copper and iron limitations for existing discharges of nonchemical metal cleaning wastes that have historically been managed as low volume wastes, AEP is providing the requested list. In order to qualify for the proposed exemption, the following three criteria must be met:

- The generating unit must currently generate nonchemical metal cleaning wastes;
- The generating unit must discharge the nonchemical metal cleaning waste; and
- The generating unit must be located at a plant that is authorized to discharge the nonchemical metal cleaning waste without limitations for copper and iron (78 FR at 34471).

[35] Nat'l Mining Assoc. v. Dep't of Labor, 292 F.3d 849, 860 (D.C. Cir. 2002). Courts will "first look to see whether it [the rule] effects a substantive change from the agency's prior regulation or practice.

[36] APA §§ 552, 553

The listed facilities meet the above criteria and are identified as follows:

John E. Amos	Arsenal Hill	Big Sandy
Cardinal	Clifty Creek	Clinch River
Comanche	D.C. Cook	Conesville
Dresden	Flint Creek	General James M. Gavin
Glen Lyn	Kammer	Kanawha River
Knox Lee	Kyger Creek	Lawrenceburg
Lieberman	Lone Star	Mitchell
Mountaineer	Muskingum River	Northeastern
Picway	Pirkey	Riverside
Rockport	Philip Sporn	J. Lamar Stall
Tanners Creek	Tulsa	Turk
Southwestern	Waterford	Welsh
Wilkes		

f. The cost of complying with iron and copper limits for nonchemical metal cleaning wastes would be prohibitively and unnecessarily high.

Since EPA has admitted that it does not know what it would cost the industry to comply with new iron and copper limits for nonchemical metal cleaning wastes, it has asked for information on the actions that would be needed to comply with the limits and the associated capital and O&M costs (78 FR at 34472). To respond to this request for information, AEP assumed a plausible case scenario that would require the treatment of nonchemical metal cleaning wastes (NCMCW) at a plant that currently has no existing equipment or facilities for handling or treating this waste. It was assumed that all necessary equipment would need to be purchased and installed. All costs listed are installed costs (2013$). Costs were estimated for equipment based on representative units in three size classes; 1300 MW; 600 – 800 MW; and subcritical units. Costs for Heat Recovery Steam Generator (HRSG) plants are assumed to be equal to the cost for subcritical units.

It is assumed the cost for an individual plant will be the cost of treatment for the largest sized unit at the plant. Though NCMCW processes can be performed on multiple units at one time, the largest volume metal cleaning processes require unit outages and can have moderate to extensive manpower and equipment requirements. As such, it is assumed that multiple cleanings of the largest volume metal cleaning processes will not be performed at the same time. Thus, it was decided that NCMCW treatment facilities should be sized, with an appropriate safety factor. for the largest cleaning process performed on the largest sized unit at a plant. A safety factor is included in the event estimates of the largest volume waste processes are low and to allow additional treatment capacity of waste from smaller volume cleaning processes that could be performed at the same time as the larger volume metal cleanings. Detailed assumptions of a system to capture/contain, transport and treat NCMCW include:

Storage Tank

It is assumed not all NCMCW will be treated instantaneously during the actual cleaning process as some process flows will be too great while others will be too small for a treatment facility to handle immediately. As such a storage tank will be necessary to hold the waste until it is treated. The tank will be sized based on the estimated volume of waste generated during air heater washes multiplied by a safety factor of 2.0. Air heater wash volumes are used as a size basis for the tank as this is the non-chemical metal cleaning waste process with the highest volume that can be quantified at this time.

For a 1300 MW unit, air heater washes are estimated to generate 150 gpm of waste for approximately 24 hours. This generates a total of 650,000 gallons of waste and applying the multiplication factor results in a tank size of 1,300,000 gallons. An estimated installed tank cost is $1 per gallon. This results in an estimated tank cost of $1,300,000.

For 600 – 800 MW units, air heater washes are estimated to generate waste volumes ranging from approximately 225,000 – 325,000 gallons of waste. Assuming the larger volume, the required storage tank volume is obtained by applying the multiplication factor of 2.0 to the estimated waste volume, resulting in a storage tank volume 650,000 gallons. This gives an estimated tank cost of $650,000.

For subcritical units, air heater washes are estimated to generate waste volumes ranging from approximately 100,000 – 175,000 gallons. Again assuming the larger volume, the required storage tank volume is obtained by applying the multiplication factor of 2.0 to the estimated waste volume, resulting in a storage tank volume of 350,000 gallons. This gives an estimated tank cost of $350,000.

Piping

It is assumed piping will need to be installed for transporting NCMCW. In more detail, it is assumed temporary piping will be used to pipe the waste from the cleaning process location to a central 'collection' location (such as an isolated sump). From this one 'collection' location, it is assumed that permanent piping will be installed to transport the waste to the storage tank and treatment facility and then to an outfall or pond location.

The location of the storage tank is assumed to be similar to that of existing metal cleaning waste tanks at AEP plants as there is generally additional space in these areas and that is relatively close to the pond or outfall locations. As such, the distance of piping required was calculated using plot plans of AEP plants that have existing metal cleaning waste tanks. The permanent piping distance was estimated to be the average general distance from the center of a plant's units to the existing tanks. The temporary piping distance required was assumed to be one-half of the permanent pipe required distance.

For AEP plants with existing metal cleaning waste tanks, the distance from the plant units to the tanks, was calculated to be an average of approximately 2000 ft. As such, the permanent piping distance required is assumed to be 2000 ft while the temporary piping distance was assumed to be 1000 ft. These piping distances were assumed to apply to all plants, regardless of plant size. An estimated installed cost for piping is $200 per ft. This gives an estimated piping cost of $600,000 for all plants.

Pumps

It is assumed pumps will need to be installed to transport the NCMCW. The waste will need to be moved from the location of the cleaning process to the 'collection' location and then to the holding tank and treatment facility. After treatment, the NCMCW will need to be pumped from the treatment facility to the final outfall location, likely a treatment pond. As such it was assumed that two separate sets of pumps would be needed (from the cleaning location to the treatment facility; and from the treatment facility to the outfall location).

Both sets of pumps were sized for the highest identified flow rate used during a NCMCW process. Typically air heater washes and boiler fireside cleaning processes were identified as the cleaning processes requiring the highest flow rate. These flow rates were estimated to range from 150 – 300 gpm. A flow rate of 300 gpm and a distance of 3000 ft (previously identified length of piping required) were used to estimate pump sizes and costs. It was assumed that a total of 4 pumps are required to provide system redundancy and the ability to handle larger than expected flows. The cost for pumps is assumed to apply to all plants regardless of size as required flow rates rarely differ from plant to plant and all piping distances were assumed to apply equally to all plants. An estimated installed pump cost is $20,000 per pump. Based on these requirements, total installed pumps costs are estimated to be $80,000 per plant.

Treatment Facility

The treatment necessary to achieve the proposed limits for NCMCW is assumed to be a combination of solid contact clarification and filtration. Several stages of filtration may be required, however the extent of filtration is unknown without further waste characterization. The treatment facility will also need to include dewatering equipment (thickener, filter press) to collect solids for landfill disposal. The treatment facility will be sized to process the entire volume of the holding tank within an acceptable time frame such that the tank can be used to hold further NCMCW. An acceptable time frame to treat the volume of the tank is assumed to be 7 days with the treatment facility operating an average of 16 hours per day, or 5 days operating for 24 hours per day.

The cost for the treatment facility is based on the overall costs for recently installed FGD wastewater treatment plants at three AEP affiliated facilities. The FGD wastewater treatment plants consist of clarification, filtration and dewatering equipment. It was assumed this FGD wastewater treatment equipment and associated costs are similar to those that will be required for a NCMCW treatment facility. Using costs for the three FGD wastewater treatment plants, a curve was created showing the relationship between treatment plant flow rate and cost. A cost for a NCMCW treatment facility was then derived from this curve based on the size of the treatment facility derived from the above criteria.

Summary

For 1300 MW units, which require an estimated storage tank volume of 1,300,000 gallons and operating a NCMCW treatment facility for 7 days/16 hours per day or 5 days/24 hours per day equates to a treatment facility flow rate of 200 gpm. Based on FGD wastewater treatment plant costs, a 200 gpm NCMCW treatment facility is estimated to cost $29,000,000.

For 600 – 800 MW units, which require an estimated storage tank volume of 650,000 gallons and repeating the treatment facility operational assumptions above, results in a required treatment facility flow rate of approximately 100 gpm. Based on FGD wastewater treatment plant costs, a 100 gpm NCMCW treatment facility is estimated to cost $25,500,000.

For subcritical units, which require an estimated storage tank volume of 350,000 gallons and again repeating the treatment facility operational assumptions, results in a required treatment facility flow rate of approximately 55 gpm. Based on FGD wastewater treatment plant costs, a 55 gpm NCMCW treatment facility is estimated to cost $22,500,000.

Table 9. NCMCW Treatment System Assumption and Costs Summary is a summary of assumptions and total costs for each unit series.

	UNIT SERIES		
	1300 MW	**600 – 800 MW**	**Subcritical / HRSG**
Piping	3000 ft total	3000 ft total	3000 ft total
	$200 / ft	$200 / ft	$200 / ft
	$600,000	**$600,000**	**$600,000**
Pumps	300 gpm, 3000 ft	300 gpm, 3000 ft	300 gpm, 3000 ft
	$20,000 / pump	$20,000 / pump	$20,000 / pump
	4 pump total	4 pump total	4 pump total
	$80,000	**$80,000**	**$80,000**
Storage Tank	1,300,000 gals	650,000 gals	350,000 gals
	$1 / gal	$1 / gal	$1 / gal
	$1,300,000	**$650,000**	**$350,000**
Treatment Facility	200 gpm flow rate	100 gpm flow rate	55 gpm flow rate
	$29,000,000	**$25,500,000**	**$22,500,000**
Total Cost	$30,980,000	**$26,830,000**	**$23,530,000**

Adding together all of the costs associated with collecting, holding, transporting and treating a typical the nonchemical metal cleaning waste generated by an air heater wash for a 1300MW unit, it would cost AEP $31 million in direct capital costs (2013$). For units sized between 600 to 800 MW, the total cost for installation of treatment equipment and the subsequent treatment would be $26.8 million (2013$), and for subcriticial or HRSG units, the costs would be $23.5 million (2013$). Based on these costs and extrapolating to other affected facilities on a MW basis, it would cost AEP approximately $766 million (2013$) in capital costs to meet EPA's proposed iron and copper limits for nonchemical metal cleaning wastes or $701 million in 2010$. This is a tremendous cost to incur for the treatment of a waste stream that is currently managed without incident.

g. Should iron and copper limits be imposed on nonchemical metal cleaning wastes, EPA should allow a compliance schedule.

EPA is proposing a compliance schedule of "as soon as possible" in the first NPDES permit renewal after July 1, 2017, for all of the affected waste streams; however, no such compliance period is proposed for nonchemical metal cleaning wastes. This appears to be based on EPA's erroneous assumption that the proposed rule will not require existing facilities to change management of nonchemical metal cleaning wastes. As has been described above, it may be necessary to perform extensive alterations of plant facilities, including tank and pipe installations and the construction of sumps and treatment facilities, to meet the new requirements. At the same time, other retrofits will be underway to meet the other new ELG requirements, possibly including retrofits for dry bottom ash disposal, new landfills, new FGD treatment systems and new plant water balance configurations.

EPA should revise the rule proposal to include a reasonable compliance schedule, possibly longer than three years, to allow for the installation of nonchemical metal cleaning waste treatment facilities.

D. AEP supports the agency's proposed legacy wastewater provisions.

Under its proposed regulatory implementation scheme, EPA is proposing that certain BAT requirements for existing sources apply to discharges of FGD wastewater, fly ash and bottom ash transport water, FGMC wastewater, combustion residual leachate, and gasification wastewater generated on or after the date established by the permitting authority that is as soon as possible within the first permit cycle after July 1, 2017 (78 FR at 34523). The agency is also proposing for direct dischargers that, "such wastewater generated prior to that date (i.e. "legacy" wastewater) would remain subject to the existing BPT effluent limits." This is based on the fact that some wastewater treatment technologies do not represent BAT for legacy wastewater. For example, this was the case for legacy FGD wastewater (78 FR at 34461), fly ash transport water (Id.), bottom ash transport water (78 FR at 34462) and combustion residual leachate (78 FR at 34463). As a result, EPA has proposed that discharges of legacy FGD wastewater, fly ash transport water, bottom ash transport water and combustion residual leachate would remain subject to the existing BPT effluent limitations for those specific wastewaters. AEP agrees with this proposal and encourages EPA to implement it in the final revised ELGs. The proposed revisions will allow utilities to discharge legacy wastewaters in compliance with existing water quality standards and effluent guidelines, while at the same time, allowing them to close out impoundments as necessary. Without the legacy wastewater provisions, utilities would be forced to develop technologies that could separately treat the current and legacy wastewaters. For example, if ongoing and legacy fly ash transport waters had to meet BAT limitations, there would be no practicable way to get rid of the legacy transport waters, since there would be "no discharge" requirement under the BAT limitations. Some of the water could be recycled, particularly in bottom ash systems, but for the most part, there would be no effective way to dispose of the legacy wastewaters other than by the energy intensive process of forced evaporation.

E. EPA's proposed anti-circumvention provisions would discourage water reuse and should be revised to allow water reuse, provided all applicable water quality standards are met.

EPA has proposed anti-circumvention provisions that would 1) require that compliance with new effluent limits applicable to a particular waste stream be demonstrated prior to use in another plant process that results in a discharge or mixing with other waste steams; 2) would prevent the circumvention of an effluent subject to a zero discharge limit to a process with discharge limits that are less stringent than intended by the ELGs; and 3) require the use of EPA approved analytical methods that are sufficiently sensitive to provide reliable quantified results at levels necessary to demonstrate compliance with applicable effluent limits (78 FR at 34465-34466). These anti-circumvention provisions, particularly the first and second provisions, would limit opportunities for water reuse. For example, bottom ash transport water is used at some power plants for scrubber make-up water, fly ash conditioning or other plant services. However, the second proposed anti-circumvention provision, along with the proposed zero discharge limit for bottom ash transport water pollutants, would prevent the use of this water in <u>any</u> power plant process.

It is also unclear why the agency would allow the discharge of treated FGD wastewater, a waste stream with a relatively heavy pollutant loading, but not allow the reuse and ultimate discharge of bottom ash transport water, which has a much lower pollutant loading. Perhaps the agency is more focused on the elimination of coal ash impoundments than it is on the reduction of pollutant loadings to the environment. We remind the agency that its authority under the Clean Water Act effluent guidelines/NPDES program, as discussed in the next section, is limited to controlling discharges and not specific waste handling practices.

In the past, the agency has encouraged the commingling and centralized treatment of wastewater. In the 1980 Steam Electric Development Document, the agency states that the, "consolidation of waste streams to a centralized treatment system is permitted and encouraged."[37] The 1974 preamble to the steam electric guidelines makes a similar statement. "It is also recognized by EPA that, due to the economies of scale, combining similar waste streams for treatment to remove the same pollutants is generally less costly than separate treatment of these waste streams. The employment of cost-saving alternatives in meeting the effluent limitations should not be discouraged" (39 FR at 36196). Finally, the agency notes that, "In the event that *waste streams from various sources are combined for treatment or discharge (italics added)*, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (g) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source."[38] EPA is obviously not prohibiting the combination of wastewaters, but it is prohibiting the use of dilution to meet discharge limits.

With regards to the agency's third proposed anti-circumvention provision (i.e. use of sufficiently sensitive methods), AEP encourages EPA to only accept analytical results that have been obtained through the use of methods following those listed in 40 CFR Part 136.

F. It does not appear that EPA possesses the authority under the Clean Water Act upon which it is relying to propose Best Management Practices for CCR surface impoundments.

The proposed rule sets forth BMPs to address the structural integrity of active and inactive surface impoundments (78 FR at 34466). BMP conditions may be included in a permit

[37] EPA. Development Document for Proposed Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category. (Sept. 1980), at 470.

[38] 40 C.F.R. § 423.13(h); *See also* 40 C.F.R. § 423.12(b)(12) (BPT)

pursuant to the CWA and courts have upheld the inclusion of such conditions.[39] However, the proposed BMPs go beyond practices, inspection, record keeping, data collection or the kinds of BMPs framed by the CWA. Much of the text of the proposed BMPs` is technical in nature and in certain instances may require a permittee to take specific actions that are outside the scope of a typical BMP.

For example, the first proposed BMP would require monitoring, inspection and record keeping and the identification of certain conditions. Should these conditions develop, the proposed BMP requires that certain emergency steps be taken. The proposed emergency actions extend beyond the scope of what is typically considered a BMP and beyond the scope of the CWA NPDES program authorization. The CWA NPDES prohibits unauthorized discharges without a permit, no more.[40]

Similarly, the second proposed BMP would require the permittee to submit plans for design, construction, maintenance and closure of the surface impoundments [notwithstanding that at the outset of the section, EPA stated that BMPs would not include closure requirements (78 FR at 34466)] as well as an annual inspections by an independent professional engineer (78 FR at 34466-34467). BMPs that address the technical requirements of a structure over which EPA was not granted authority under the CWA are also outside the scope of EPA to propose in the current rulemaking. Further, EPA has previously rejected the need in another Clean Water Act program to specify that professional engineers performing duties under the rules must be "independent". Specifically, EPA recognized in rulemakings in the oil spill prevention, control and countermeasure (SPCC) program that professional engineers "will uphold the integrity of

[39] 33. U.S.C. §§ 1314(e) and 1342 (a)(2). *See* Citizen Coal Council et al v. U.S. EPA, 447 F.3d 879 (6th Cir. 2006)
[40] 33 U.S.C. § 1311

their profession and only certify Plans that meet regulatory requirements" and therefore maintain sufficient independence (67 FR at 47053).

Moreover, some of the very BMPs that EPA has proposed will address the same or similar requirements to which the proposed CCR rule is aimed and which are addressed by the various state regulatory agencies authorized with the command of waste material and prevention of catastrophic releases. As EPA is aware and has stated as much, two scenarios for regulation of CCR material have been proposed and are pending finalization. The first scenario regulates CCR material as a special waste under Subtitle C of RCRA, the second as a non-hazardous waste under Subtitle D (75 FR at 35240 – 35263). Under either proposed scenario EPA has set out in detail in another rulemaking, the technical requirements including location, design, and operating criteria and closure requirements that will apply to CCR surface impoundments. [41]

Proposing and publishing regulations that so closely and similarly target the identical activity and risk is clearly an act of redundancy by EPA. So, if EPA were to issue these proposed BMPs, not only will they will be acting outside the scope of the CWA but EPA will be acting in violation of 33 U.S.C. § 1251 which specifically prohibits actions of redundancy. [42] EPA can best use its time and efforts by addressing the coordination of the ELG deadlines and implementation of the CCR rule and abandon the currently proposed BMPs that address the identical risks and structures that are currently regulated by the States and proposed for regulation by EPA under RCRA. Finally, we would like to point out that EPA's Office of

[41] EPA claimed its regulatory authority for CCR waste disposal structures such as surface impoundments under either RCRA § 3004 (x) or § 4004. *See* 75 FR 35135-35136.

[42] 33 U.S.C. § 1251 states "It is the national policy that to the maximum extent possible the procedures utilized for implementing this chapter shall encourage the drastic minimization of paperwork and interagency decision procedures, and the best use of available manpower and funds, so as to prevent needless duplication and unnecessary delays at all levels of government." Executive Order 12174 Federal Paperwork Reduction also addresses EPA's proposed duplicative efforts.

Resource Conservation and Recovery recently sent letters to all owners of coal ash impoundments drawing conclusion to their multi-year program of structural integrity assessments of over 500 impoundments. The results of those assessments resulted in no impoundments receiving an unsatisfactory rating. The letter stated that,

> "agencies within your State have an important role in the ongoing monitoring and oversight of these units. We are therefore providing all of the information that you have sent to EPA to the appropriate State agency for their use in their routine monitoring and oversight of these units and expect that they will be the primary point of contact with respect to the continued oversight of these units. (Emphasis added.)"

We agree with the position of that EPA Office that the State dam safety control agencies are the appropriate entities to deal with this issue.

G. While AEP supports the voluntary incentives, it is not clear when the additional two and five year compliance periods would start.

EPA is considering the establishment of a voluntary incentive program that would provide more time for proposed BAT requirements to be implemented (78 FR at 34458). Two additional years would be granted to implement required treatment technologies if all CCR surface impoundments at a facility (excluding leachate impoundments), would be dewatered, closed and capped. Five additional years would be granted to implement required treatment technologies if all process wastewater discharges to surface waters, with the exception of cooling water discharges, were eliminated. While AEP supports the proposed incentives, it is not clear when the additional two and five year compliance periods would begin. AEP is in agreement with UWAG and suggests that, "the two and five additional years should, in keeping with the compliance dates proposed for the specific limitations, begin to run on the compliance date that the permitting authority determines is "as soon as possible" in the first permit renewal cycle after

July1, 2017. Where there is more than one compliance date, the lastest of the dates should begin the two and five additional years for the voluntary measures."[43]

H. Clarification is needed regarding the proposed compliance schedules.

EPA is proposing that certain BAT limitations "would apply on a date determined by the permitting authority that is as soon as possible when the next permit is issued beginning July 1, 2017." (78 FR at 34479) which is approximately three years from the anticipated effective date of this rule. EPA correctly points out that utilities "will need time to raise the capital, plan and design the system, procure equipment, construct and then test the system." As a result, it is allowing up to eight years from the date of promulgation of any final ELGs for a power plant to attain compliance with the proposed ELG limitations. However, not all facilities will be able to take advantage of this 8-year compliance period. For example, if a facility's NPDES permit renewal date falls on July 30, 2017, will that facility be required to be in compliance with all new effluent guidelines on that date or must that particular permit contain the new effluent guideline requirements with a prospective compliance date? If the latter, would a compliance period, in fact, be allowed? EPA states that it,

> "recognizes that permitting authorities have discretion with respect to when to reissue permits and can take into consideration the need to provide additional time to include BAT limits to prevent or minimize forced outages. Thus, in some cases, the new BAT requirements may as a practical matter be applied to a facility sometime after July 1, 2017." (78 FR at 34480).

EPA also states that, "the permitting authority could establish any additional interim milestones, as appropriate, within these timelines." (Id.). But it remains unclear whether the proposed timelines apply to permit implementation or to actual compliance. The agency does

[43] UWAG ELG Comments, September 20, 2013.

state that it expects that the proposed BAT limitations will be applied to all permits no later than July 1, 2022, but again, it does not specify the actual compliance date for the limits.

In Chapter 3 of the agency's Regulatory Impact Analysis, it states that, "EPA assumes that plants would implement control technologies three years after their NPDES permit comes up for renewal after the rule promulgation."[44] *It is understood that compliance is likely to be* staggered over the five year time period from July 1, 2017 to July 1, 2022, but it is not clear if compliance periods would be allowed beyond July 1, 2022. Granted, that a facility could start compliance activities before the ELGs are implemented in its NPDES permit, but what company would make such a commitment without the regulatory requirement to do so actually in force in its facility's permit? In fact, in the regulated electric utility industry, it is not possible to obtain cost recovery for such work unless it is specifically required by law or regulation.

Even setting aside all of the above concerns, it is not possible for a utility to comply with the proposed technology requirements within the three to eight year compliance period. For example, in the event that a final ELG rule requires mandatory conversions of wet fly ash systems to dry ash disposal systems, more than five years will be necessary for the design, construction and permitting of the alternative landfill disposal space that will be necessary to manage the CCR material that would be diverted from the impoundments to the new landfills. According to the EOP report[45] prepared for USWAG in the CCR rulemaking docket, a five-year implementation time period for a wet to dry conversion is not practical given the uncertainties over the availability of adequate engineering capacity to conduct all of the conversions for the entire industry within this time period. The amount of equipment and labor needed to support so

[44] EPA Regulatory Impact Analysis, April 2013.

[45] EOP Group, "Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal-fired Electric Utilities," Nov. 11, 2010.

many projects within the same time period would be overwhelming. EOP estimates that the industry will need up to ten years to site, design, permit, construct and make operational alternative disposal capacity for displaced CCR in addition to the needed construction of new wastewater treatment capacity.

I. Economic Impact and Social Cost Analysis

1. In some cases, annualization and cost recovery periods shorter than 15 years need to be accounted for in the proposed rule.

As has been mentioned earlier, the time period assumed for cost recovery is a primary consideration when the cost effectiveness of any new technology installation is evaluated. EPA assumes that costs are annualized over a 20-year period, but has previously used a 15-year period to develop ELGs for other industry categories. But in some cases, even a 15-year service life assumption is not appropriate. This is the case with Public Service Company of Oklahoma's (PSO's) Northeastern Plant where a coal-fired unit is planned to be retired by 2026, providing a significantly shorter time period for cost annualization. Based on EPA's preferred option and an expected ELG compliance date of 12/12/2021 for this unit (first permit renewal after July 1, 2017), the bottom ash transport system would need to be converted to a "dry" system and be operational by the compliance date. After the completion of the retrofit, the plant will only operate for an additional 5 years before being retired. Using the cost effectiveness information estimated for two AEP dry bottom ash conversions as examples (Table 10), the effects of the shortened cost recovery period can be illustrated.

The direct costs in 2010 dollars to retrofit dry bottom ash systems at these two facilities were provided earlier (Table 5). These costs were converted to 1981 dollars and annualized over a 20-year period at 7% in order to calculate $/TWPE values for both plants (Table 6). Use of a shorter cost recovery period has a significant effect on the cost effectiveness of dry bottom ash conversions. Using a 15-year annualization period for Plant 1 increases the $/TWPE by over 16%, from $16,007 to $18,639 per TWPE removed (Table 10). Using a 5-year cost recovery period, the $/TWPE values increases by almost 160%, further devaluing an already not-cost-effective technology retrofit (Table 10).

This analysis illustrates that not only is the dry bottom ash conversion not cost effective for any plant at any cost recovery period, but that some provision needs to be included in the proposed ELG rule that accounts for plants that will be retired prior to a 20-year cost annualization period. If the new ELGs are adopted as proposed, the PSO Northeastern Plant must install a dry bottom ash conversion by December 12, 2021, but due to an agreement among

Table 10.

Plant	20-yr Annualization Direct Capital Costs (millions 1981$)	15-yr Annualization Direct Capital Costs (millions 1981$)	5-yr Annualization Direct Capital Costs (millions1981$)
Plant 1	0.73	0.85	1.89
Plant 2	1.26	1.47	3.26

Plant	$/TWPE (1981$) 20-yr annualization	$/TWPE (1981$) 15-yr annualization	$/TWPE (1981$) 5-yr annualization
Plant 1	16,007	18,639	41,444
Plant 2	4,961	5,787	12,835

stakeholders regarding its air pollution control requirements, the plant must be retired by 2026, providing only five years to recover the cost of the dry bottom ash conversion from the customers that receive service during the period of ELG compliance.

Some minimal cost-recovery period must be used to estimate the cost effectiveness of the proposed technology revisions and in cases where that cost annualization period is not available, the cost effectiveness needs to be reassessed. Under option 4a, EPA has proposed that the "dry" bottom ash handling requirement be applied to units that are greater than 400 MW (nameplate capacity) (78 FR at 34470). The agency recognizes that the costs associated with such a retrofit are substantial and carefully considered the affordability of this option on a unit MW basis. It concluded that companies may retire units that are 400 MW or smaller instead of making the investments necessary to comply with the proposed "dry" bottom ash management requirement.

If the agency is willing to acknowledge that a unit MW threshold is appropriate to account for the affordability of dry bottom ash retrofits, why not consider a similar threshold based on cost recovery periods? Not every facility will be able to take advantage of a 20-year cost recovery period to recoup the costs of technology retrofits. While the case of the PSO Northeastern Plant may be unique, it clearly illustrates that a cost recovery threshold is needed to address these situations. This is particularly true since this EPA option does not allow state discretion in determining the need for and the affordability of, the required retrofit. EPA must allow facilities such as the Northeastern Plant to be exempted from the dry bottom ash requirement. These exemptions can be based on cost recovery periods or on regulatory discretion, but in any case, a provision must be included in the rule to account for these situations.

2. Compliance Costs

The EPA's estimates of technology costs were determined from information received via survey responses, site visits, sampling episodes, individual power plants, and equipment vendors. The Agency used this information as inputs to the models employed to determine whether a specific facility would require a technology retrofit to comply with the criteria in the proposed ELG rule. The modeling alone introduces two potential degrees of error in the analysis. The accuracy of the model output is directly dependent upon: 1) how well the model replicates the system or process being modeled; and 2) the accuracy of the data inputs. In Section IX.B.5. the EPA acknowledges its uncertainty with the validity of the data inputs by soliciting additional data or information on pollutant loadings that would corroborate or correct the data used in its analysis, including data or information relating to the pollutants of concern identified in the ELG proposed rulemaking. The EPA also questions how the data should be analyzed based on: age; treatment of non-detects; treatment of pollutants in source water; and calculation of toxic-weighted pollutant equivalents. These specific requests for review and comment on the most fundamental input to the analysis for evaluating whether a compliance technology is needed at a facility calls into question all of EPA's conclusions outlined in the proposed rule.

EPA superficially assumes that only incremental costs will be incurred by power plant owners requiring a technology retrofit for compliance, without any site-specific examination to assess if any existing treatment technology is optimally operating and/or has the capacity to accommodate the additional pollutant loadings required for compliance with this proposed ELG rule. This will potentially lead to the further underestimation of the costs of these guidelines. EPA asserts that the costs developed in their assessment are site-specific, but this position is based on data provided in surveys for which the Agency is also asking owners to verify post-use in its determination of compliance costs. Even if one considers that the survey information provided is valid, the approach employed by EPA to determine an initial cost estimate for an individual facility falls far short of one that would pass muster for an owner to go forward with a retrofit project. Making these general assumptions and escalating costs to reflect the ELG impact to the entire electric utility industry is misleading and doing so introduces amplified error and exacerbates the underestimate of cost to comply with the ELG rule. AEP's costs for compliance with the rule, however, provide a more appropriate basis for economic evaluation, in that it includes specific plant data (presented herein) in addition to cost estimates derived from completed installations. Thus, AEP's costs for compliance with the proposed rule give a more realistic site-specific estimate at each of AEP's power plant facilities that would be affected by the rule for compliance with Option 4.

The EPA's cost estimates of compliance with each of the options outlined in the proposed ELG rulemaking are further inherently flawed as they are expressed as a single value, when it would be more reasonable – and believable – to express as a cost with a range of variability indicative of the level of certainty in the estimate – i.e. plus or minus a percentage of the estimate (e.g. +/- 50%). Expressing costs in this manner would also be consistent with the principles and process standards outlined by the Project Management Institute[46] in the Project Management Body of Knowledge (PMBOK), which is an industry standard used for executing technology retrofit projects of the magnitude expected for compliance with the ELG rulemaking. The PMBOK is a collection of processes and knowledge areas generally accepted as best practices within the project management discipline. It is an internationally-recognized project management standard, providing the fundamentals of project management for all types of projects, including construction projects.

Using PMBOK, projects are executed using a phased management process through which each project will progress from initiation to closeout and include the following activities: project initiation, project planning, preliminary engineering and design, procurement needs, detailed engineering and design, work planning, scheduling, procurement, construction contracts awarded, project implementation, project closeout. The accuracy of a project's estimate logically improves as the execution proceeds through the phases as follows, with the band range shown representing the accuracy at the beginning of the phase: Phase 1 – 50%, Phase 2 – 25%, and Phase 3 – 10%.

[46] PMBOK® Guide and Standards, from http://www.pmi.org.

EPA fails to provide any such accuracy ranges, giving the false notion that the costs of the rule for each option as presented are all inclusive. As can be deciphered in the PMBOK phased process, many variables exist that will ultimately affect the scope and cost of any project and decision to retrofit. Instead of acknowledging the inherent uncertainty in estimating and including appropriate ranges of accuracy in compilation of its costs, EPA relies on survey data to extrapolate an estimate from a technology vendor based on a single project, which introduces an unknown level of uncertainty in each and every estimate included in the summation of the total for compliance with each of EPA's options.

To illustrate this point that the estimated costs in the proposed rulemaking for industry compliance are highly questionable, consider that AEP's estimated compliance with Option 4 for its operating subsidiaries alone will result in the company incurring costs estimated at approximately $3.1 billion (2010$) ($3.9 billion fully-loaded 2010$) on a pre-tax direct-cost basis. As noted in the TDD, EPA estimates that under Option 4, the capital compliance cost for the entire industry exceeds $8 billion dollars. As AEP's estimated costs are nearly 40% (50% if fully-loaded costs are considered) of EPA's estimated compliance cost for the industry, EPA's estimate has to be highly questioned, considering AEP only owns approximately 4% of the 1,079 plants EPA considered in this rulemaking.

AEP is also concerned that in its examination of the proposed rule and its technical documents, that there is a lack of transparency in the costs estimated in EPA's analysis from the perspective of quantification and delineation of costs by specific direct cost categories. EPA maintains that:

> "EPA's cost estimates include the following key cost components: capital costs (one-time costs); annual operating and maintenance costs (which are incurred every year); and other one-time or recurring costs. Capital costs comprise the direct and indirect costs associated with the

purchase, delivery, and installation of pollution control technologies. Capital cost elements are specific to the industry and *commonly* include purchased equipment and freight, equipment installation, buildings, site preparation, engineering costs, construction expenses, contractor's fees, and contingency." (Emphasis added) [47]

EPA does not definitively state that these items are included in their cost estimates, but merely states that these are the common items that comprise capital cost estimates. For example, contingencies included in the direct cost estimation in the EPA analysis are a concern. Contingency is an allowance for costs that a company knows it will need but for which it lacks enough detailed planning or engineering information to identify or quantify. It addresses "known unknowns" which are a legitimate cost in any project activity. Even if one accepts that EPA included contingency and/or general contractor profits and overhead in its analysis the legitimacy of their inclusion is questionable because the items appear not to be quantified and delineated in vendor quotes or in EPA's technical documents, as has been the Agency's past practice.

Further, the amount of contingency is a reflection of the cost estimate and its accuracy. Since, EPA gives no accuracy ranges as explained above, AEP cannot fully comment about the amount of contingency embedded in the agency's cost estimates. For example, if the amount of contingency included in the EPA cost estimation is small, then the EPA supposes a high degree of accuracy in its cost estimation for compliance costs associated with the rule. This is a position that AEP strongly disagrees with given the disparity of its cost estimates compared to the agency's coupled with the agency's lack of transparency.

Additionally, EPA assessments of compliance costs do not account for several other integral cost considerations, such as the costs associated with and necessary for obtaining

[47] EPA Technical Development Document, April 2013, at 9-2.

jurisdictional regulatory approval, where applicable. EPA also fails in its analysis to account for any equipment or material that would have to be retired or rendered obsolete in response to this rule. Any remaining depreciable balance of these assets would have to be accounted for along with consideration for removal, where necessary.

3. Economic Impact and Social Cost Analysis

EPA's annualization of the compliance costs is misleading in that: 1) it characterizes costs as affordable; and 2) neglects to consider the impacts to companies for financing in a capital intensive industry. EPA assumes that the cost of these retrofits will be annualized over a 20-year period, but this position inherently assumes that all of the affected facilities from this rule will operate over that entire timeframe. Given the current environmental regulatory climate, older and less efficient facilities that dispatch less frequently, but provide some economic benefit, will be adversely affected through these guidelines and future rule promulgations, such as with proposed CCR and 316(b) rules, as well as the anticipated Greenhouse Gas Standards for existing sources. Though the proposed ELG rule may not make these units uneconomic to generate electricity over a short term by itself, the cumulative effect of the ELG in combination of other regulations may push these units into an accelerated retirement. Many of the affected facilities will not have 20-year lifespans or service lives, but will still have to shoulder the financial burden to comply with these rules in the short term. The EPA's analysis is not sufficiently refined to properly account for these shortened facility service life periods.

For example, such a scenario where a shortened service life is evident when considering the EPA Settlement Agreement that remedies the dispute with the Regional Haze Rule state implementation plan entered in Oklahoma. In the Settlement Agreement AEP and EPA agreed that one of the coal-fired units of the Northeastern Station will retire in 2016, while the other unit will operate through 2026. The remaining operating unit will have to meet compliance with the ELG, as well as CCR, and these costs cannot be annualized over twenty years because the remaining plant life ends in 2026. Any costs that aren't fully amortized will need depreciation adjustment to align with plant retirement dates, elevating the annualized cost impact of the rule. Aligning cost recovery with customers who receive the benefits of service is vitally important for regulatory commissions in order to not unfairly burden future customers with costs for which they do not receive any service benefit.

Further, the EPA assessment of estimated costs for compliance neglects to consider the capital requirements of utility's to install control technologies over a short compliance period of a few years. As stated above, the AEP estimated costs could potentially approach $4 billion. To contrast, AEP's near-term capital forecast is $3+ billion per year, but these expenditures encompass all business segments including transmission and distribution, in addition to generation. Expenditures to comply with the ELG will directly follow the current large expenditures within AEP's capital budget to comply with the Mercury and Air Toxics Standard by the 2015-2016 timeframe.

In its social cost analysis, EPA assumes that the estimated cost to society resulting from compliance with the proposed ELG rulemaking is simply the total compliance costs without accounting for tax effects. That is a valid assumption with respect to who will ultimately be paying for the compliance. However, EPA is confusing the concept of mitigation – i.e. the cost required to reduce pollutant loadings to meet a new standard – with the concept of social cost, which is the expense to an entire society resulting from continuing "business as usual." In this case, the basis for assessing social costs is the impact to society from facilities continuing to operate under the limitations of the current effluent guidelines compared to the projected benefits to society resulting from implementing the new rulemaking. Theoretically, if the social cost exceeds the mitigation cost, society will benefit.

In terms of social costs, if effluent discharges from electric generating units under the current ELG are having an adverse effect on the environment and public health, the challenge is to quantify this impact in economic terms and assign a value to it. The process is fairly subjective as there are likely many different models forecasting the impacts of power generation facilities continuing under the current effluent guidelines – perhaps as long as 100 years. But whatever the length of the period, the difference between operating on a business-as-usual basis versus implementing the proposed ELGs must be valued and discounted to current dollars. This "value" is the externality that represents the impact to society of not implementing the proposed ELG or of industry not complying with the proposed rules post-implementation. It's a process that merits review and scrutiny in terms of how the value is developed, whether or not the value make sense, and how the ranges around that value account for the uncertainty and variability of inputs to the model; expressing it as a single number automatically requires questioning its validity. In summary, developing an estimate of social cost is merely an attempt to put a dollar value on potential public health or environmental impacts going forward from continued use of the current ELG rule limitations. That is very different from calculating the cost to mitigate current discharges to meet the requirements of the proposed ELG rulemaking. The two costs are not comparable although EPA has suggested they are with the only difference being the exclusion of the tax discount afforded to the mitigation costs.

4. Cost-to-Revenue Screening Analysis

The assessment of the economic impacts of the rule per EPA methodology does not provide a reasonable presentation of the full impact on existing individual facilities and their parent entities incurring compliance costs in the cost-to-revenue basis screening-level economic assessment. Given AEP's estimated capital compliance cost for its facilities are roughly 40% of EPA's estimated capital compliance costs for the entire industry, it can be reasonably ascertained that there would be a significant increase in the number of individual steam electric plants flagged by the cost-to-revenue screening analysis and parent entities that would incur costs of greater than 3% of revenues. According to EPA, exceeding this threshold is an indicator of potential financial distress to the facilities and entities; therefore, EPA's analysis paints a rosy picture of little financial impact to utilities when the costs of this rule could cause financial distress and burden utility customers for the foreseeable future.

Further, a substantial number of public utilities and parent entities are vertically integrated businesses, comprised of various business segments including transmission, distribution, and retail services in addition to generation services and electric generating facilities to which this rule targets. Other parent entities operate in other industries where electric generation may or may not be their business focus. Neglecting to consider the vertically integrated construct artificially minimizes the impact of the ELG compliance costs to the specific business segments of parent entities, and unduly penalizes other facets of the business. It also artificially minimizes the impact of this rule on a specific business segment, when the generation portion could be a small, but vital piece of the overall business construct.

Additionally, EPA wrongly claims that the screening analysis makes a "counterfactual, conservative assumption of zero cost pass-through to customers."[48] While this position is less than conservative considering that recovery for environmental investment for utilities in regulatory proceedings is highly probable, it fundamentally neglects the consideration of

[48] Table XI-3, 78 Fed. Reg. at 34494.

downstream effects to customers that will inevitably result in higher electricity prices in a downtrodden economy and demonstrates that EPA further underestimates the real societal impact associated with this rule. Regulated entities are entitled to a fair return on their investment, and such a return will be borne by, and burden, customers in a much higher degree than EPA's analysis describes. Such costs that are not considered in EPA's cost-effective analysis underestimate the expected actual mitigation cost that will be charged to utility customers in any modeling considerations. Absent regulatory treatment, merchant customers will still bear the burden of this rule manifesting in higher electricity prices to cover the exorbitant costs associated with implementing these proposed guidelines.

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

Based on AEP's cost estimate, EPA has significantly underestimated the compliance costs of this rule. If EPA's modeling underestimates the real costs borne by a utility's customers in complying with this rule in its IPM modeling, there will be a greater number of incremental closures with associated reduction in overall generating capacity, likely supplanting lower-cost power with higher-cost power. EPA notes,[49] that its key inputs for the model include the capital, annual fixed O&M, and annual variable O&M costs.

6. Summary of Economic Impacts for Existing Sources

The economic impact of the ELG rulemaking should not be compared on a cost-to-revenue basis as this metric is meaningless and misleading in that it compares the cost for compliance for a single business unit to the total revenue for the entire company. Thus it is not surprising that the results of EPA's economic impacts are negligible versus comparing the cost of compliance to the revenue of the generation business unit of a utility. While more appropriate

[49] EPA Regulatory Impact Analysis, April 2013, at 6-8.

than EPA's approach, even this comparison could be improved as it does not reflect the true impact on a company's owners – i.e. its shareholders. To do so requires calculating the impact on a company's earnings on a $/share basis.

7. **EPA fails to account for all employment impacts in its analysis of job creation.**

EPA has misrepresented reasonably expected employment impacts associated with implementation of the proposed ELG rule by projecting a net increase in employment based on its myopic position of only estimating national level employment changes in the directly regulated electric power industry sector. Ignored in the Agency's analysis is the largest potential employment impact – i.e. any associated with other sectors of the economy, whereby the increased electric rates due to ELG compliance would make domestic manufacturers less competitive, leading to job losses from business shutdowns or moving of operations outside of the United States. The EPA attempts to sidestep this issue by generalizing that the net effect of an environmental regulation on regulated sectors and the overall economy as indeterminate. [50] Less discretionary income for all working Americans from higher electric rates due to ELG implementation would only compound employment losses due to lower demand for products and services. Put differently, EPA's narrow consideration of only including potential job creation by implementation of the ELG rule neglects the deleterious effects of job destruction that would likely result in a net loss of domestic employment. Before finalizing this rule, EPA must examine and identify the full impacts of the rule to domestic employment by including the impacts to all sectors of the economy in its modeling.

[50] Id. at 6-1.

8. Cost-Effectiveness Analysis

EPA's use of the time-value of money in 1981 dollars is inappropriate and a deliberate attempt to unfairly characterize the costs of compliance with the proposed rule as reasonable. The reported cost effectiveness of other guidelines should be escalated to current (2010) dollars in the time-value of money construct to demonstrate the magnitude of the real incremental cost that will be incurred and borne by a utility's customers, not masking these real costs in three decades old dollars.

J. Environmental Assessment

As justification for the ELG revisions, EPA claims that due to the reduction in effluent loadings that will result under the proposed ELG options, there will be a number of environmental and ecological improvements and reduced impact to wildlife and human receptors (78 FR at 34506). These improvements include reduced pollutant loadings to surface waters and sediments, reduced contaminant loadings to ground waters, fewer impacts to wildlife, reduced cancer and non-cancer health effects, reduced nutrient impacts, as well as numerous reductions in unquantifiable risks, such as the loading of bioaccumulative metals, sub-lethal chronic effects to aquatic life, impacts to wildlife population diversity, adverse health effects due to contaminated fish consumption and the potential for hazardous algal blooms. These benefits are summarized in the *Federal Register* notice and are further detailed in the agency's Environmental Assessment (EA).[51] However, these benefit claims are based on the presumption that there is current, ongoing harm to the environment and human health due to exposure to coal combustion-related pollutants.

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[51] EPA Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category," EPA-821-R-13-003, [hereinafter EPA Environmental Assessment], April 2013.

While certainly there have been cases of environmental damage due to the exposures listed above, the majority of the cases cited by EPA in its environmental assessment are not current or are mischaracterized and based on unsupported assumptions. For example, the agency states that,

> "The U.S. Environmental Protection Agency (EPA) did not find documented cases of human health impacts from coal combustion wastewaters. However, documented exceedances of drinking water maximum contaminant levels (MCLs) downstream of steam electric power plants and the issuance of fish advisories in receiving waters, indicate an ongoing human health concern."[52]

While exceedances of water quality standards or the issuance of fish advisories may be indicative of potentially harmful exposures to pollutants, they are not, in and of themselves, documentation of actual harm.

UWAG engaged Gradient Corp.[53] to review the agency's EA and found numerous examples where EPA,

- equated criteria exceedances with actual environmental damage,
- misrepresented damage case study findings when no case studies demonstrated adverse effects due to the pollutant in question,
- claimed widespread impact when the criteria exceedance and environmental harm were limited to a small number of power plants,
- mis-stated literature findings,
- failed to distinguish between sublethal and population-level effects, and
- emphasized damage from coal combustion material released prior to the promulgation of the existing ELGs.

[52] Id. at 24.

[53] Gradient Corp. Comments on Proposed Steam Electric Power Generating Effluent Guidelines. Prepared for Utility Water Act Group [hereinafter Gradient Corp.], September 5, 2013.

For example, EPA refers to "a number of studies performed in the 1970s and 1980s [outlining] *toxic impacts on ground water...*"[54] *These studies were performed prior to the establishment of* the existing ELGs in 1982 and are not relevant to the current evaluation of the industry. The agency also references locations where selenium in combustion wastewater discharges resulted in fish consumption advisories being issued for surface waters (for selenium). For example, a series of major fish kills occurred in 1978 and 1979 at Martin Lake (Texas) due to elevated concentrations of selenium in the water and fish tissue.[55] The EA cites ongoing adverse effects occurring within the lake, yet selenium discharges to the lake have been reduced and fish advisories remain in effect. The original selenium releases occurred before the promulgation of the current ELGs and the proposed ELG revisions will have no effect on the current situation in the lake.

1. **EPA must distinguish between population level impacts versus those that manifest themselves in individual organisms.**

In ecological risk assessment, it is important to distinguish between population level impacts versus those that manifest themselves in individual organisms. The goal of the Clean Water Act is to assure "the protection and propagation of a balanced population of shellfish, fish and wildlife."[56] But EPA only focuses on sub-lethal effects while population and community level impacts were not documented.[57]

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[54] EPA Environmental Assessment, April 2013.

[55] Id. at 3-1.

[56] US Congress. 2002. "Federal Water Pollution Control Act (as amended through P.L. 107-303, November 27, 2002)." 234p.

[57] Gradient Corp., September 5, 2013.

The Gradient report features many other examples of mis-statements and mis-characterizations of coal combustion material-related environmental impacts. AEP encourages EPA to carefully review this document and to note its conclusions.

2. **Adverse environmental harm, particularly to fish populations, is not always the outcome of coal combustion material exposure.**

The EPA EA contains many references, most of which document the alleged environmental and health effects of coal combustion related materials. However, there are very few references to studies which have demonstrated the lack of harm from such exposures. Many studies have been done which demonstrate that environmental harm, particularly to fish populations, is not always the outcome of coal combustion material exposure.[58,59,60,61,62,63,64,65,66,67] EPA is encouraged to review these studies and to incorporate their conclusions into the EA.

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[58] Loeffler, C., D. Miller, R. Shuman, D. Winter and P. Nelson. 1981. Arkansas River Threatened Fishes Survey. Performance Report SE-8-1. Colorado Division of Wildlife, Denver, CO.

[59] Loeffelman, P.H., J.H. Van Hassel. T.E. Arnold and J.C. Hendricks. 1985. *A new approach for regulating iron in water quality standards*. Aquatic Toxicology and Hazard Assessment: Eighth Symposium. ASTM STP 891. R.C. Bahner and D.J. Hansen. Eds., American Society for Testing and Materials, Philadelphia. Pp. 137-152.

[60] Van Hassel, J.H. and A. E. Gaulke. 1986. *Water Quality-based criteria for toxics: Site-specific water quality criteria from in-stream monitoring.* Environmental Toxicology and Chemistry. 5:417-426.

[61] Reash, R.J., J.H. Van Hassel and K.V. Wood. 1988. *Ecology of a southern Ohio stream receiving fly ash pond discharge: changes from acid mine drainage conditions.* Archives of Environmental Contamination and Toxicology. 17:543-554.

[62] Reash, R.J., T.W. Lohner, K.V. Wood and V.E. Willet. 1999. Ecotoxicological assessment of bluegill sunfish inhabiting a selenium-enriched fly ash stream. *Environmental Toxicology and Risk Assessment: Standardization of Biomarkers for Endocrine Disruption and Environmental Assessment: Eighth Volume, ASTM STP 1364*, D.S. Henshel, M.C. Black, and M.C. Harrass, Eds. American Society for Testing and materials, West Conshohocken, PA.

[63] Lohner, T.W., R.J. Reash, V.E. Willet and L.A. Rose. 2001. *Assessment of tolerant sunfish populations (Lepomis sp.) inhabiting selenium-laden coal ash effluents. 1. Hematological and population level assessment.* Ecotoxicology and Environmental Safety. 50:203-216.

This is not to say that coal combustion materials, under some circumstances, haven't caused environmental harm, but these studies demonstrate that exposure to these materials does not always lead to adverse environmental or human health effects.

Several electric utility companies have funded the Ohio River Ecological Research Program (ORERP),[68] which has been in existence for over 40 years and consists of fish, habitat, and water quality studies at multiple power plant sites on the main stem of the Ohio River. The program was initiated in 1970 to gather information on the potential impacts of power plant operation on Ohio River biota. The program was originally sponsored by ten electric utilities and the program has been managed by EPRI, a nonprofit organization that conducts research for the benefit of the public and its member companies for the past several years. Sampling includes seasonal night-time electrofishing and daytime beach seining at three upstream and three downstream locations near each plant. The long-term nature of the program allows for the establishment of aquatic community indices to support evaluations of technology performance, the collaborative development of compliance metrics, and the assessment of fish population trends.

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[64] Lohner, T.W., R.J. Reash, V.E. Willet and L.A. Rose. 2001. *Assessment of tolerant sunfish populations (Lepomis sp.) inhabiting selenium-laden coal ash effluents. 2. Tissue biochemistry and histochemical evaluation.* Ecotoxicology and Environmental Safety. 50:217-224.

[65] Lohner, T.W., R.J. Reash, V.E. Willet and L.A. Rose. 2001. *Assessment of tolerant sunfish populations (Lepomis sp.) inhabiting selenium-laden coal ash effluents. 3. Serum chemistry and fish health indicators.* Ecotoxicology and Environmental Safety. 50:225-232.

[66] Reash, R.J., T.W. Lohner, and K.V. Wood. 2006. *Selenium and other trace metals in fish inhabiting a fly ash stream: Implications for regulatory tissue thresholds.* Environ. Pollut. 142:397-408.

[67] DeForest, D.K., R. J. Reash and J.E. Tool. 2013. Comment on "Wildlife and the Coal Waste Policy Debate: Proposed Rules for Coal Waste Disposal Ignore Lessons from 45 years of Wildlife Poisoning." Environ. Sci. Technol. On-line at: http://pubs.acs.org/doi/abs/10.1021/es3053575?prevSearch=Comment%2Bon%2B%2BWildlife%2Band%2Bthe%2BCoal%2BWaste%2BPolicy%2BDebate&searchHistoryKey=

[68] The Ohio River Ecological Research Project: Long-term commitment yields important, credible ecological and operating knowledge. 2009. EPRI Journal. Pp. 15-17. Electric Power Research Institute. Palo Alto, CA.

The ORERP studies have demonstrated that the Ohio River fish community has improved in response to better water quality and that power plant fish entrainment, impingement, thermal discharges, and discharges of coal combustion residual wastewaters have had little or no measurable impact. These results have been documented in the peer-reviewed literature[69,70,71] and further document that exposure to coal combustion residual wastewaters does not always lead to environmental harm and damage. These results have been independently confirmed through the work of ORSANCO, which has also documented the results of its sampling programs in the peer-reviewed literature. More often than not, changes in habitat and weather affect fish populations in river systems more so than exposure to CCRs.

3. **"Gray" literature sources should not be used as the basis for the ELG rule revisions.**

In the appendix to the EA, EPA describes the methodology used to conduct a literature review to identify peer-reviewed journal articles that document environmental and human health impacts caused by steam electric discharges of the evaluated waste streams. The agency also searched for environmental assessments, impact studies, and related documents from state and federal governments. The literature search also involved collecting information from newspapers, environmental groups, industry organizations, and other non-peer-reviewed information sources. In the agency's own words, with which AEP agrees, "These sources are considered to be "gray literature" and are not acceptable forms of formal documentation of

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[69] Van Hassel, J. H., Reash, R. J., Brown, H. W., Thomas, J. L., & Mathews, R. C., Jr. (1988). *Distribution of upper and middle Ohio River fishes, 1973–1985: I. Associations with water quality and ecological variables.* Journal of Freshwater Ecology, 4(4), 441–458.

[70] Thomas, J.A., Emery, E.B., McCormick, F.H., (2005). *Detection of temporal trends in Ohio River fish assemblages based on lockchamber surveys (1957–2001).* In J.N. Rinne, R.M. Hughes, B. Calamusso, et al. (Eds.), Historical changes in large river fish assemblages of the Americas (pp. 431–449). Amer. Fish. Soc. Symp. 45.

[71] Lohner, T.W. and D. A. Dixon. 2013. *The value of long-term environmental monitoring programs: an Ohio River case study.* Environ. Monit. Assess. On-line at: http://www.springerlink.com/openurl.asp?genre=article&id=doi:10.1007/s10661-013-3258-4

environmental impact events," yet the agency still cited them in the EA. While it is true that these literature sources can provide an indication of potential areas of concern, they should not be considered as the basis for rulemakings such as the ELG revisions. As stated by EPA, "Often, an environmental event is reported in gray literature sources before it is well documented in peer-reviewed journals or government reports." Why then would the agency want to use such information as documentation for the supposed benefits of the ELG revisions?

According to EPA,

> "Table A-3 of the EA summarizes the number of documented surface water and ground water impact cases identified during the literature search and organized by power plant. Table A-4 and Table A-5 summarize the documented ground water impact cases from combustion residuals surface impoundments and landfills, respectively, identified during the literature search. Table A-6 and Table A-7 summarize the documented surface water impact cases from combustion residuals surface impoundments and landfills, respectively, identified during the literature search."[72]

However, based on its own admission, the results of the literature search, "are not acceptable forms of formal documentation of environmental impact events." Why then are they presented in the EA?

4. **AEP encourages the agency to remove its affiliated facilities from the list of alleged damage cases in the EA.**

AEP notes that twelve affiliated facilities were listed in the EA Appendix under one of more of the following damage case categories:

- Documented Impacts to Surface Water and Ground Water from Steam Electric Power Plant Discharges
- Documented Ground Water Damage Cases from Surface Impoundments.

[72] EPA Environmental Assessment, April 2013.

- Documented Ground Water Damage Cases from Landfills
- Documented Surface Water Damage Cases from Surface Impoundments Documented Surface Water Damage Cases from Landfills

While the agency's definition of "damage cases" may be different than the definition under RCRA (below), AEP is very concerned that its facilities have been listed on the premise of unacceptable forms of documentation.

Definition of Proven Damage Case –

(i) Documented exceedances of primary Maximum Contaminant Levels (MCLs) or other health-based standards measured in ground water at sufficient distance from the waste management unit to indicate that hazardous constituents have migrated to the extent that they could cause human health concerns, and/or

(ii) Where a scientific study demonstrates there is documented evidence of another type of damage to human health or the environment (e.g. ecological damage), and/or

(iii) Where there has been an administrative ruling or court decision with an explicit finding of specific damage to human health or the environment. In cases of co-management of CCWs with other industrial waste types, CCWs must be clearly implicated in the reported damage.

AEP and its partners have responded to these damage cases in the past and incorporate these responses by reference[73,74,75] and includes summaries of them in the appendix. To summarize, AEP believes that all of these cases should be removed from the EPA list of proven or potential damage cases. Site remediations, independent assessments by state agencies, and derivations of updated water quality criteria have confirmed that many of the damage cases should never have been listed by the agency or no longer meet the criteria as defined by the

[73] Comments on the proposed CCR rule by American Electric Power (AEP), filed November 15, 2010.

[74] American Electric Power's comments on USEPA's October 12, 2011 Notice of Data Availability (76 FR 63252 – 63257) regarding the disposal of coal combustion residuals, filed November 10, 2011.

[75] Response to Claims of Environmental Damage at the Clifty Creek Station. Madison, IN. Submitted by Indiana-Kentucky Electric Corporation, November 11, 2011.

agency. Differences in how to interpret the definition of "proven damage cases," a lack of documented population-level impacts, a lack of EPA approved fish tissue criteria, new monitoring data, and changes in plant operations have also lead to the conclusion that the damage cases should be removed from the agency's list. AEP encourages the agency to remove the company facilities from the list of proven damage cases in the EA.

Appendix 1

The following summaries were contained in AEP's comments to USEPA on the Notice of Data Availability regarding the proposed coal ash regulations, Docket ID No. EPA-HQ-RCRA-2011-0392. This information references the articles "Out of Control: Mounting Damages From Coal Ash Waste Sites", published by the Environmental Integrity Project and Earthjustice, and "In Harm's Way: Lack of Federal Coal Ash Regulations Endangers Americans and Their Environment", published by the Environmental Integrity Project, Earthjustice, and the Sierra Club.

John Amos Power Plant, Appalachian Power, Winfield, WV ("Out of Control", Site #30, Page 106)

- The John Amos Plant utilizes wet fly ash disposal for one of its three generating units. The fly ash slurry is pumped to a large headwaters impoundment. The treated fly ash decant water is discharged at Amos Plant Outfall 001 to Little Scary Creek, formerly a small tributary to the Kanawha River. Approximately 95% of Little Scary Creek's total flow is comprised of treated and decanted fly ash pond discharge. Little Scary Creek discharges to the Kanawha River upstream of Amos Plant.

- Earthjustice correctly cites that Little Scary Creek has approved site-specific criteria for two parameters: copper and selenium. The site-specific criterion for selenium (equal to the maximum outfall limitation) is 62 µg/L. Earthjustice claims that, for Little Scary Creek, "...there is also substantial evidence that aquatic life uses are being seriously degraded due to the disposal of fly ash in the headwaters of the creek." They cite high fish selenium tissue levels, obtained from WV DEP, as evidence of the degraded use.

- It should be noted that WV DEP has not adopted any numeric fish tissue criteria for selenium. U.S. EPA is not expected to finalize the revised aquatic life criteria for selenium until 2012. It is expected that the agency will propose a fish tissue (ovary) chronic aquatic life criterion, in conjunction with water concentration chronic criteria.

- There is evidence in the scientific literature that levels of selenium in freshwater fish can be high, but without significant population-level impacts. The company has published technical reports, specifically to Little Scary Creek, supporting this premise (Reash et al. 1999; Lohner et al. 2001).

- Appalachian Power Company has conducted numerous biological studies in Little Scary Creek, many of which were submitted to WV DEP in accordance with the facility's NPDES permit. Little Scary Creek supports a fairly diverse biological fauna despite the creek being comprised of almost entirely fly ash pond discharge water. A similar observation was reported for a stream in Ohio that was comprised of nearly 100% treated fly ash water (Reash et al. 1988). Neither WV DEP nor any other party has provided unequivocal evidence that the aquatic life use of Little Scary Creek is, or was previously, impaired.

- It is important to note that Amos Plant has changed the manner in which fly ash is disposed of. In August 2010, the one generating unit that was practicing wet ash disposal ceased sluicing fly ash to the fly ash impoundment. As such, Little Scary Creek no longer receives treated fly ash water and has returned to its original headwater stream characteristics.

- The EIP report states that the fly ash dam is ranked as a "high hazard". It is important to understand what that means. Using the criteria developed by the National Dam Safety Program (NDSP) for the National Inventory of Dams led by FEMA, the dam is ranked as "high hazard potential". A high hazard potential rating indicates that a failure will probably cause loss of human life; the rating is not an indication of the structural integrity of the unit or the possibility that a failure will occur in the future; it merely allows dam safety and other officials to determine where significant damage or loss of life may occur if there is a structural failure of the unit. It should be noted that there are an estimated 83,000 dams in the United States regulated by FEMA under the NDSP of which 14,000 dams are classified as "high hazard potential".

References

Lohner, T.W., R.J. Reash, V. E. Willet, and L.A. Rose. 2001. Assessment of tolerant sunfish populations (*Lepomis* sp.) inhabiting selenium-laden coal ash effluents: 1. Hematological and population-level assessment. *Ecotoxicology and Environmental Safety* 50: 203 – 216.

Reash, R.J., J.H. Van Hassel, and K.V. Wood. 1988. Ecology of a southern Ohio stream receiving fly ash pond discharge: changes from acid mine drainage conditions. *Archives of Environmental Contamination and Toxicology* 17: 543 – 554.

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Reash, R.J., T.W. Lohner, and K.V. Wood. 2006. Selenium and other trace metals in fish inhabiting a fly ash stream: implications for regulatory tissue thresholds. *Environmental Pollution* 142: 397 – 408.

U.S. EPA. 2004. Draft Aquatic Life Water Quality Criteria for Selenium. EPA-822-D-04-001. U.S. EPA Office of Water, Washington, DC.

Flint Creek Power Plant, Southwestern Electric Power Company, Gentry, AR
("In Harm's Way", Site #1, Page 1)

- Elevated concentrations of coal combustion byproducts constituents, selenium and sulfate, have been observed in groundwater monitoring wells located very close to the facility's landfill.

- The closest downgradient drinking water well is located on plant property about 1,670 feet west of the landfill. This well has been sampled and analyzed for primary MCLs (As, Ba, Cd, Cr, Se, Hg), action levels (Pb, Cu), and secondary standards (Ag, Fe, Mn, Zn). Results for all parameters were below their respective standard.

- Plant management has no reason to believe, nor is there any indication, that impacted groundwater has moved off company-owned property.

- Plant management is working with the Arkansas Department of Environmental Quality (ADEQ) and following a rigid regulatory process to determine the nature and extent of the CCB constituent migrations and what corrective measures may be needed, if any, to ensure continued protection of public health and the environment.

- A new leachate collection system has been designed, permitted, and constructed in the southeast corner of the landfill to properly collect and manage leachate that was discovered seeping from the waste material and entering an adjacent ditch that flows to the facility's bottom ash pond. This new leachate collection system began operating in January, 2010.

- The Company has completed the design of an intermediate liner and leachate collection system for the landfill and submitted that design to the ADEQ for approval. The new leachate collection system will allow for the effective collection and treatment of leachate generated from the facility. The new intermediate liner will stop recharge of the underlying groundwater from precipitation moving through the CCBs, eliminating the landfill as a source of CCB constituents to the groundwater.

- Groundwater monitoring wells have proactively been installed around the primary and secondary ash ponds.

Cardinal Plant, American Electric Power, Brilliant, OH
("In Harm's Way", Site # 23, Page 119)

- As the EIP report indicates, one of the Cardinal monitoring wells, S-2, is designated as a hydraulically "upstream", or upgradient monitoring well. However, due to the influence from previous surface mining activity and ash disposal operations, it is not appropriate to use the data from this well in comparisons to downgradient groundwater data. Groundwater data from monitoring well S-2 is not used in evaluating upgradient to downgradient groundwater quality.

- Monitoring well S-2 does have elevated levels of arsenic, boron, and molybdenum relative to the facility's unimpacted, upgradient shallow aquifer monitoring wells. It has not been established what the source is of elevated arsenic concentrations in monitoring well S-2. The monitoring well is located in an area where previous surface mining of coal occurred.

- Arsenic in the groundwater has been measured at levels higher than the EPA's Maximum Contaminant Level (MCL). Arsenic levels in the deeper Cow Run aquifer, which is hydraulically disconnected from the influence of ash leachate, have been observed at 0.41 mg/l. Arsenic in this aquifer is naturally occurring at levels 40 times that of the EPA MCL.

- The entire Morgantown groundwater aquifer is not contaminated although there are elevated concentrations of boron and molybdenum in monitoring wells located near the Flyash Reservoir 2 (FAR 2) dam, as well as to the east of the FAR 2 impoundment.

- Regarding the seeps to Blockhouse Hollow, those constitute groundwater being discharged from the Morgantown Aquifer. There are no seeps from the face of the FAR 2 dam itself.

- In 2010 the Company installed four additional groundwater monitoring wells to identify the nature and extent of elevated levels of boron and molybdenum in three different monitoring wells (M-11, M-21, and M-22). The Company is in the process of evaluating data from these monitoring wells as well as an identified seep in the valley sidewall of Blockhouse Hollow. Preliminary results indicate that there are no exceedances of EPA's MCLs for barium, cadmium, chromium, fluoride, lead, mercury, or selenium in any of the monitoring wells. There are exceedances of the EPA's MCL for arsenic however these exceedances are below the facility's inter-well prediction interval for arsenic and are likely attributable to naturally occurring arsenic concentrations. Upon completion of the evaluation an Assessment Monitoring Report will be submitted to Ohio EPA which summarizes the findings.

- The Tidd-Dale Subdivision is not in the direct path of groundwater flow from the FAR 2. Groundwater travel to the aquifer underlying the Tidd-Dale Subdivision, within which the referenced domestic wells are screened, is restricted by a shale aquitard. In addition to the restricted flow path, which limits groundwater flow from the FAR 2 to the aquifer underlying the Tidd-Dale Subdivision, significant natural attenuation within the lithology along the flow path reduces the risk of groundwater contamination to a deminimis level. A domestic drinking water well within the Tidd-Dale Subdivision was sampled and analyzed in April of 2011. The analyses of this sample indicated that there were no exceedances of EPA's MCLs for antimony, arsenic, barium, beryllium, cadmium, chromium, copper, cyanide, fluoride, lead, mercury, nitrate, nitrite, selenium, and thallium.

- The EIP report states that the dam is ranked as a "high hazard. It is important to understand what that means. Using the criteria developed by the National Dam Safety

- Program (NDSP) for the National Inventory of Dams led by FEMA, the dam is ranked as "high hazard potential". A high hazard potential rating indicates that a failure will probably cause loss of human life; the rating is not an indication of the structural integrity of the unit or the possibility that a failure will occur in the future; it merely allows dam safety and other officials to determine where significant damage or loss of life may occur if there is a structural failure of the unit. It should be noted that there are an estimated 83,000 dams in the United States regulated by FEMA under the NDSP of which 14,000 dams are classified as "high hazard potential".

Gavin Power Plant, Ohio Power Company, Cheshire, OH
("In Harm's Way", Site # 24, Page 124)

- The Gavin landfill footprint covers about 255 acres and is lined with 1.5 feet of clay with a permeability less than or equal to 1.0×10^{-7} cm/sec and a 30 mil polyvinyl chloride (PVC) geomembrane placed directly on top of the clay. Leachate is collected, analyzed, and treated prior to discharge under an NPDES permit.

- There have been statistically significant increases (SSIs) at downgradient wells for a few indicator parameters at the Gavin landfill. However, several other potential indicator parameters have not shown SSIs. Per Ohio EPA regulations, the SSIs are investigated through the implementation of an Assessment Monitoring Plan that is reviewed and approved by Ohio EPA. To date, all SSIs have been shown to be the result of natural groundwater variation, not the result of a release from the landfill.

- It is important to note that many types of coal mines - mapped/unmapped deep mines, auger mines, small-scale room and pillar mines, and strip mines - were present within the landfill footprint and are adjacent to the landfill and the fly ash pond. Several oil/gas wells were also drilled and operated within and adjacent to the landfill and fly ash pond footprints. Thus, the groundwater was highly degraded for decades prior to landfill/fly ash pond construction. In fact, the fly ash pond serves to collect and treat the surrounding acid mine drainage prior to discharge. If the fly ash pond was not available to treat this AMD, it would severely degrade Stingy Run and Kyger Creek to levels much worse than currently exist.

- The previous boron limit in the NPDES permit for the landfill leachate collection/treatment ponds discharge became outdated when Ohio EPA became aware of new scientific information. Based on the new information, Ohio EPA reviewed calculations and determined that the limit no longer was needed.

- Regarding the Outfall 001 (fly ash pond) toxicity tests, all tests run since September 2008 have shown no toxicity.

- Regarding the toxicity of the Outfall 008 discharge from landfill leachate treatment pond 2, there are no toxicity limits applied to this outfall, contrary to what EIP has reported.

- For landfill groundwater monitoring Well 94126, the EIP report is misleading, as groundwater monitoring well 94126 is an upgradient well in the Cow Run Sandstone - the uppermost aquifer that extends under the entire landfill, and not a downgradient monitoring well. Well 94126 does not reflect any impacts from the landfill, since it is upgradient. Barium concentrations in this upgradient monitoring well are extremely high coming onto the landfill environment with the highest being 13.8 mg/l (drinking water standard is 2 mg/l). Leachate from the landfill that is collected and that enters permitted ponds 1, 2 and 3, and this covers the entire 255-acre landfill, has never tested above 0.2 mg/l barium (over 115 analyses), a full order of magnitude less than the drinking water standard and almost two orders of magnitude less than the highest concentration in upgradient well 94126.

- Regarding groundwater monitoring well 9801, it is a monitoring well that is downgradient from Phase C in the Cow Run Sandstone aquifer, and about 2,000 feet downgradient from monitoring well 94126 which is also in the Cow Run. Barium concentrations exceed 2 mg/l but are not nearly as high as the concentrations seen in the upgradient monitoring well 94126. Again, raw leachate from the landfill has never exceeded 0.2 mg/l in over 115 analyses. The higher barium concentrations in Well 9801 are due to upgradient influences, not a release from the landfill.

- There are no structural integrity issues at the Gavin fly ash pond dam. Using the criteria developed by the National Dam Safety Program (NDSP) for the National Inventory of Dams led by FEMA, the dam is ranked as "high hazard". A high hazard potential rating indicates that a failure will probably cause loss of human life; the rating is not an indication of the structural integrity of the unit or the possibility that a failure will occur in the future; it merely allows dam safety and other officials to determine where significant damage or loss of life may occur if there is a structural failure of the unit. It should be noted that there are an estimated 83,000 dams in the United States regulated by FEMA under the NDSP of which 14,000 dams are classified as "high hazard potential".

- There are no slope stability issues at the Gavin landfill. The 3:1 outer slopes of the landfill were shown to be stable during the landfill permitting process meeting all OEPA factors of safety.

Muskingum River Plant, Ohio Power Company, Beverly, OH
("In Harm's Way", Site # 26, Page 144)

- There was a statistically significant increase (SSI) for alkalinity at one down gradient well (M-9603); however the other potential indicator parameters did not show any statistical significant increases (SSIs).

- To date, the SSI for alkalinity has been shown to be due to a natural groundwater variation, and not as a result of a release from the fly ash reservoir.

- In addition, based on an Ohio EPA Division of Groundwater guidance document, we did not believe that alkalinity was a good indicator parameter; therefore a request was made to Ohio EPA to revise the indicator parameter list to exclude alkalinity. Aside from alkalinity, existing groundwater data indicates that there has not been any release of CCB constituents to groundwater.

- On July 21, 2011 Ohio EPA confirmed through email correspondence that alkalinity can be dropped as an indicator parameter for groundwater contamination.

- Monitoring well OB-2, which EIP reported on, has been closed and abandoned since 2008 (See letter to ODNR sent 11/10/2008), and is not one of the monitoring wells sampled and reported to the Ohio EPA.

- Gross Alpha is not reported to Ohio EPA, and the maximum data point (128pCi/L) mentioned in the EIP report for well M-9612 appears to be a statistical outlier.

- The Pomeroy/Pittsburgh sandstone bedrock aquifer is a brackish aquifer. The total dissolved solids (TDS) in this aquifer range between 2,380 mg/L – 29,200 mg/L. Sampling groundwater in a brackish aquifer with increasing ionic contents tends to dissolve out minerals or constituents readily, hence we find TDS values that are above the MCL. However, these elevated values are not an accurate indicator of CCR constituent release.

- Ohio EPA was made aware of the high TDS concentrations in the Pomeroy/Pittsburgh aquifer, and on August 27, 2010 a report was sent to Ohio EPA requesting a modification to the indicator parameters that AEP analyzes and reports in the groundwater monitoring program.

- Muskingum River Plant made a request to Ohio EPA to include boron, bromide and molybdenum, which are better indicators of any release from fly ash, as opposed to using parameters that yield inconclusive results for evaluating subsurface geochemistry.

Northeastern Station, Public Service Company of Oklahoma, Oologah, OK ("In Harm's Way", Site # 27, Page 149)

- In September 2007, the Oklahoma DEQ directed the Company to establish a groundwater monitoring program for the facility's landfill.

- A groundwater monitoring program consisting of four monitoring wells around the landfill was established in February, 2008. Seeps from the embankment just south of the landfill (along the Verdigris River) were discovered. . During the summer of 2011, a barrier system was installed along the southern edge of the landfill to address the seeps.

- ODEQ requested additional monitoring wells in the Fall, 2008, after which twelve additional wells were installed.

- Analytical results show elevated concentrations of coal combustion byproduct constituent in the groundwater.

- Based on this information, ODEQ directed the Company to propose a plan and schedule for analyzing the potential release from the facility and for developing appropriate corrective measures

- Plant management is working with ODEQ and following a rigid regulatory process to determine the nature and extent of the CCB constituent migrations and what corrective measures may be necessary to assure continued protection of public health and the environment.

- A total of twenty-six monitoring wells have been installed around the fly ash landfill. *Quarterly groundwater monitoring and a nature and extent investigation are being* conducted.

- Only a localized groundwater flow pattern has been developed around the landfill. The current monitoring wells do not provide information about the groundwater flow pattern beyond the facility property line.

- The Company is committed to mitigating the impact of the stored fly ash to groundwater and the environment.

- The Company is designing an intermediate liner and leachate collection system for the landfill, which will be submitted to ODEQ for approval. The leachate collection system will allow for the effective collection and treatment of leachate generated from the facility. The intermediate liner will stop recharge of the underlying groundwater from precipitation moving through the CCBs, eliminating the landfill as a source of CCB constituents to the groundwater.

- Groundwater monitoring wells have been proactively installed around Northeastern's ash pond.

Clinch River Plant, Appalachian Power, Cleveland, VA
("In Harm's Way, Site # 36, Page 212)

- The case of reference happened almost 45 years ago in 1967. A dike surrounding a fly ash settling pond collapsed sending about 130 million gallons of fly ash laden water into the Clinch River. In effect, the Clinch River turned into a muddy flow with resulting ecological damage attributed to pH and severe loading of solids. This catastrophic event was determined by EPA to be a proven damage case and was listed as such in the February1988 "Report to Congress – Wastes from the Combustion of Coal by Electric Utility Power Plants" and in the August 9, 1993 Federal Register (58 FR 42446 – 42480).

- Such a catastrophic occurrence that occurred nearly 45 years ago is certainly not representative of results that can be found from current coal ash disposal practices nor

- was this incident the result of "surface runoff or leachate" in the sense contemplated by RCRA section 8002 (n). Extremely rare catastrophic occurrences such as this event should not be used as an industry-wide indictment on coal ash disposal practices nor should it be used to justify a hazardous waste listing for coal ash.

- The pond from which the spill occurred is no longer active. The stretch of the Clinch River affected by the spill has long since completely recovered and is now one of the few areas in the entire river where sensitive mussel populations are increasing rather than declining (Ahlstedt 2008).

- The Company worked with Virginia DEQ and U.S. Fish & Wildlife Service in studying plant discharges and appropriate protection for the river, culminating in construction of an advanced wastewater treatment plant in 1993 that has resulted in effluent water quality from Clinch River Plant that is overall superior to ambient river water.

Glen Lyn Plant, Appalachian Power, Glen Lyn, VA
("In Harm's Way, Site # 37, Page 217)

- The EIP report "In Harm's Way, Lack of Federal Coal Ash Regulations Endangers Americans and Their Environment" dated August 26, 2010, relies on very outdated information (late 70's – 1980).

- Discharge from the subject fly ash pond ceased in 1998. The plant has since converted to dry fly ash handling.

- More importantly, no toxicity was measured from the fly ash pond or the bottom ash pond. The cited studies show some differences in biotic communities upstream vs. downstream of the fly ash pond discharge, however no acute or chronic toxic effects were demonstrated.

- The cadmium and selenium water quality standards "violations" were not attributable to the ash pond effluent. The cited data were extracted from analyses that also show (but weren't mentioned) that upstream (uninfluenced) waters also commonly exceeded cadmium and selenium standards several fold. These samples were not collected and analyzed with appropriate quality controls to provide valid comparison against water quality standards.

- Valid effluent quality samples were collected on a recurring basis under the NPDES program, evaluated by Virginia DEQ, and found acceptable for meeting state water quality standards.

The following summaries are from AEP's comments to USEPA on the proposed coal ash regulations, Docket ID No. EPA-HQ-RCRA-2009-0640.

Welsh Plant, Southwestern Electric Power Company, Pittsburg, Texas

- The Welsh reservoir serves the Welsh electric generating plant and is a 1,465 acre cooling pond constructed in 1976. The pond originally received effluent from ash impoundments prior to 2000. The ash handling procedures were then modified to eliminate the discharge of decant water to the cooling reservoir. A consumption advisory for fish caught in the cooling pond was issued in 1992 stating that selenium concentrations in fish tissue exceeded a level of 2 mg/kg which was used, at that time, as the "standard." The derivation of this "standard" was questionable. A more scientific risk study prepared by the Texas Department of Health (TDH) entitled "Quantitative Risk Characterization, Welsh Reservoir, Titus County, Texas" dated September 29, 2003 established a health-based assessment comparison (HAC) for fish tissue residue concentration (TRC) of 6 mg selenium/kg of fish tissue. For all samples collected over 17 years, the mean selenium fish tissue concentration was 3.6 mg/kg with only one sample exceeding the 6 mg/kg TRC. Based on these data, the TDH concluded that the amount of selenium ingested from expected meal quantities is equivalent to unlimited consumption of fish from this reservoir. The selenium fish consumption advisory subsequently was lifted by the TDH on October 14, 2003. Based on the above discussion, this case should have never been listed as a proven damage case and should be removed from USEPA's list.

Pirkey Plant, Southwestern Electric Power Company, Hallsville, Texas

- A situation virtually identical to that of the Welsh reservoir is the Brandy Branch reservoir. This reservoir was built in 1983 and is a 1,257 acre cooling pond serving the Pirkey electric generating plant. Initially, coal pile runoff was discharged into the reservoir but was subsequently diverted to the flue gas desulfurization system. A fish consumption advisory was issued for the Brandy Branch reservoir in 1992 in conjunction with the advisory issued for the Welsh reservoir. Like Welsh, the advisory was based on the questionable "standard" of 2 mg/kg of fish tissue and, like Welsh, a more scientific risk study prepared by the Texas Department of Health (TDH) entitled "Quantitative Risk Characterization, Brandy Branch Reservoir, Harrison County, Texas" dated September 29, 2003 established a health-based assessment comparison (HAC) for fish tissue residue concentration (TRC) of 6 mg selenium/kg of fish tissue. The mean selenium concentration for fish tissue in samples collected from the Brandy Branch reservoir over 17 years was 2.23 mg/kg. The highest mean never exceeded the TRC. The TDH again concluded that the amount of selenium ingested from expected meal quantities is equivalent to unlimited consumption of fish from the Brandy Branch reservoir. The 1992 fish consumption advisory was lifted by TDH on October 14, 2003 based on the more accurate and scientific risk characterization described above. Based on the above facts.

this case should have never been listed as a proven damage case and it too should be removed from USEPA's damage case list.

<u>Conesville Plant, Ohio Power Company, Conesville, Ohio</u>

- The Conesville Fixed FGD Sludge landfill was constructed in 1976 and covered about 50 acres. It was closed, capped, and seeded in 1988, almost 23 years ago. Groundwater monitoring data from 34 groundwater monitoring wells around this facility when it was active had been analyzed by USEPA pursuant to the 1988 Report to Congress. From analyzing two sets of groundwater data, USEPA identified exceedances of Primary Drinking Water Standards (PDWS) for arsenic, cadmium, selenium, and chromium. USEPA stated that the selenium exceedances were due to upgradient sources. Arsenic and cadmium were present in on-site wells only. Lead and chromium were the only metals that exceeded the PDWS in off-site wells. Shortly thereafter, the filtrate from the FGD sludge stabilization process, believed to be a possible source of cadmium, was routed to the thickener tanks. Subsequently, groundwater monitoring was performed for an additional six years. Results indicated that only one of 482 samples for arsenic exceeded the PDWS. Only six of 520 samples exceeded the PDWS for chromium, and *five of the six exceedances occurred on one of the 25 sampling events.* Seventeen of 582 samples exceeded the PDWS for lead, and all of those exceedances occurred on three of the 25 sampling events. No samples exceeded the cadmium PDWS. Based on the above data, along with USEPA's statement that there is limited potential for off-site migration of contaminants (and the fact that this landfill has been closed and capped for almost 23 years) this site should be removed from USEPA's list of potential damage cases.

Appendix 2

Response to Claims of Environmental Damage at the Clifty Creek Station-Madison, Indiana. Prepared in response to: Earthjustice, Clean Air Task Force *et al.*, U.S. EPA's Coal Combustion Residual Assessment Notice of Data Availability, 76 Fed. Reg. 63252 (October 12, 2011), Docket No. EPA-HQ-RCRA-2009-0640, Pages 23 & 24

The following summary was contained in the Indiana-Kentucky Electric Corporation's (IKEC) response to the alleged damage claim cited against the Clifty Creek Station by the Environmental Integrity Project and Earthjustice in their publication *"Out of Control" (pgs. 23-24).*

In the Summary Section of the "Damage Claim" it is claimed that. "Clifty Creek Station's CCW Landfill has measured high levels of boron, manganese, iron, and sulfate in downgradient groundwater." In addition, it is claimed that, "The extent of the plume has not been determined."

Given the criteria that the U.S. EPA uses for defining a proven Damage Case, there needs to be: (i) documented exceedances of a primary MCLs or other health-based standards measured in groundwater at a sufficient distance from the waste management unit to indicate that hazardous constituents have migrated to the extent that they could cause human health concerns (but not secondary MCL standards), and/or; (ii) where a scientific study demonstrates there is documented evidence of another type of damage to human health or the environment (e.g., ecological damage)[76], and/or; (iii) where there has been an administrative ruling or court decision with an explicit finding of specific damage to human health or the environment.

IKEC points out that National Secondary Drinking Water Regulations (NSDWRs or secondary standards) are not health-based standards. Instead, they are non-enforceable guidelines regulating contaminants that may cause cosmetic effects (such as skin or tooth discoloration) or aesthetic effects (such as taste, odor, or color) in drinking water. U.S. EPA recommends secondary standards to water systems but does not require systems to comply.

IKEC submits that there are no documented exceedances of a primary MCL or other health-based standards at this site, nor is there any evidence to indicate that there is any migration of any parameter off the site that is contributing to any exceedances of the secondary MCLs in the nearby off-site receptors. To the contrary, we have both scientific investigations, (in the form of comprehensive groundwater monitoring assessments performed by competent and qualified professional hydrogeologists) as well as a court decision also referenced in the damage case claim that verify this.

The groundwater monitoring assessments were initiated by Applied Geology and Environmental Science (AGES), Inc.. in 2004, when they began a hydrogeologic investigation at the site that included the installation of 28 piezometers, the drilling of 16 soil borings, surveying, and several

[76] In determining whether evidence of ecological damage from a CCR unit constitutes a damage case, U.S. EPA stated in the proposed 2010 CCR rulemaking that it "now believes that ecological damages warranting state environmental response are generally appropriate for inclusion as a damage case," such as information leading a state to issue fish advisories. 75 Fed. Reg. 35128, 35147 (June 21, 2010).

years of water level monitoring. The results of the investigation indicate that groundwater from the northern end of the landfill discharges to the on-site West Bottom Ash Pond or the West Branch of Clifty Creek before flowing into the Ohio River. According to the report, the West Branch of Clifty Creek, Clifty Creek and the Ohio River are extremely effective hydraulic barriers to eastward groundwater flow toward the Madison Well Fields, which are located one-half (0.5) to three (3) miles upstream from the landfill.[77]

Based on their study, AGES determined that it is not feasible for groundwater from this portion of the landfill to affect the Madison Well Fields because all groundwater from the site discharges to the Ohio River, which flows to west/southwest, away from the Madison Well Fields. In addition, the minimal volume of groundwater discharging from the entire site is diluted in the Ohio River by a factor of approximately 720,000 to over 1,500,000. At this rate of dilution, constituents in groundwater from the site would be undetectable with standard analytical methods.

In conclusion, based on the extensive hydrogeologic studies conducted at this site, it is not feasible for groundwater from the site to affect groundwater at any nearby municipal water supply well fields due to the minimal volume of groundwater leaving the site, the hydraulic barriers present, and the level of dilution provided by the Ohio River. Additionally, the two municipal drinking water supply well fields that are the closest off-site receptors that would be impacted by any off-site migration of groundwater from the Clifty Creek landfill operations undergo regular testing. These two well fields include the Madison Well Fields and the Kent Well Fields (one upstream and one downstream) and both public water supplies have demonstrated that the water consistently meets all applicable regulatory requirements, and shows no trace of contamination associated with the Clifty Creek landfill site.

Given the specific conclusion contained in the AGES study that, "Based on hydrogeologic conditions in the area, it is not possible for groundwater from the site to adversely impact supply wells at the Madison Well Fields or the Kent Water Company Well Fields", combined with the actual monitoring data available, it is IKEC's conclusion that the site presents no risk to the Madison Well Field, the Kent Well field, any other municipal well field, or any other domestic drinking water wells.

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[77] Applied Geology and Environmental Science (AGES), Inc., (2006). Evaluation of Potential Risk to Supply Well Fields, Indiana-Kentucky Electric Corporation, Clifty Creek Station, June 2006.

SC 11

OHIO POWER COMPANY'S RESPONSES TO
SIERRA CLUB'S DISCOVERY REQUESTS
PUCO CASE NO. 14-1693-EL-RDR
SIXTH SET

INTERROGATORY

INT-6-157 Refer to page 8 lines 1 through 17 of the testimony of John McManus in support of the Amended Application.

a. For each of the PPA Units, explain how each of the following coal combustion residuals are currently processed and disposed of:

i. Fly ash

ii. Bottom ash

iii. FGD waste

b. For each of the PPA Units that has a surface impoundment, state whether poundment is currently lined.

c. For each of the PPA Units, identify any waste water treatment processes that are currently used at the unit.

d. With regards to the "analysis currently underway to determine the necessary modifications to the PPA Rider Units' surface impoundments required by the CCR Rule":

i. State whether such analysis has been completed

1. If not, explain when such analysis is expected to be completed

ii. State what AEP corporate entity is undertaking such analysis.

iii. Identify, by name, position, and employer, who is involved in such analysis.

RESPONSE

a.i. Conesville Units 4, 5 & 6 - Wet sluiced to the plant's surface impoundment during startup. The majority is collected dry, used to fixate FGD byproduct, and disposed in the plant's landfill. That is the disposal operation. There also is some beneficial use of the product.

Cardinal Unit 1 – Wet sluiced to the plant's surface impoundment.

Clifty Creek Units 1, 2, 3, 4, 5, & 6 – Collected dry and disposed in the plant's landfill.

Kyger Creek Units 1, 2, 3, 4, & 5 – Wet sluiced to the plant's surface impoundment.

Stuart Units 1, 2, 3, & 4 – Wet sluiced to the plant's surface impoundment.

Zimmer Unit 1 – Fly ash is managed dry at Zimmer Station. Much of it is sold. What is not sold is disposed in an off-site station landfill.

ii. For all PPA Units except Zimmer Plant the bottom ash is wet sluiced to an ash pond. On occasion some of these ash ponds may be excavated and the bottom ash disposed in the landfill. That is the disposal operation. There also is some beneficial use of the product. At Zimmer Plant the bottom ash is managed dry and disposed in an offsite station landfill. Some bottom ash is subsequently "mined" at the landfill for beneficial reuse.

PENGAD 800-631-6989
EXHIBIT
SC-11

INT-6-157 Continued

iii. Conesville Units 4, 5 & 6 – The FGD waste from Conesville Units 5 and 6 is fixated with flyash and lime and then disposed in the plant's landfill. The FGD waste from Conesville Unit 4 is a drier material which is directly disposed in the plant's landfill. Those are the disposal operations. There also is some beneficial use of these products.

Cardinal Unit 1 – Disposed in the plant landfill. This is the disposal operation. There is also some beneficial use of this product.

Clifty Creek Units 1, 2, 3, 4, 5, & 6 – Disposed in the plant landfill.

Kyger Creek Units 1, 2, 3, 4, & 5 – Disposed in the plant landfill. This is the disposal operation. There is also some beneficial use of this product.

Stuart Units 1, 2, 3, & 4 – The FGD systems produce gypsum that when it meets product specification is provided for beneficial use. Excess material or material that does not meet product specifications is landfilled offsite. Stuart plant is in the process of building an onsite landfill to meet disposal requirements moving forward. These are the disposal operations. There is also some beneficial use of this product.

Zimmer Unit 1 – On-spec FGD gypsum (from a wet scrubber system) is beneficially reused offsite. Off-spec waste gypsum is disposed in the offsite station landfill.

b. The CCR Rule requires that an owner or operator of an existing CCR surface impoundment must document whether or not such unit was constructed with a liner, as defined by the CCR Rule, by October 19, 2016. The analysis necessary to make this determination for the PPA Rider units is on-going and will be completed in accordance with the timeline identified by the CCR Rule.

c. Conesville Units 4, 5 & 6 – All wastewater is treated via the bottom ash/wastewater settling pond complex prior to discharge. Prior to discharge into the pond, the blowdown from the Unit 4 FGD system is treated in a wastewater treatment plant (WWTP) that consists of chemical precipitation (including organosulfide chemical addition to promote mercury settling), coagulation, sedimentation, filtration and pH adjustment.

Cardinal Unit 1 – Bottom ash and other miscellaneous plant wastewaters are treated via settling in the bottom ash/wastewater settling pond complex. Water from the pond is recirculated as fly ash sluice water which receives treatment via settling in Fly Ash Reservoir II prior to discharge. Blowdown from the Unit 1 FGD system is treated in a WWTP that consists of chemical precipitation (including organosulfide chemical addition to promote mercury settling), coagulation, sedimentation, filtration and pH adjustment.

Clifty Creek Units 1, 2, 3, 4, 5, & 6 – All wastewaters generated by the Clifty Creek Plant is treated in the plant's boiler slag pond complex prior to discharging prior to discharging through the impoundment's NPDES outfall. All FGD system-related wastewaters are treated by the plant's FGD WWTP prior to entering the boiler slag pond complex. Treatment in the WWTP

INT-6-157 Continued

includes pH adjustment, coagulation, sedimentation, filtration, and chemical precipitation (including organosulfide to promote mercury settling).

Kyger Creek Units 1, 2, 3, 4, & 5 – All wastewaters generated by the Kyger Creek Plant are treated in the plant's boiler slag pond and fly ash pond complexes prior to discharging through the impoundments' NPDES outfalls. All FGD system-related wastewaters are treated by the plant's FGD wastewater treatment plant prior to entering the fly ash pond complex. Treatment in the WWTP includes pH adjustment, coagulation, sedimentation, filtration, and chemical precipitation (including organosulfide to promote mercury settling).

Stuart Units 1, 2, 3, & 4 – All four units discharge bottom ash to a single bottom ash pond. The wastewater from this pond is treated through sedimentation and solids filtration. FGD wastewater is also discharged to this pond, and mercury treatment will be in operation by February, 2016. The fly ash ponds discharge through a single outfall and the wastewater is treated with sedimentation, pH neutralization and hexavalent chromium reduction prior to discharge.

Zimmer Unit 1 – There are no fly ash transport waters at Zimmer Station. Bottom ash transport waters are managed in a hydrobin system and recycled. The collected bottom ash is taken to the offsite station landfill. FGD wastewaters (from a wet scrubber system) are treated in an onsite advanced physicochemical wastewater treatment system and then discharged to the Ohio River. Low volume and other non-CCR wastewaters are managed in non-CCR impoundments and discharged to the Ohio River.

d.i. Please see the Company's response to OCC-INT-5-159.

1. Please see the Company's response to OCC-INT-5-160.

ii. The AEPSC Engineering Department, The Projects and Controls Department and the Environmental Services Department is undertaking the analyses working with consultants, for the Conesville and Cardinal Plants. For the Clifty Creek and Kyger Creek Plants, OVEC is working on these projects with their own consultants. Similarly, Dynegy for Zimmer and Dayton Power and Light for Stuart are working on the projects for these plants.

iii. The Company objects to this request seeking information regarding preparation of draft testimony as being information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Further, the Company objects to this request to the extent it seeks information regarding the preparation of testimony that is confidential and privileged in connection with trial preparation, as the testimony was prepared under the direction of counsel for purposes of this regulatory proceeding. Without waiving the foregoing objection(s) or any general objection the Company may have, the Company states that Company Witness McManus is personally responsible for the statements made in his testimony and for explaining and defending the contents therein.

Prepared by: John M. McManus

SC
12

ANNUAL REPORT — 2014

OHIO VALLEY ELECTRIC CORPORATION

and subsidiary

INDIANA-KENTUCKY ELECTRIC CORPORATION

EXHIBIT
SC-12
PENGAD 800-631-6989

Ohio Valley Electric Corporation

GENERAL OFFICES, 3932 U.S. Route 23, Piketon, Ohio 45661

Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies, were organized on October 1, 1952. The Companies were formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies for the purpose of providing the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission (AEC) near Portsmouth, Ohio.

OVEC, AEC and OVEC's owners or their utility-company affiliates (called Sponsoring Companies) entered into power agreements to ensure the availability of the AEC's substantial power requirements. On October 15, 1952, OVEC and AEC executed a 25-year agreement, which was later extended through December 31, 2005 under a Department of Energy (DOE) Power Agreement. On September 29, 2000, the DOE gave OVEC notice of cancellation of the DOE Power Agreement. On April 30, 2003, the DOE Power Agreement terminated in accordance with the notice of cancellation.

OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. The Sponsoring Companies and OVEC entered into an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040.

OVEC's Kyger Creek Plant at Cheshire, Ohio, and IKEC's Clifty Creek Plant at Madison, Indiana, have nameplate generating capacities of 1,086,300 and 1,303,560 kilowatts, respectively. These two generating stations, both of which began operation in 1955, are connected by a network of 705 circuit miles of 345,000-volt transmission lines. These lines also interconnect with the major power transmission networks of several of the utilities serving the area.

The current Shareholders and their respective percentages of equity in OVEC are:

Allegheny Energy, Inc.[1]	3.50
American Electric Power Company, Inc.*	39.17
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Ohio Edison Company[1]	0.85
Ohio Power Company**[6]	4.30
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
The Toledo Edison Company[1]	4.00
	100.00

These investor-owned utilities and affiliates of generation and transmission rural electric cooperatives comprise the Sponsoring Companies and currently share the OVEC power participation benefits and requirements in the following percentages:

Allegheny Energy Supply Company LLC[1]	3.01
Appalachian Power Company[6]	15.69
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
FirstEnergy Solutions Corp.[1]	4.85
Indiana Michigan Power Company[6]	7.85
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Monongahela Power Company[1]	0.49
Ohio Power Company[6]	19.93
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
	100.00

Some of the Common Stock issued in the name of:

*American Gas & Electric Company
**Columbus and Southern Ohio Electric Company

Subsidiary or affiliate of:

[1]FirstEnergy Corp.
[2]Buckeye Power, Inc.
[3]The AES Corporation
[4]Duke Energy Corporation
[5]PPL Corporation
[6]American Electric Power Company, Inc.
[7]Wolverine Power Supply Cooperative, Inc.
[8]Vectren Corporation

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

A Message from the President

Ohio Valley Electric Corporation and its subsidiary, Indiana-Kentucky Electric Corporation, are making fundamental changes to the organization and the operation of the facilities to strive to be the energy provider of choice for the Sponsoring Companies. These fundamental changes include developing and using the skills, knowledge and culture improvement of our dedicated employees to elevate their performance toward first-decile goals. We expect these changes will produce the operational, financial and human performance results that will ensure OVEC-IKEC can continue to be an economical energy resource during these challenging times in our industry.

SAFETY

OVEC and IKEC are committed to providing a safe and healthy place to work for all employees. In 2014, the Companies continued making progress on their transition to a culture that leads with safety through continued training on human performance improvement tools originally initiated in 2012. As a direct result of these efforts, OVEC and IKEC experienced their best safety performance on record in 2014. Strong leadership and the involvement of all employees and our contractors will help ensure that we ultimately achieve and sustain the desired goal of zero harm.

ENERGY SALES

OVEC's use factor — the ratio of power scheduled by the Sponsoring Companies to power available — for the combined on- and off-peak periods averaged 86.5 percent in 2014 compared with 75.1 percent in 2013. The on-peak use factor averaged 96.2 percent in 2014 compared with 89.0 percent in 2013. The off-peak use factor averaged 74.1 percent in 2014 and 57.4 percent in 2013.

In 2014, OVEC delivered 11.2 million megawatt hours (MWh) to the Sponsoring Companies under the terms of the Inter-Company Power Agreement compared with 10.3 million MWh delivered in 2013.

POWER COSTS

In 2014, OVEC's average power cost to the Sponsoring Companies was \$56.382 per MWh compared with \$65.183 per MWh in 2013. The total Sponsoring Company power costs were \$631 million in 2014 compared with \$672 million in 2013. The 2014 increased energy sales, due in part to lower winter temperatures and higher natural gas prices combined with significant cost control measures, resulted in the lowest average power cost since 2011.

2015 ENERGY SALES OUTLOOK

In 2015, the demand for energy is expected to remain at levels comparable to 2014. As a result, OVEC anticipates the combined use factor for 2015 will be approximately 81 percent, which will result in energy sales estimated at 11 million MWh and average power costs of approximately \$56 per MWh.

COST CONTROL INITIATIVES

In 2014, OVEC and IKEC employees expanded the cost control focus to target specific functions in an effort to reduce costs and improve efficiencies through process improvements. These activities continue to improve the OVEC cost profile, the plant operation results and the physical work environment. The OVEC and IKEC employees are the driving force behind this culture change that will ensure that these continuous improvement efforts are sustainable.

FLUE GAS DESULFURIZATION (FGD) PROJECTS AND ENVIRONMENTAL COMPLIANCE OBLIGATIONS

The two FGD scrubbers at Kyger Creek were successfully placed into service in November 2011 and February 2012. The two Clifty Creek plant FGD systems were successfully placed into service in March 2013 and May 2013. All four scrubbers have demonstrated that they can meet our environmental performance expectations. The pollution control systems installed at both plants are capable of meeting emission limitations under the

Mercury and Air Toxics Standards (MATS), which became effective in April 2015, as well as the Cross-State Air Pollution Rule (CSAPR), which went into effect on January 1, 2015.

OVEC and IKEC have a strong commitment to maintain compliance with all applicable federal, state and local environmental rules and regulations. During 2014, the Kyger Creek and Clifty Creek plants operated in compliance with their respective air emission limits. IKEC did receive one Notice of Violation for failing to adequately document fugitive dust control measures, and the issue has been resolved and appropriate corrective actions implemented. In addition, we continue to market the gypsum generated from our new scrubber operations as an agricultural soil amendment in Ohio and anticipate expanding that to Indiana in the coming year. Finally, we also initiated actions to meet boiler tuning and optimization obligations under MATS; prepared for the initiation of studies necessary to demonstrate compliance with aquatic life impingement and entrainment requirements under Clean Water Act, Section 316(b) regulations; and initiated actions necessary to prepare for Coal Combustion Residual regulations that were signed by the U.S. EPA Administrator in late 2014.

OVEC FERC Order 1000 Compliance

The Federal Energy Regulatory Commission (FERC) Order 1000 issued in July 2011 requires transmission providers, including OVEC, to participate in regional and interregional transmission planning processes. Because OVEC is not a member of a Regional Transmission Organization (RTO) that provides such planning to its members, OVEC partnered with LG&E/KU to join the Southeast Regional Transmission Planning (SERTP) group. The SERTP had been formed in 2007 by a group of utilities led by Southern Company. Working with this group, OVEC was able to comply with Order 1000 by implementing the regional processes on June 1, 2014. On January 14, 2014, OVEC and its SERTP partners filed revisions to correct the issues identified by FERC in its July 18, 2013, order. FERC issued an order on April 13, 2015, accepting in part and denying in part the revisions submitted and directing specific changes to OVEC's and its SERTP partners' tariffs within 30 days. This filing was made on May 12, 2015. FERC also issued an order on January 23, 2015, accepting in part and denying in part the interregional portion of the filing. The SERTP jurisdictional entities filed revisions for interregional coordination with the non-RTO seams on March 24, 2015, and simultaneously requested a 60-day extension to resolve outstanding issues with regard to the RTO seams, which was granted. Interregional filings for the RTO seams were made on May 26, 2015, for the PJM seam and will be made on June 22, 2015, for the MISO seam. A ruling on these filings is expected later this fall.

DOE Arrangements with OVEC

In 2014, OVEC purchased 242,638 MWh of power and energy from other electricity suppliers for delivery and use by the Department of Energy (DOE) for its Portsmouth facility. At the request of the DOE, OVEC makes these limited purchases of power and energy under the terms and conditions of an Arranged Power Agreement (APA) entered into in 2003 with the DOE.

As ordered by the FERC, the North American Electric Reliability Corporation (NERC) registered OVEC as the load-serving entity for the DOE load at the Portsmouth facility. OVEC has worked with the OVEC Operating Committee to implement procedures to mitigate any impacts, other than additional NERC compliance obligations, that could result from this NERC registration and to protect the Sponsors' rights to all of OVEC's generation.

On September 2, 2014, OVEC informed the DOE of its desire to no longer continue to provide the services outlined in the APA. OVEC advised the DOE that continuing with this arrangement is inconsistent with OVEC's goal of being the provider of choice for the Sponsors. OVEC further pointed out to the DOE that the utility industry has changed substantially since the existing arrangements were put into place and that they now had other options available to them to procure these services in a more economic manner from entities for whom such services are part of their core competencies. The DOE agreed to work with OVEC to transition away from the APA. The original goal was to have the APA terminated by May 31, 2015. Throughout this time, OVEC has been working with DOE to address details necessary to allow as seamless a transition as possible. The DOE has requested an additional 60 days to finish working on these details. OVEC has agreed to this extension, with the expectation that the APA will terminate on July 31, 2015. On April 28, 2015, both OVEC and the DOE signed an agreement to terminate the APA on July 31, 2015. On May 7, 2015, an application was filed with the Public Utilities Commission of Ohio outlining

OVEC's and DOE's mutual desire to terminate the APA effective as of midnight on July 31, 2015. This termination will also remove the load-serving entity obligation ordered by FERC in 2012.

Separate from the APA termination, OVEC has been negotiating with the DOE on an agreement to provide transmission support and other services related to NERC compliance, which OVEC had been providing as part of the APA.

Barring additional delays, on July 31, 2015, OVEC will have successfully ended its 60-plus year power supply relationship with the DOE.

PSEUDO-TIE OF PJM SPONSORS' SHARES OF OVEC-IKEC GENERATION

On February 27, 2014, the OVEC Operating Committee voted to approve the pseudo-tie of the PJM Sponsors' shares of OVEC's generation into the PJM market in order to comply with new market rules instituted by PJM. This will place those shares under the dispatch control of PJM. The implementation was to be completed by June 1, 2017. On March 27, 2015, in response to other market changes in PJM, the OVEC Operating Committee agreed to advance the implementation by one year to June 1, 2016. Working through the Operating Committee, OVEC has been writing a cost development document and other procedures to enable OVEC to become the market interface for the PJM Sponsors. OVEC continues to work with its Energy Management System vendor and PJM to implement the necessary changes to meet the challenge of enabling operation of the pseudo-tie functionality by June 1, 2016, while continuing to assure delivery of the non-PJM Sponsors' shares under existing scheduling procedures.

BOARD OF DIRECTORS AND OFFICER CHANGES

In July 2014, Wayne D. Games, vice president – power supply of Vectren Corporation, was elected to serve as a director of OVEC. Also in July 2014, David A. Lucas, vice president finance of Indiana Michigan Power, was elected to serve as a director of IKEC. In January 2015, John A. Verderame, managing director of power trading and dispatch of Duke Energy Corporation, was elected a director of OVEC, and in June 2015, he was appointed to the Executive Committee of OVEC. He succeeded Charles Whitlock, who had served on the OVEC board and as a member of the Executive Committee since 2006. In June 2015, Robert P. Powers, executive vice president and chief operating officer of American Electric Power Company, Inc., was appointed to the Executive Committee of OVEC.

Also in June 2015, Justin J. Cooper was elected assistant secretary of OVEC and IKEC.

Nicholas K. Akins
President

June 17, 2015

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS AS OF DECEMBER 31, 2014 AND 2013

ASSETS	2014	2013
ELECTRIC PLANT:		
At original cost	$2,706,385,652	$2,671,807,219
Less—accumulated provisions for depreciation	1,245,490,373	1,182,491,224
	1,460,895,279	1,489,315,995
Construction in progress	15,329,947	30,583,795
Total electric plant	1,476,225,226	1,519,899,790
CURRENT ASSETS:		
Cash and cash equivalents	43,453,966	70,757,710
Accounts receivable	40,001,960	35,332,653
Fuel in storage	44,335,429	43,020,394
Materials and supplies	34,499,713	32,564,435
Property taxes applicable to future years	2,780,000	2,702,905
Emission allowances	-	62,428
Deferred tax assets	4,237,801	9,980,768
Income taxes receivable	-	3,331,536
Regulatory assets	-	371,297
Prepaid expenses and other	2,208,613	2,244,413
Total current assets	171,517,482	200,368,539
REGULATORY ASSETS:		
Unrecognized postemployment benefits	1,437,151	2,078,864
Pension benefits	32,475,646	8,542,293
Income taxes billable to customers	1,036,268	-
Total regulatory assets	34,949,065	10,621,157
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	12,258,005	13,401,209
Deferred tax assets	-	19,432,479
Long-term investments	122,502,773	117,106,668
Other	120,877	488,407
Total deferred charges and other	134,881,655	150,428,763
TOTAL	$1,817,573,428	$1,881,318,249

(Continued)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS AS OF DECEMBER 31, 2014 AND 2013

CAPITALIZATION AND LIABILITIES	2014	2013
CAPITALIZATION:		
Common stock, $100 par value—authorized, 300,000 shares; outstanding, 100,000 shares in 2014 and 2013	$ 10,000,000	$ 10,000,000
Long-term debt	1,274,895,961	1,267,873,554
Line of credit borrowings	20,000,000	30,000,000
Retained earnings	7,031,723	6,478,234
Total capitalization	1,311,927,684	1,314,351,788
CURRENT LIABILITIES:		
Current portion of long-term debt	243,000,194	290,496,381
Accounts payable	54,104,896	50,131,367
Accrued other taxes	9,410,141	9,062,813
Regulatory liabilities	14,065,394	27,406,208
Accrued interest and other	23,614,552	28,145,464
Total current liabilities	344,195,177	405,242,233
COMMITMENTS AND CONTINGENCIES (Notes 3, 11, 12)		
REGULATORY LIABILITIES:		
Postretirement benefits	33,650,545	32,619,457
Decommissioning and demolition	14,102,619	19,140,730
Investment tax credits	-	3,393,146
Net antitrust settlement	-	1,823,929
Income taxes refundable to customers	-	28,380,282
Total regulatory liabilities	47,753,164	85,357,544
OTHER LIABILITIES:		
Pension liability	32,475,646	8,542,293
Deferred tax liability	4,237,801	-
Asset retirement obligations	29,547,185	22,230,109
Postretirement benefits obligation	44,875,752	42,173,401
Postemployment benefits obligation	1,437,151	2,078,864
Other noncurrent liabilities	1,123,868	1,342,017
Total other liabilities	113,697,403	76,366,684
TOTAL	$1,817,573,428	$1,881,318,249

See notes to consolidated financial statements.

(Concluded)

OHIO VALLEY ELECTRIC CORPORATION
AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS
FOR THE YEARS ENDED DECEMBER 31, 2014 AND 2013

	2014	2013
OPERATING REVENUES—Sales of electric energy to:		
Department of Energy	$ 11,758.386	$ 9,281,567
Sponsoring Companies	644,415.791	666,367,706
Total operating revenues	656,174,177	675,649,273
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	315,460.920	311,899,995
Purchased power	11.180.650	8,763,157
Other operation	92,885.913	98,197,470
Maintenance	90,766,181	83,396,811
Depreciation	65,179,764	80,172,750
Taxes—other than income taxes	12,094,519	11,421,154
Income taxes	331.834	890.377
Total operating expenses	587.899,781	594,741.714
OPERATING INCOME	68.274.396	80,907.559
OTHER INCOME	9,888.500	530,109
INCOME BEFORE INTEREST CHARGES	78,162.896	81.437,668
INTEREST CHARGES:		
Amortization of debt expense	5,075,785	5,166,736
Interest expense	72.533,622	74,086,666
Total interest charges	77,609,407	79,253,402
NET INCOME	553,489	2,184,266
RETAINED EARNINGS—Beginning of year	6,478,234	5.293,968
CASH DIVIDENDS ON COMMON STOCK	-	(1,000,000)
RETAINED EARNINGS—End of year	$ 7,031,723	$ 6,478,234

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS FOR THE YEARS ENDED DECEMBER 31, 2014 AND 2013

	2014	2013
OPERATING ACTIVITIES:		
Net income	$ 553,489	$ 2,184,266
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	65,179,764	80,172,750
Amortization of debt expense	5,075,785	5,166,736
Deferred taxes refundable taxes	3,328,233	890,065
(Gain) on marketable securities	(5,202,492)	4,331,444
Changes in assets and liabilities:		
Accounts receivable	(4,669,307)	1,620,172
Fuel in storage	(1,315,035)	36,529,701
Materials and supplies	(1,935,278)	(5,100,017)
Property taxes applicable to future years	(77,095)	(199,465)
Emission allowances	62,428	24,221
Income taxes receivable	-	12,501,130
Prepaid expenses and other	35,800	(76,270)
Other regulatory assets	(22,920,343)	46,467,540
Other noncurrent assets	367,530	(385,300)
Accounts payable	6,483,713	(829,201)
Accrued taxes	347,328	411,706
Accrued interest and other	(4,530,912)	2,322,890
Other liabilities	33,845,581	(59,752,402)
Other regulatory liabilities	(22,564,912)	28,162,184
Net cash provided by operating activities	52,064,277	154,442,150
INVESTING ACTIVITIES:		
Electric plant additions	(24,015,385)	(87,262,647)
Proceeds from sale of LT investments	18,435,960	97,023,136
Purchases of long-term investments	(18,629,572)	(40,170,784)
Net cash used in investing activities	(24,208,997)	(30,410,295)
FINANCING ACTIVITIES:		
Loan origination cost	(3,909,981)	(4,059,559)
Repayment of Senior 2006 Notes	(16,525,607)	(15,602,389)
Repayment of Senior 2007 Notes	(11,680,666)	(11,017,149)
Repayment of Senior 2008 Notes	(12,290,107)	(11,519,366)
Proceeds from line of credit	40,000,000	10,000,000
Payments on line of credit	(50,000,000)	(40,000,000)
Principal payments under capital leases	(752,663)	-
Dividends on common stock	-	(1,000,000)
Net cash provided by financing activities	(55,159,024)	(73,198,463)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(27,303,744)	50,833,392
CASH AND CASH EQUIVALENTS—Beginning of year	70,757,710	19,924,318
CASH AND CASH EQUIVALENTS—End of year	$ 43,453,966	$ 70,757,710
SUPPLEMENTAL DISCLOSURES:		
Interest paid	$ 74,387,920	$ 74,902,175
Income taxes paid (received)—net	$ 1,905,645	$ (12,501,572)
Noncash electric plant additions included in accounts payable at December 31	$ 3,187,502	$ 5,697,686

See notes to consolidated financial statements.

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Consolidated Financial Statements — The consolidated financial statements include the accounts of Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies. All intercompany transactions have been eliminated in consolidation.

Organization — The Companies own two generating stations located in Ohio and Indiana with a combined electric production capability of approximately 2,256 megawatts. OVEC is owned by several investor-owned utilities or utility holding companies and two affiliates of generation and transmission rural electric cooperatives. These entities or their affiliates comprise the Sponsoring Companies. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement (ICPA), which has a current termination date of June 30, 2040. Approximately 26% of the Companies' employees are covered by a collective bargaining agreement that expires August 31, 2017.

Prior to 2004, OVEC's primary commercial customer was the U.S. Department of Energy (DOE). The contract to provide OVEC-generated power to the DOE was terminated in 2003 and all obligations were settled at that time. Currently, OVEC has an agreement to arrange for the purchase of power (Arranged Power), under the direction of the DOE, for resale directly to the DOE. All purchase costs are billable by OVEC to the DOE.

Rate Regulation—The proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, as well as earn a return on equity before federal income taxes. In addition, the proceeds from power sales are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA. However, during 2014, the Companies began reducing their billings under the ICPA in order to effectively forego recovery of the equity return and to pass only incurred costs on to customers through the ICPA billings.

The accounting guidance for Regulated Operations provides that rate-regulated utilities account for and report assets and liabilities consistent with the economic effect of the way in which rates are established, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. The Companies follow the accounting and reporting requirements in accordance with the guidance for Regulated Operations. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the accompanying consolidated balance sheets and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers.

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through Sponsor billings at December 31, 2014 and 2013, were as follows:

	2014	2013
Regulatory assets:		
Current assets:		
Lease termination costs/liquidated damages	S -	$ 371,297
Unrecognized loss on coal sales	-	-
Total	-	371,297
Other assets:		
Unrecognized postemployment benefits	1,437,151	2,078,864
Pension benefits	32,475,646	8,542,293
Postretirement benefits	1,036,268	-
Total	34,949,065	10,621,157
Total regulatory assets	S 34,949,065	$ 10,992,454
Regulatory liabilities:		
Current liabilities:		
Deferred credit—EPA emission allowance proceeds	S 226,507	$ 275,108
Deferred revenue—voluntary severance	-	1,510,609
Deferred revenue—advances for construction	11,374,950	23,158,632
Other deferred revenue	351,534	-
Deferred credit—gain on coal sale	-	246,701
Deferred credit—advance collection of interest	2,112,403	2,215,158
Total	14,065,394	27,406,208
Other liabilities:		
Post retirement benefits	33,650,545	32,619,457
Decommissioning and demolition	14,102,619	19,140,730
Investment tax credits	-	3,393,146
Net antitrust settlement	-	1,823,929
Income taxes refundable to customers	-	28,380,282
Total	47,753,164	85,357,544
Total regulatory liabilities	S 61,818,558	$ 112,763,752

Regulatory Assets — Regulatory assets consist primarily of pension benefit costs, postemployment benefit costs and income taxes billable to customers. The Companies' current billing policy for pension and postemployment benefit costs is to bill their actual plan funding. Income taxes billable to customers are primarily billed to customers in the period when the related deferred tax liabilities are realized. The fuel related costs, including railcar lease termination costs and liquidated damages, were billed to customers in 2014.

Regulatory Liabilities—The regulatory liabilities classified as current in the accompanying consolidated balance sheet as of December 31, 2014, consist primarily of interest expense collected from customers in advance of expense recognition and customer billings for construction in progress. These amounts will be credited to customer bills during 2015. In October 2013, OVEC announced a voluntary severance program for active employees who would be retirement-eligible by the end of 2014. Approved employees in the program were entitled to receive a one-time severance payment and retired on agreed-upon dates no later than January 1, 2015. Total costs related to the payments were approximately $4.6 million for OVEC and approximately $1.6 million for IKEC, of which $3.5 million for OVEC and $1.2 million for IKEC were expensed in 2013 recorded in the Other Operation under Operating Expenses. As the Companies had collected the entire expected costs from Sponsor Companies as of December 31, 2013, the remaining $1.1 million for OVEC and $0.4 million for IKEC were recorded as a regulatory liability at December 31, 2013 and expensed during 2014. Other regulatory liabilities consist primarily of income taxes refundable to customers, postretirement benefits, and decommissioning and demolition costs. Income taxes refundable to customers are credited to customer bills in the period when any related deferred tax assets are realized.

In 2003, the DOE terminated the DOE Power Agreement with OVEC, entitling the Sponsoring Companies to 100% of OVEC's generating capacity under the terms of the ICPA. Under the terms of the DOE Power Agreement, OVEC was entitled to receive a "termination payment" from the DOE to recover unbilled costs upon termination of the agreement. The termination payment included unbilled postretirement benefit costs. In 2003, OVEC recorded a settlement payment of $97 million for the DOE obligation related to postretirement benefit costs. The regulatory liability for postretirement benefits recorded at December 31, 2014 and December 31, 2013, represents amounts collected in historical billings in excess of the Generally Accepted Accounting Principles (GAAP) net periodic benefit costs, including the DOE termination payment and incremental unfunded plan obligations recognized in the balance sheets but not yet recognizable in GAAP net periodic benefit costs. The Companies' ratemaking policy will recover postretirement benefits in an amount equal to estimated benefit accrual cost plus amortization of unfunded liabilities, if any. As a result, related regulatory liabilities are being credited to customer bills on a long-term basis.

Cash and Cash Equivalents—Cash and cash equivalents primarily consist of cash and money market funds and their carrying value approximates fair value. For purposes of these statements, the Companies consider temporary cash investments to be cash equivalents since they are readily convertible into cash and have original maturities of less than three months.

Electric Plant—Property additions and replacements are charged to utility plant accounts. Depreciation expense is recorded at the time property additions and replacements are billed to customers or at the date the property is placed in service if the in-service date occurs subsequent to the customer billing. Customer billings for construction in progress are recorded as deferred revenue-advances for construction. These amounts are closed to revenue at the time the related property is placed in service. Depreciation expense and accumulated depreciation are recorded when financed property additions and replacements are recovered over a period of years through customer debt retirement billing. All depreciable property will be fully billed and depreciated prior to the expiration of the ICPA. Repairs of property are charged to maintenance expense.

Fuel in Storage, Emission Allowances, and Materials and Supplies—The Companies maintain coal, reagent, and oil inventories for use in the generation of electricity and emission allowance inventories for regulatory compliance purposes due to the generation of electricity. These inventories are valued at average cost, less reserves for obsolescence. Materials and supplies consist primarily of replacement parts necessary to maintain the generating facilities and are valued at average cost.

Long-Term Investments—Long-term investments consist of marketable securities that are held for the purpose of funding postretirement benefits and decommissioning and demolition costs. These securities have been classified as trading securities in accordance with the provisions of the accounting guidance for Investments—Debt and Equity Securities. Trading securities reflected in Long-Term Investments are carried at fair value with the unrealized gain or loss, reported in Other Income (Expense). The cost of securities sold is based on the specific identification cost method. The fair value of most investment securities is determined by reference to currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value. See Fair Value Measurements in Note 10. Due to tax limitations, the amounts held in the postretirement benefits portfolio have not yet been transferred to the Voluntary Employee Beneficiary Association (VEBA) trusts (see Note 8). Long-term investments primarily consist of municipal bonds, money market mutual fund investments, and mutual funds. Net unrealized gains (losses) recognized during 2014 and 2013 on securities still held at the balance sheet date were $5,093,925 and $(3,698,604), respectively.

Fair Value Measurements of Assets and Liabilities—The accounting guidance for Fair Value Measurements and Disclosures establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Where observable inputs are available, pricing may be completed using comparable securities, dealer values, and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, and other observable inputs for the asset or liability.

Unamortized Debt Expense—Unamortized debt expense relates to loan origination costs incurred to secure financing. These costs are being amortized using the effective yield method over the life of the related loans.

Asset Retirement Obligations and Asset Retirement Costs—The Companies recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in depreciable electric plant. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant) and for accretion of the liability due to the passage of time.

These asset retirement obligations are primarily related to obligations associated with future asbestos abatement at certain generating stations and certain plant closure costs.

Balance—January 1, 2013	$20,961,379
Accretion	1,450,943
Liabilities settled	(182,213)
Balance—December 31, 2013	22,230,109
Accretion	1,466,117
Liabilities settled	(35,122)
Revision to cash flows	5,886,081
Balance—December 31, 2014	$29,547,185

During 2014 the Companies completed an updated study to estimate the asset retirement costs described above. The revised estimated costs are recorded in the accompanying balance sheets.

The Companies do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. The Companies have asset retirement obligations associated with transmission assets at certain generating stations. However, the retirement date for these assets cannot be determined: therefore, the fair value of the associated liability currently cannot be estimated and no amounts are recognized in the consolidated financial statements herein.

Income Taxes—The Companies use the liability method of accounting for income taxes. Under the liability method, the Companies provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. The Companies account for uncertain tax positions in accordance with the accounting guidance for Income Taxes.

Use of Estimates—The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

New Accounting Pronouncements—In May 2014, the FASB issued an accounting standards update which amends the guidance for revenue recognition. This amendment contains principals that will require an entity to recognize revenue to depict the transfer of goods and services to customers at an amount that an entity expects to be entitled to in exchange for goods or services. The amendment sets forth a new revenue recognition model that requires identifying the contract, identifying the performance obligations and recognizing the revenue upon satisfaction of performance obligations. This amendment is effective for the Companies beginning January 1, 2017. At this time, the Companies have not determined the impact of this amendment to the Companies' financial statements.

In August 2014, the FASB issued guidance that requires management to evaluate whether there are conditions or events that raise substantial doubt about the entity's ability to continue as a going concern within one year from the date the financial statements are issued. The new guidance is effective for reporting periods beginning after December 15, 2016. The new guidance is effective for the Companies beginning January 1, 2017. The Companies are currently evaluating the impact that the new accounting standard will have on the financial statements.

Subsequent Events—In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 16, 2015, which is the date the consolidated financial statements were issued.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2014 and 2013 included the sale of all generated power to them, the purchase of Arranged Power from them and other utility systems in order to meet the Department of Energy's power requirements, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, Kentucky Utilities Company, Ohio Edison Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies; and Transmission Service Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, The Toledo Edison Company, Ohio Edison Company, Kentucky Utilities Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies.

At December 31, 2014 and 2013, balances due from the Sponsoring Companies are as follows:

	2014	2013
Accounts receivable	$34,842,796	$31,129,486

During 2014 and 2013, American Electric Power accounted for approximately 43% of operating revenues from Sponsoring Companies and Buckeye Power accounted for 18%. No other Sponsoring Company accounted for more than 10%.

American Electric Power Company, Inc. and subsidiary company owned 43.47% of the common stock of OVEC as of December 31, 2014. The following is a summary of the principal services received from the American Electric Power Service Corporation as authorized by the Companies' Boards of Directors:

	2014	2013
General services	$ 3,009,076	$ 3,384,509
Specific projects	2,732,041	10,964,133
Total	$ 5,741,117	$14,348,642

General services consist of regular recurring operation and maintenance services. Specific projects primarily represent nonrecurring plant construction projects and engineering studies, which are approved by the Companies' Boards of Directors. The services are provided in accordance with the service agreement dated December 15, 1956, between the Companies and the American Electric Power Service Corporation.

3. COAL SUPPLY

The Companies have coal supply agreements with certain nonaffiliated companies that expire at various dates from the year 2015 through 2017. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have approximately 100% of their 2015 coal requirements under contract. These contracts are based on rates in effect at the time of purchase.

4. ELECTRIC PLANT

Electric plant at December 31, 2014 and 2013, consists of the following:

	2014	2013
Steam production plant	$ 2,615,435,925	$ 2,582,429,102
Transmission plant	77,990,925	76,855,762
General plant	12,932,238	12,495,791
Intangible	26,564	26,564
	2,706,385,652	2,671,807,219
Less accumulated depreciation	1,245,490,373	1,182,491,224
	1,460,895,279	1,489,315,995
Construction in progress	15,329,947	30,583,795
Total electric plant	$ 1,476,225,226	$ 1,519,899,790

All property additions and replacements are fully depreciated on the date the property is placed in service, unless the addition or replacement relates to a financed project. As the Companies' policy is to bill in accordance with the principal billings of the debt agreements, all financed projects are being depreciated in amounts equal to the principal payments on outstanding debt.

5. BORROWING ARRANGEMENTS AND NOTES

OVEC has an unsecured bank revolving line of credit agreement with a borrowing limit of $200 million as of December 31, 2014 and $275 million as of December 31, 2013. The $200 million line of credit has an expiration date of November 17, 2019. At December 31, 2014 and 2013, OVEC had borrowed $20 million and $30 million, respectively, under this line of credit. Interest expense related to line of credit borrowings was $212,497 in 2014 and $634,109 in 2013. During 2014 and 2013, OVEC incurred annual commitment fees of $782,455 and $737,792, respectively, based on the borrowing limits of the line of credit.

6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2014 and 2013:

	Interest Rate	2014	2013
Senior 2006 Notes:			
2006A due February 15, 2026	5.80 %	$ 261,689.554	$ 277,326,804
2006B due June 15, 2040	6.40	59,530.005	60.418,362
Senior 2007 Notes:			
2007A-A due February 15, 2026	5.90	118,269.553	125,578,853
2007A-B due February 15, 2026	5.90	30,022.192	31.625,801
2007A-C due February 15, 2026	5.90	29,785,026	31,877,625
2007B-A due June 15, 2040	6.50	29,740.287	30.188,693
2007B-B due June 15. 2040	6.50	7,489.798	7,602.725
2007B-C due June 15. 2040	6.50	7,549.435	7,663,261
Senior 2008 Notes:			
2008A due February 15, 2026	5.92	36,907.905	39.185,975
2008B due February 15, 2026	6.71	74,433,137	78,865,206
2008C due February 15, 2026	6.71	76,117.755	80,487,688
2008D due June 15, 2040	6.91	43,081.900	43.681,707
2008E due June 15. 2040	6.91	43,830.471	44,440,700
Series 2009 Bonds:			
2009A due February 1, 2026	0.60	25,000.000	25.000,000
2009B due February 1, 2026	0.48	25,000,000	25.000,000
2009C due February 1, 2026	0.60	25,000,000	25,000,000
2009D due February 1, 2026	0.48	25,000.000	25.000,000
2009E due October 1, 2019	5.63	100,000,000	100,000,000
Series 2010 Bonds:			
2010A due June 29, 2017	1.44	50,000.000	50.000,000
2010B due June 29, 2016	1.44	50,000,000	50,000,000
Series 2012 Bonds:			
2012A due June 1, 2032	5.00	76,800.000	77,080,192
2012A due June 1, 2039	5.00	123,200,000	122,346,343
2012B due June 1, 2040	0.72	50,000,000	50,000,000
2012C due June 1, 2040	0.36	50,000.000	50.000,000
Series 2013 Notes:			
2013A due February 15, 2018	1.66	100,000,000	100.000.000
Total debt		1,518,447.018	1,558,369,935
Total premiums and discounts (net)		(550,863)	-
Total debt net of premiums and discounts		1,517,896,155	1,558,369,935
Current portion of long-term debt		243,000,194	290,496,381
Total long-term debt		$ 1,274,895,961	$ 1,267,873,554

All of the OVEC amortizing unsecured senior notes have maturities scheduled for February 15, 2026, or June 15, 2040, as noted in the previous table.

During 2009, OVEC issued $100 million variable rate non-amortizing unsecured senior notes (2009A Notes) in private placement, a series of four $25 million variable rate non-amortizing tax exempt pollution control bonds (2009A, B, C, and D Bonds), and $100 million fixed rate non-amortizing tax exempt pollution control bonds (2009E Bonds). The variable rates listed above reflect the interest rate in effect at December 31, 2014.

The 2009 Series A, B, C, and D Bonds are secured by irrevocable transferable direct-pay letters of credit, expiring August 12, 2016, and August 21, 2016, issued for the benefit of the owners of the bonds. The interest rate on the bonds are adjusted weekly, and bondholders may require repurchase of the bonds at the time of such interest rate adjustments. OVEC has entered into an agreement to provide for the remarketing of the bonds if such repurchase is required. The 2009A, B, C, and D Series Bonds are current, as they are redeemable at the election of the holders at any time.

In December 2010, OVEC established a borrowing facility under which OVEC borrowed, in 2011, $100 million variable rate bonds due February 1, 2040. In June 2011, the $100 million variable rate bonds were issued as two $50 million non-amortizing pollution control revenue bonds (Series 2010A and 2010B) with initial interest periods of three years and five years, respectively. The Series 2010A bond was extended for another three years in June 2014 to June 29, 2017.

During 2012, OVEC issued $200 million fixed rate tax-exempt midwestern disaster relief revenue bonds (2012A Bonds) and two series of $50 million variable rate tax-exempt midwestern disaster relief revenue bonds (2012B and 2012C Bonds). The 2012A, 2012B, and 2012C Bonds will begin amortizing June 1, 2027, to their respective maturity dates. The variable rates listed above reflect the interest rate in effect at December 31, 2014.

The 2012B and 2012C Bonds are secured by irrevocable transferable direct-pay letters of credit, expiring June 28, 2017, and June 28, 2015, issued for the benefit of the owners of the bonds. The interest rates on the bonds are adjusted weekly, and bondholders may require repurchase of the bonds at the time of such interest rate adjustments. OVEC has entered into agreements to provide for the remarketing of the bonds if such repurchase is required. The 2012B and 2012C Bonds are current, as they are redeemable at the election of the holders at any time.

In 2013, the $100 million 2009A Notes were retired on February 15, 2013, with funding from the issuance of $100 million 2013A variable rate non-amortizing unsecured senior notes (2013A Notes). The 2013A Notes mature on February 15, 2018.

The annual maturities of long-term debt as of December 31, 2014, are as follows:

2015	$ 243,000,194
2016	95,536,872
2017	48,461,307
2018	51,460,006
2019	154,647,515
2020–2040	925,341,124
Total	$1,518,447,018

Note that the 2015 current maturities of long-term debt include $200 million of remarketable variable-rate bonds. The Companies expect cash maturities of only $43,000,194 to the extent the remarketing agents are successful in their ongoing efforts to remarket the bonds through the contractual maturity dates in February 2026 and June 2040.

7. INCOME TAXES

OVEC and IKEC file a consolidated federal income tax return. The effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

	2014	2013
Income tax expense at 35% statutory rate	$ 309,862	$ 1,076,125
State income taxes—net of federal benefit	203,769	-
Temporary differences flowed through to customer bills	(200,141)	(212,144)
Permanent differences and other	18,344	26,396
Income tax provision	$ 331,834	$ 890,377

Components of the income tax provision were as follows:

	2014	2013
Current income tax (benefit)/expense	$313,490	$ -
Deferred income tax expense/(benefit)	18,344	890,377
Total income tax provision	$331,834	$890,377

OVEC and IKEC record deferred tax assets and liabilities based on differences between book and tax basis of assets and liabilities measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Deferred tax assets and liabilities are adjusted for changes in tax rates.

To the extent that the Companies have not reflected credits in customer billings for deferred tax assets, they have recorded a regulatory liability representing income taxes refundable to customers under the applicable agreements among the parties. The regulatory liability was $0 and $28,380,282 at December 31, 2014 and 2013, respectively.

Deferred income tax assets (liabilities) at December 31, 2014 and 2013, consisted of the following:

	2014	2013
Deferred tax assets:		
Deferred revenue—advances for construction	$ 4,108,103	$ 8,110,780
AMT credit carryforwards	12,030,465	2,574,572
Federal net operating loss carryforwards	68,603,277	61,312,280
Postretirement benefit obligation	15,721,185	14,770,267
Pension liability	9,835,656	1,684,610
Postemployment benefit obligation	503,473	728,074
Asset retirement obligations	10,351,175	7,785,586
Miscellaneous accruals	2,705,995	2,131,262
Regulatory liability—other	30,927	1,288,943
Regulatory liability—investment tax credits	-	1,188,372
Regulatory liability—net antitrust settlement	-	638,789
Regulatory liability—asset retirement costs	4,951,051	6,703,602
Regulatory liability—postretirement benefits	10,587,096	10,283,147
Regulatory liability—income taxes refundable to customers	15,575,898	13,856,458
Total deferred tax assets	155,004,301	133,056,742
Deferred tax liabilities:		
Prepaid expenses	(660,931)	(679,165)
Electric plant	(92,761,349)	(85,468,227)
Unrealized gain/loss on marketable securities	(5,281,413)	(3,580,925)
Regulatory asset—postretirement benefits	-	-
Regulatory asset—pension benefits	(11,377,094)	(2,991,742)
Regulatory asset—unrecognized postemployment benefits	(503,473)	(728,074)
Total deferred tax liabilities	(110,584,260)	(93,448,133)
Valuation allowance	(44,420,041)	(10,195,362)
Deferred income tax assets	$ -	$ 29,413,247
Current deferred income taxes	$ 4,237,801	$ 9,980,768
Noncurrent deferred income taxes	(4,237,801)	19,432,479

As discussed in Note 1, OVEC indefinitely changed its billing practices in 2014 to effectively suspend billings for its authorized equity return. As a result, the Companies' long-term expectation is that taxable income will be breakeven for the foreseeable future. Accordingly, the Companies have recorded a valuation allowance as of December 31, 2014.

The accounting guidance for Income Taxes addresses the determination of whether the tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Companies may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The Companies have not identified any uncertain tax positions as of December 31, 2014 and 2013, and accordingly, no liabilities for uncertain tax positions have been recognized.

The Companies file income tax returns with the Internal Revenue Service and the states of Ohio. Indiana. and the Commonwealth of Kentucky. The Companies are no longer subject to federal tax examinations for tax years 2010 and earlier. The Companies completed an audit by the Internal Revenue Service for the tax years ended December 31, 2008 through December 31, 2012. The Companies are no longer subject to State of Indiana tax examinations for tax years 2010 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2009 and earlier.

8. PENSION PLAN, OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

The Companies have a noncontributory qualified defined benefit pension plan (the Pension Plan) covering substantially all of their employees. The benefits are based on years of service and each employee's highest consecutive 36-month compensation period. Employees are vested in the Pension Plan after five years of service with the Companies.

Funding for the Pension Plan is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974 (ERISA), as amended.

In addition to the Pension Plan, the Companies provide certain health care and life insurance benefits (Other Postretirement Benefits) for retired employees. Substantially all of the Companies' employees become eligible for these benefits if they reach retirement age while working for the Companies. These and similar benefits for active employees are provided through employer funding and insurance policies. In December 2004, the Companies established Voluntary Employee Beneficiary Association (VEBA) trusts. In January 2011, the Companies established an IRC Section 401(h) account under the Pension Plan.

The full cost of the pension benefits and other postretirement benefits has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 56% and 44% split between OVEC and IKEC, respectively, as of December 31, 2014, and approximately a 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2013.

The Pension Plan's assets as of December 31, 2014. consist of investments in equity and debt securities.

All of the trust funds' investments for the pension and postemployment benefit plans are diversified and managed in compliance with all laws and regulations. Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation when appropriate. The investments are reported at fair value under the Fair Value Measurements and Disclosures accounting guidance.

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies, and target asset allocations by plan. Benefit plan assets are reviewed on a formal basis each quarter by the OVEC/IKEC Qualified Plan Trust Committee.

The investment philosophies for the benefit plans support the allocation of assets to minimize risks and optimize net returns.

Investment strategies include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs, and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style neutral to limit volatility compared to applicable benchmarks.

The target asset allocation for each portfolio is as follows:

Pension Plan Assets	Target
Domestic equity	15.0 %
International and global equity	15.0
Fixed income	70.0

VEBA Plan Assets	Target
Domestic equity	20.0 %
International and global equity	20.0
Fixed income	57.0
Cash	3.0

Each benefit plan contains various investment limitations. These limitations are described in the investment policy statement and detailed in customized investment guidelines. These investment guidelines require appropriate portfolio diversification and define security concentration limits. Each investment manager's portfolio is compared to an appropriate diversified benchmark index.

Equity investment limitations:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of each investment manager's equity portfolio.
- Individual securities must be less than 15% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

Fixed Income Limitations—As of December 31, 2014, the Pension Plan fixed income allocation consists of managed accounts composed of U.S. Government, corporate, and municipal obligations. The VEBA benefit plans' fixed income allocation is composed of a variety of fixed income securities and mutual funds. Investment limitations for these fixed income funds are defined by manager prospectus.

Cash Limitations—Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments, including money market mutual funds, certificates of deposit, treasury bills, and other types of investment-grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Projected Pension Plan and Other Postretirement Benefits obligations and funded status as of December 31, 2014 and 2013, are as follows:

	Pension Plan		Other Postretirement Benefits	
	2014	2013	2014	2013
Change in projected benefit obligation:				
Projected benefit obligation—beginning of year	$ 179,046,962	$ 195,007,159	$ 162,744,143	$ 190,323,891
Service cost	5,652,257	6,825,230	5,887,965	7,375,556
Interest cost	9,156,641	8,357,208	8,358,022	8,180,654
Plan participants' contributions	-	-	1,108,208	979,846
Benefits paid	(8,355,638)	(4,289,481)	(4,938,909)	(5,067,595)
Net actuarial (gain)/loss	40,681,544	(23,604,558)	21,209,006	(39,654,091)
Medicare subsidy	-	-	150,041	300,508
Plan amendments	(3,274,589)	(3,173,345)	(22,744,039)	305,374
Expenses paid from assets	(83,288)	(75,251)	-	-
Projected benefit obligation—end of year	222,823,889	179,046,962	171,774,437	162,744,143
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	170,504,669	164,445,834	120,570,742	108,226,268
Actual return on plan assets	21,682,500	4,000,880	5,275,212	9,279,474
Expenses paid from assets	(83,288)	(75,251)	-	-
Employer contributions	6,600,000	6,422,687	4,733,391	6,852,241
Plan participants' contributions	-	-	1,108,208	979,846
Medicare subsidy	-	-	150,041	300,508
Benefits paid	(8,355,638)	(4,289,481)	(4,938,909)	(5,067,595)
Fair value of plan assets—end of year	190,348,243	170,504,669	126,898,685	120,570,742
(Underfunded) status—end of year	$ (32,475,646)	$ (8,542,293)	$ (44,875,752)	$ (42,173,401)

See Note 1 for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits plan. During 2014, the Companies amended their Other Postretirement Benefits plan to require additional employee cost sharing for certain groups of employees resulting in a $22.7 million reduction in PBO for 2014, as detailed in the above table.

On December 8, 2003, the President of the United States of America signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act introduced a prescription drug benefit to retirees as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is actuarially equivalent to the benefit provided by Medicare. The Companies believe that the coverage for prescription drugs is at least actuarially equivalent to the benefits provided by Medicare for most current retirees because the benefits for that group substantially exceed the benefits provided by Medicare, thereby allowing the Companies to qualify for the subsidy. The Companies' employer contributions for Other Postretirement Benefits in the previous table are net of subsidies received of $150,041 and $300,508 for 2014 and 2013, respectively. The Companies have accounted for the subsidy as a reduction of the benefit obligation detailed in the previous table. In June 2013, the Companies converted the prescription drug program for retirees over the age of 65 to a group-based company sponsored Medicare Part D program, or Employer Group Waiver Plan (EGWP). Beginning in June 2013, the Companies use the Part D subsidies delivered through the EGWP each year to reduce net company retiree medical costs. Accordingly, the Companies no longer receive subsidies directly from the Medicare program and no subsidies have been included in the benefit obligation.

The accumulated benefit obligation for the Pension Plan was $195,776,660 and $156,748,676 at December 31, 2014 and 2013, respectively.

Components of Net Periodic Benefit Cost—The Companies record the expected cost of Other Postretirement Benefits over the service period during which such benefits are earned.

Pension expense is recognized as amounts are contributed to the Pension Plan and billed to customers. The accumulated difference between recorded pension expense and the yearly net periodic pension expense, as calculated under the accounting guidance for Compensation—Retirement Benefits, is billable as a cost of operations under the ICPA when contributed to the pension fund. This accumulated difference has been recorded as a regulatory asset in the accompanying consolidated balance sheets.

	Pension Plan		Other Postretirement Benefits	
	2014	2013	2014	2013
Service cost	$ 5,652,257	$ 6,825,230	$ 5,887,965	$ 7,375,556
Interest cost	9,156,641	8,357,208	8,358,022	8,180,654
Expected return on plan assets	(10,233,418)	(9,088,934)	(6,482,601)	(5,562,089)
Amortization of prior service cost	(180,575)	189,437	24,041	(385,000)
Recognized actuarial loss	-	428,567	(234,171)	1,828,893
Total benefit cost	$ 4,394,905	$ 6,711,508	$ 7,553,256	$ 11,438,014
Pension and other postretirement benefits expense recognized in the consolidating statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 6,600,000	$ 6,422,687	$ -	$ 5,400,000

The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2014 and 2013:

	Fair Value Measurements at Reporting Date Using		
2014	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Domestic equity mutual funds	$ 14,850,107	$ -	$ -
Common stock—domestic	7,600,351	-	-
International and global equity mutual funds	20,792,451	-	-
International and global private investment funds (equities)	-	11,078,646	-
Cash equivalents	4,451,721	-	-
U.S. Treasury securities	-	6,264,602	-
Corporate debt securities	-	116,102,015	-
Municipal debt securities	-	9,208,350	-
Total fair value	$ 47,694,630	$ 142,653,613	$ -
2013			
Domestic equity mutual funds	$ 16,572,985	$ -	$ -
Common stock—domestic	8,480,137	-	-
International and global equity mutual funds	24,557,818	-	-
International and global private investment funds (equities)	-	5,102,504	-
Cash equivalents	5,211,961	-	-
U.S. Treasury securities	-	7,505,362	-
Corporate debt securities	-	94,537,258	-
Municipal debt securities	-	8,536,644	-
Total fair value	$ 54,822,901	$ 115,681,768	$ -

The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2014 and 2013:

	Fair Value Measurements at Reporting Date Using		
2014	*Quoted Prices in Active Market for Identical Assets* (Level 1)	*Significant* Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic equity mutual funds	$ 41,122,698	$ -	$ -
International and global equity mutual funds	20,812,612	-	-
International and global private investment funds	-	6,731,149	-
Fixed income mutual funds	38,452,331	-	-
Fixed income securities	-	17,426,355	-
Cash equivalents	2,353,540	-	-
Total fair value	$ 102,741,181	$ 24,157,504	$ -
2013			
Domestic equity mutual funds	$ 40,105,729	$ -	$ -
International and global equity mutual funds	22,737,909	-	-
International and global private investment funds	-	4,267,427	-
Fixed income mutual funds	33,485,886	-	-
Fixed income securities	-	13,940,290	-
Cash equivalents	6,033,501	-	-
Total fair value	$ 102,363,025	$ 18,207,717	$ -

The private investment fund detailed in the above tables is redeemable at the election of the holder upon no more than 30 days' notice and, as such, this fund has been classified as a Level 2 fair value measure.

Pension Plan and Other Postretirement Benefit Assumptions—Actuarial assumptions used to determine benefit obligations at December 31, 2014 and 2013, were as follows:

	Pension Plan		Other Postretirement Benefits			
	2014	2013	2014		2013	
			Medical	Life	Medical	Life
Discount rate	4.28 %	5.15 %	4.33 %	4.33 %	5.20 %	5.20 %
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2014 and 2013, were as follows:

	Pension Plan		Other Postretirement Benefits			
	2014	2013	2014		2013	
			Medical	Life	Medical	Life
Discount rate	5.15 %	4.29 %	5.20 %	5.20 %	4.40 %	4.30 %
Expected long-term return on plan assets	6.00	5.50	5.29	6.00	4.95	5.75
Rate of compensation increase	3.00	3.00	N A	3.00	N/A	3.00

In selecting the expected long-term rate of return on assets, the Companies considered the average rate of earnings expected on the funds invested to provide for plan benefits. This included considering the Pension Plan and VEBA trusts' asset allocation, and the expected returns likely to be earned over the life of the Pension Plan and the VEBAs.

Assumed health care cost trend rates at December 31, 2014 and 2013, were as follows:

	2014	2013
Health care trend rate assumed for next year—participants under 65	7.00 %	7.50 %
Health care trend rate assumed for next year—participants over 65	7.00	7.50
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants under 65	5.00	5.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants over 65	5.00	5.00
Year that the rate reaches the ultimate trend rate	2019	2019

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One-Percentage Point Increase	One-Percentage Point Decrease
Effect on total service and interest cost	$ 3,156,652	$ (2,398,815)
Effect on postretirement benefit obligation	31,503,493	(24,403,704)

Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2014 and 2013, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2014	2013	2014	2013
Asset category:				
Equity securities	29 %	32 %	39 %	42 %
Debt securities	71	68	61	58

Pension Plan and Other Postretirement Benefit Contributions—The Companies expect to contribute $5,600,000 to their Pension Plan and $5,355,051 to their Other Postretirement Benefits plan in 2015.

Estimated Future Benefit Payments—The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years Ending December 31	Pension Plan	Other Postretirement Benefits
2015	$ 6,384,692	$ 5,894,867
2016	7,153,692	6,323,071
2017	8,182,919	6,758,905
2018	8,789,634	7,198,179
2019	9,799,896	7,720,128
Five years thereafter	62,127,081	46,175,651

Postemployment Benefits—The Companies follow the accounting guidance in Compensation—Non-Retirement Postemployment Benefits and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 27% and 73% split between OVEC and IKEC, respectively, as of December 31, 2014, and approximately a 56% and 44% split between OVEC and IKEC, respectively, as of December 31, 2013. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was $1,437,151 and $2,078,864 at December 31, 2014 and 2013, respectively.

Defined Contribution Plan—The Companies have a trustee-defined contribution supplemental pension and savings plan that includes 401(k) features and is available to employees who have met eligibility requirements. The Companies' contributions to the savings plan equal 100% of the first 1% and 50% of the next 5% of employee-participants' contributions. Benefits to participating employees are based solely upon amounts contributed to the participants' accounts and investment earnings. By its nature, the plan is fully funded at all times. The employer contributions for 2014 and 2013 were $1,939,829 and $1,956,546, respectively.

9. ENVIRONMENTAL MATTERS

Title IV of the 1990 Clean Air Act Amendments (CAAAs) required the Companies to reduce sulfur dioxide ($SO2$) emissions in two phases: Phase I in 1995 and Phase II in 2000. The Companies selected a fuel switching strategy to comply with the emission reduction requirements. The Companies also purchased additional $SO2$ allowances. Historically, the cost of these purchased allowances has been inventoried and included on an average cost basis in the cost of fuel consumed when used.

Title IV of the 1990 CAAAs also required the Companies to comply with a nitrogen oxides (NOx) emission rate limit of 0.84 lb/mmBtu in 2000. The Companies installed overfire air systems on all eleven units at the plants to comply with this limit. The total capital cost of the eleven overfire air systems was approximately $8.2 million.

During 2002 and 2003, Ohio and Indiana finalized respective NOx State Implementation Plan (SIP) Call regulations that required further significant NOx emission reductions for coal-burning power plants during the ozone control period. The Companies installed selective catalytic reduction (SCR) systems on ten of their eleven units to comply with these rules. The total capital cost of the ten SCR systems was approximately $355 million.

On March 10, 2005, the United States Environmental Protection Agency (the U.S. EPA) issued the Clean Air Interstate Rule (CAIR) that required further significant reductions of SO2 and NOx emissions from coal-burning power plants. On March 15, 2005, the U.S. EPA also issued the Clean Air Mercury Rule (CAMR) that required significant mercury emission reductions for coal-burning power plants. These emission reductions were required in two phases: 2009 and 2015 for NOx; 2010 and 2015 for SO2; and 2010 and 2018 for mercury. Ohio and Indiana subsequently finalized their respective versions of CAIR and CAMR. In response, the Companies determined that it would be necessary to install flue gas desulfurization (FGD) systems at both plants to comply with these new rules. Following completion of the necessary engineering and permitting, construction was started on the new FGD systems.

In February 2008, the D.C. Circuit Court of Appeals issued a decision which vacated the federal CAMR and remanded the rule to the U.S. EPA with a determination that the rule be rewritten under the maximum achievable control technologies (MACT) provision of Section 112(d) of the Clean Air Act. A group of electric utilities and the U.S. EPA requested a rehearing of the decision, which was denied by the Court. Following those denials, both the group of electric utilities and the U.S. EPA requested that the U.S. Supreme Court hear the case. However, in February 2009, the U.S. EPA withdrew its request and the group of utilities' request was denied. These actions left the original court decision in place, which vacated the federal CAMR and remanded the rule to the U.S. EPA with a determination that the rule be rewritten under the MACT provision of Section 112(d) of the Clean Air Act. The U.S. EPA has subsequently written a replacement rule for the regulation of coal-fired utility emissions of mercury and other hazardous air pollutants. This replacement rule was published in the Federal Register on February 16, 2012, and it is referred to as the Mercury and Air Toxics Standards (or MATS) rule. The rule became final on April 16, 2012, and OVEC-IKEC must be in compliance with MATS emission limits by April 16, 2015. Management expects that, with the SCRs and FGD systems fully functional, OVEC-IKEC will be able to meet the emissions requirements outlined in the MATS rule.

In July 2008, the D.C. Circuit Court of Appeals issued a decision that vacated the federal CAIR and remanded the rule to the U.S. EPA. In September 2008, the U.S. EPA, a group of electric utilities and other parties filed petitions for rehearing. In December 2008, the D.C. Circuit Court of Appeals granted the U.S. EPA's petition and remanded the rule to the U.S. EPA without vacatur, allowing the federal CAIR to remain in effect while a new rule was developed and promulgated. Following the remand, the U.S. EPA promulgated a replacement rule to CAIR. This new rule is called the Cross-State Air Pollution Rule (CSAPR) and it was issued on July 6, 2011, and it was scheduled to go into effect on January 1, 2012. However, on December 30, 2011, the D.C. Circuit Court issued an indefinite "stay" of the CSAPR rule until the Court considered the numerous state, trade association, and industry petitions filed to have the rule either stayed or reviewed. The Court also instructed the U.S. EPA to keep CAIR in place while they considered the numerous petitions. On August 21, 2012, in a 2-1 decision, the D.C. Circuit Court vacated the CSAPR rule and ordered the U.S. EPA to keep CAIR in effect until a CSAPR replacement rule is promulgated. The U.S. EPA and other parties filed a petition seeking rehearing before the entire

D.C. Circuit Court on October 5, 2012. That petition was denied by the D.C. Circuit Court on January 24, 2013; however, the U.S. Solicitor General petitioned the U.S. Supreme Court to review the D.C. Circuit Court's decision on CSAPR in March of 2013, and the Supreme Court granted that petition in June of 2013. Oral arguments were presented before the Supreme Court in December of 2013. On April 29, 2014, the U.S. Supreme Court issued a decision reversing the D.C. Circuit Court's 2013 CSAPR vacatur and remanded the CSAPR rule back to that court for further deliberation. On October 23, 2014, the D.C. Circuit Court issued a motion lifting the stay on the CSAPR rules and then U.S. EPA issued a ministerial rule on November 21, 2014 that allowed CSAPR to become effective on January 1, 2015. There are remaining issues with the CSAPR rule that are before the D.C. Circuit Court, and the court is expected to issue a ruling on them by the summer of 2015. In the interim, OVEC-IKEC expects to be able to comply with CSAPR, as currently written.

With the Kyger Creek FGD and the Clifty Creek FGD systems now fully operational, and with the 10 SCR systems operational at both plants, management did not need to purchase additional SO2 allowances in 2014; however, there was a need to purchase a limited quantity of NOx allowances in 2014. Depending on a variety of operational and economic factors, management may also elect to strategically purchase CSAPR NOx allowances in 2015 and beyond.

Now that all FGD systems are fully operational, OVEC-IKEC expects to have adequate SO2 allowances available without having to rely on market purchases to comply with the CSAPR rules in their current form; however, the purchase of additional NOx allowances or the installation of additional NOx controls may be necessary for Clifty Creek Unit 6 either under the CSAPR rule or any future NOx regulations. During the 2013 compliance period and prior to the FGD systems becoming fully operational, OVEC purchased SO2 and NOx allowances to operate the Clifty Creek generating units in compliance with the CAIR environmental emission rules.

On November 6, 2009, the Companies received a Section 114 Information Request from the U.S. EPA. The stated purpose of the information request was for the U.S. EPA to obtain the necessary information to determine if the Kyger Creek and Clifty Creek plants have been operating in compliance with the Federal Clean Air Act. Attorneys for the Companies subsequently contacted the U.S. EPA and established a schedule for submission of the requested information. Based on this schedule, all requested information was submitted to the U.S. EPA by March 8, 2010.

In late December 2011, OVEC-IKEC received a letter dated December 21, 2011, from the U.S. EPA requesting follow-up information. Specifically, the U.S. EPA asked for an update on the status of the FGD scrubber projects at both plants as well as additional information on any other new emissions controls that either have been installed or are planned for installation since the last submittal we filed on March 8, 2012. This information was prepared and filed with the U.S. EPA in late January 2012. In the fall of 2012, following an on-site visit, the U.S. EPA made an informal request that OVEC-IKEC provide the agency with a monthly email progress report on the Clifty Creek FGD project until both FGD systems are operational in 2013. As of this date, the only communication OVEC-IKEC has had with the U.S. EPA related to either the original Section 114 data submittal or the supplemental data filing made in 2011 are the monthly email progress reports. Those monthly email progress reports were discontinued once the second of the two FGD scrubbers at Clifty Creek was placed into service in May of 2013.

Coal Combustion Residual Rule

In 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. To comply with a court-ordered deadline, the Federal EPA issued a prepublication copy of its final rule in December 2014. The rule is expected to be published in the Federal Register during 2015 and become effective six months following publication.

In the final rule, the Federal EPA elected to regulate CCR as a non-hazardous solid waste and issued new minimum federal solid waste management standards. On the effective date, the rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements. The rule does not apply to inactive CCR landfills and inactive surface impoundments at retired generating stations or the beneficial use of CCR. The rule is self-implementing so state action is not required. Because of this self-implementing feature, the rule contains extensive record keeping, notice, and internet posting requirements. Because OVEC-IKEC currently uses surface impoundments and landfills to manage CCR materials at our generating facilities, OVEC-IKEC may incur costs to modify, upgrade or close, and replace these existing facilities at some point in the future as the new rule is implemented. OVEC-IKEC continue to review the new rule and evaluate its costs and impacts to our operations, including ongoing monitoring requirements.

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the Federal EPA supports these beneficial uses. Currently, approximately 5% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials, and for other beneficial uses. Encapsulated beneficial uses are not materially impacted by the new rule, but additional demonstrations may be required to continue land applications in significant amounts except in road construction projects.

10. FAIR VALUE MEASUREMENTS

The accounting guidance for Financial Instruments requires disclosure of the fair value of certain financial instruments. The estimates of fair value under this guidance require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed.

OVEC utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the benefit plan trusts and investment portfolios. The Companies' management reviews and validates the prices utilized by the trustee to determine fair value. Equities and fixed income securities are classified as Level 1 holdings if they are actively traded on exchanges. In addition, mutual funds are classified as Level 1 holdings because they are actively traded at quoted market prices. Certain fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker dealer quotes, issuer spreads, bids, offers, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

As of December 31, 2014 and 2013, the Companies held certain assets that are required to be measured at fair value on a recurring basis. These consist of investments recorded within long-term investments. The investments consist of money market mutual funds, equity mutual funds, and fixed income municipal securities. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value, and unrealized gains and losses are recorded in earnings.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Companies believe their valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

As cash and cash equivalents, current receivables, current payables, and line of credit borrowings are all short term in nature, their carrying amounts approximate fair value.

Long-Term Investments—Assets measured at fair value on a recurring basis at December 31, 2014 and 2013, were as follows:

	Fair Value Measurements at Reporting Date Using		
2014	Quoted Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Equity mutual funds	$ 25,372,238	-	-
Fixed income municipal securities	-	91,600,666	-
Cash equivalents	5,529,869	-	-
Total fair value	$ 30,902,107	$ 91,600,666	-
2013			
Equity mutual funds	$ 24,795,074	$ -	$ -
Fixed income municipal securities	-	88,696,555	-
Cash equivalents	3,615,039	-	-
Total fair value	$ 28,410,113	$ 88,696,555	$ -

Long-Term Debt — The fair values of the senior notes and fixed rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets.

The fair values and recorded values of the senior notes and fixed and variable rate bonds as of December 31, 2014 and 2013, are as follows:

	2014		2013	
	Fair Value	Recorded Value	Fair Value	Recorded Value
Total	$ 1,702,226,733	$ 1,517,896,155	$ 1,684,165,978	$ 1,558,369,935

11. LEASES

OVEC has railcar lease agreements that extend to January 1, 2016. OVEC also has various other operating leases for the use of other property and equipment. During 2013, OVEC terminated certain railcar lease agreements for the transportation of coal in conjunction with the fuel switching strategy that had been employed by the Companies' generating stations prior to the in-service date of the FGD's discussed in Note 9. This resulted in lease termination costs of $3,497,300 billed to Sponsor Companies during 2014 and 2013 of $371,297 and $3,126,003, respectively.

The amount in property under capital leases is $3,100.767 and S2,793.119 with accumulated depreciation of $1,441,030 and S905.642 as of December 31. 2014 and 2013, respectively.

Future minimum lease payments for capital and operating leases at December 31. 2014, are as follows:

Years Ending December 31	Operating	Capital
2015	$ 822.863	$ 672.589
2016	24,465	417.385
2017	2.846	321.461
2018	-	192.347
2019	-	107.722
Thereafter	-	428,410
Total future minimum lease payments	$ 850,174	2,139,914
Less estimated interest element		463,050
Estimated present value of future minimum lease payments		$ 1,676.864

The annual operating lease cost incurred was $1,079,950 and S1,862,319 for 2014 and 2013, respectively, and the annual capital lease cost incurred was S752,663 and S593,456 for 2014 and 2013, respectively.

12. COMMITMENTS AND CONTINGENCIES

The Companies are party to or may be affected by various matters under litigation. Management believes that the ultimate outcome of these matters will not have a significant adverse effect on either the Companies' future results of operation or financial position.

* * * * * *

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Ohio Valley Electric Corporation:

We have audited the accompanying consolidated financial statements of Ohio Valley Electric Corporation and its subsidiary company, Indiana-Kentucky Electric Corporation (the "Companies"), which comprise the consolidated balance sheets as of December 31, 2014 and 2013, and the related consolidated statements of income and retained earnings and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Companies' preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Companies' internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Companies as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Cincinnati, Ohio
April 16, 2015

OHIO VALLEY ELECTRIC CORPORATION
AND SUBSIDIARY COMPANY

OVEC PERFORMANCE—A 5-YEAR COMPARISON

	2014	2013	2012	2011	2010
Net Generation (MWh)	**11,410,006**	10,471,693	10,514,762	14,468,168	14,634,079
Energy Delivered (MWh) to:					
DOE [1]	**211,337**	195,470	207,692	253,157	249,139
Sponsors	**11,193,643**	10,304,107	10,340,568	14,199,025	14,421,180
Maximum Scheduled (MW) by:					
DOE [1]	**42**	33	36	39	39
Sponsors	**2,162**	2,160	2,165	2,247	2,223
Power Costs to:					
DOE [1]	**$11,758,000**	$9,282,000	$9,097,000	$11,643,000	$11,207,000
Sponsors	**$631,120,000**	$671,648,000	$650,027,000	$722,153,000	$671,671,000
Average Price (MWh):					
DOE [1]	**$55.636**	$47.483	$43.802	$45.993	$44.984
Sponsors	**$56.382**	$65.183	$62.862	$50.859	$46.575
Operating Revenues	**$656,174,000**	$675,649,000	$670,819,000	$716,938,000	$690,687,000
Operating Expenses	**$587,900,000**	$594,742,000	$599,891,000	$653,696,000	$618,790,000
Cost of Fuel Consumed	**$315,461,000**	$311,900,000	$302,926,000	$397,543,000	$358,507,000
Taxes (federal, state, and local)	**$12,426,000**	$12,312,000	$11,659,000	$12,059,000	$11,208,000
Payroll	**$62,275,000**	$63,175,000	$61,907,000	$57,141,000	$55,609,000
Fuel Burned (tons)	**5,183,311**	4,958,872	5,290,009	7,310,107	7,506,530
Heat Rate (Btu per kWh, net generation)	**10,483**	10,715	10,581	10,467	10,310
Unit Cost of Fuel Burned (per mmBtu)	**$2.64**	$2.78	$2.72	$2.63	$2.38
Equivalent Availability (percent)	**69.8**	73.9	78.9	83.0	81.0
Power Use Factor (percent)	**86.48**	75.05	69.40	89.61	92.82
Employees (year-end)	**775**	781	828	810	783

[1] OVEC purchases power from third party generators and provides certain services for the Department of Energy (DOE) at its Portsmouth facility under the terms and conditions of an Arranged Power Agreement (APA) dated May 1, 2003. On April 28, 2015, DOE and OVEC signed an agreement to terminate the APA effective July 31, 2015.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

DIRECTORS

Ohio Valley Electric Corporation

[1,2] **ANTHONY J. AHERN**, Columbus, Ohio
President and Chief Executive Officer
Buckeye Power Generating, LLC

[1] **NICHOLAS K. AKINS**, Columbus, Ohio
Chairman, President and Chief Executive Officer
American Electric Power Company, Inc.

ERIC D. BAKER, Cadillac, Michigan
President and Chief Executive Officer
Wolverine Power Supply Cooperative, Inc.

WAYNE D. GAMES, Evansville, Indiana
Vice President – Power Supply
Vectren Corporation

JAMES R. HANEY, Akron, Ohio
Vice President, Compliance & Regulated Services and Chief FERC Compliance Officer
FirstEnergy Corp.

PHILIP R. HERRINGTON, Dayton, Ohio
President, Competitive Generation
AES U.S. Strategic Business Unit

[2] **LANA L. HILLEBRAND**, Columbus, Ohio
Senior Vice President and Chief Administrative Officer
American Electric Power Company, Inc.

[1] **CHARLES D. LASKY**, Akron, Ohio
Vice President, Fossil Operations and Engineering
FirstEnergy Generation, LLC

[2] **MARK C. McCULLOUGH**, Columbus, Ohio
Executive Vice President - Generation
American Electric Power Company, Inc.

STEVEN K. NELSON, Coshocton, Ohio
Chairman, Buckeye Power Board of Trustees
The Frontier Power Company

PATRICK W. O'LOUGHLIN, Columbus, Ohio
Senior Vice President and Chief Operating Officer
Buckeye Power Generating, LLC

[1] **ROBERT P. POWERS**, Columbus, Ohio
Executive Vice President and Chief Operating Officer
American Electric Power Company, Inc.

[2] **PAUL W. THOMPSON**, Louisville, Kentucky
Chief Operating Officer
LG&E and KU Energy LLC

[1] **JOHN A. VERDERAME**, Charlotte, North Carolina
Managing Director, Power Trading & Dispatch
Duke Energy Corporation

[1] **JOHN N. VOYLES, JR.**, Louisville, Kentucky
Vice President, Transmission and Generation Services
LG&E and KU Energy LLC

Indiana-Kentucky Electric Corporation

[1] **ANTHONY J. AHERN**, Columbus, Ohio
President and Chief Executive Officer
Buckeye Power Generating, LLC

[1] **NICHOLAS K. AKINS**, Columbus, Ohio
Chairman, President and Chief Executive Officer
American Electric Power Company, Inc.

PAUL CHODAK, Fort Wayne, Indiana
President and Chief Operating Officer
Indiana Michigan Power

WAYNE D. GAMES, Evansville, Indiana
Vice President – Power Supply
Vectren Corporation

[1] **CHARLES D. LASKY**, Akron, Ohio
Vice President, Fossil Operations and Engineering
FirstEnergy Generation, LLC

MARC E. LEWIS, Fort Wayne, Indiana
Vice President, External Relations
Indiana Michigan Power

DAVID A. LUCAS, Fort Wayne, Indiana
Vice President Finance
Indiana Michigan Power

OFFICERS—OVEC AND IKEC

NICHOLAS K. AKINS
President

MARK A. PEIFER
Vice President and Chief Operating Officer

JOHN D. BRODT
Chief Financial Officer, Secretary and Treasurer

RONALD D. COOK
Assistant Secretary, Assistant Treasurer and Supply Chain Director

JULIE SLOAT
Assistant Secretary and Assistant Treasurer

JUSTIN J. COOPER
Assistant Secretary and Budget and Finance Manager

[1]Member of Executive Committee.
[2]Member of Human Resources Committee.

SC 13

Counties Violating the Primary Ground-level Ozone Standard

Based on Monitored Air Quality from 2011 - 2013
Includes only Counties with Monitors

(white)	Does not violate proposed range
(dark grey)	Violates 70 parts per billion
(light grey)	Violates 65 parts per billion

State Name	County Name	2011-2013 Concentrations 3-year average* Based on proposed 70 ppb	Based on proposed 65 ppb
Alabama	Baldwin	67	67
Alabama	Colbert	65	65
Alabama	De Kalb	66	66
Alabama	Elmore	64	64
Alabama	Etowah	61	61
Alabama	Houston	63	63
Alabama	Jefferson	76	76
Alabama	Madison	70	70
Alabama	Mobile	67	67
Alabama	Montgomery	65	65
Alabama	Morgan	68	68
Alabama	Russell	65	65
Alabama	Shelby	73	73
Alabama	Tuscaloosa	59	59
Alaska	Denali	52	52
Alaska	Fairbanks North Star	43	43
Arizona	Cochise	73	73
Arizona	Coconino	72	72
Arizona	Gila	75	75
Arizona	La Paz	72	72
Arizona	Maricopa	81	81
Arizona	Navajo	70	70
Arizona	Pima	73	73
Arizona	Pinal	76	76
Arizona	Yavapai	69	69
Arizona	Yuma	76	76
Arkansas	Clark	65	65
Arkansas	Crittenden	76	76
Arkansas	Newton	67	67
Arkansas	Polk	71	71
Arkansas	Pulaski	76	76
Arkansas	Washington	72	72

EXHIBIT
SC-13
PENGAD 800-631-6989

http://www3.epa.gov/airquality/ozonepollution/pdfs/20141126-20112013datatable.pdf

September 30, 2015

California	Alameda	71	71
California	Amador	71	71
California	Butte	76	76
California	Calaveras	72	72
California	Colusa	60	60
California	Contra Costa	68	68
California	El Dorado	82	82
California	Fresno	94	94
California	Glenn	65	65
California	Humboldt	45	45
California	Imperial	82	82
California	Inyo	72	72
California	Kern	89	89
California	Kings	84	84
California	Lake	60	60
California	Los Angeles	99	99
California	Madera	84	84
California	Marin	53	53
California	Mariposa	78	78
California	Mendocino	48	48
California	Merced	81	81
California	Monterey	57	57
California	Napa	59	59
California	Nevada	77	77
California	Orange	72	72
California	Placer	81	81
California	Riverside	101	101
California	Sacramento	90	90
California	San Benito	70	70
California	San Bernardino	107	107
California	San Diego	80	80
California	San Francisco	46	46
California	San Joaquin	79	79
California	San Luis Obispo	77	77
California	San Mateo	53	53
California	Santa Barbara	65	65
California	Santa Clara	68	68
California	Santa Cruz	51	51
California	Shasta	68	68
California	Siskiyou	61	61
California	Solano	67	67
California	Sonoma	53	53
California	Stanislaus	86	86
California	Sutter	74	74
California	Tehama	74	74
California	Tulare	93	93
California	Tuolumne	73	73

California	Ventura	79	79
California	Yolo	69	69
Colorado	Adams	76	76
Colorado	Arapahoe	79	79
Colorado	Boulder	77	77
Colorado	Denver	65	65
Colorado	Douglas	83	83
Colorado	El Paso	74	74
Colorado	Garfield	65	65
Colorado	Gunnison	66	66
Colorado	Jackson	56	56
Colorado	Jefferson	83	83
Colorado	La Plata	72	72
Colorado	Larimer	80	80
Colorado	Mesa	67	67
Colorado	Moffat	63	63
Colorado	Montezuma	69	69
Colorado	Rio Blanco	77	77
Colorado	Weld	76	76
Connecticut	Fairfield	89	89
Connecticut	Hartford	76	76
Connecticut	Litchfield	70	70
Connecticut	Middlesex	81	81
Connecticut	New Haven	89	89
Connecticut	New London	84	84
Connecticut	Tolland	78	78
Connecticut	Windham	71	71
Delaware	Kent	74	74
Delaware	New Castle	76	76
Delaware	Sussex	77	77
District of Columbia	District of Columbia	79	79
Florida	Alachua	63	63
Florida	Baker	61	61
Florida	Bay	66	66
Florida	Brevard	64	64
Florida	Broward	59	59
Florida	Collier	60	60
Florida	Columbia	61	61
Florida	Duval	62	62
Florida	Escambia	70	70
Florida	Flagler	60	60
Florida	Highlands	62	62
Florida	Hillsborough	71	71
Florida	Holmes	62	62
Florida	Indian River	65	65
Florida	Lake	65	65
Florida	Lee	64	64

Florida	Leon	65	65
Florida	Liberty	59	59
Florida	Manatee	67	67
Florida	Marion	63	63
Florida	Miami-Dade	64	64
Florida	Okaloosa	64	64
Florida	Orange	71	71
Florida	Osceola	66	66
Florida	Palm Beach	62	62
Florida	Pasco	67	67
Florida	Pinellas	67	67
Florida	Polk	68	68
Florida	Santa Rosa	69	69
Florida	Sarasota	71	71
Florida	Seminole	67	67
Florida	Volusia	63	63
Florida	Wakulla	63	63
Georgia	Bibb	71	71
Georgia	Chatham	62	62
Georgia	Chattooga	65	65
Georgia	Clarke	68	68
Georgia	Cobb	73	73
Georgia	Columbia	68	68
Georgia	Coweta	62	62
Georgia	Dawson	64	64
Georgia	De Kalb	75	75
Georgia	Douglas	71	71
Georgia	Fulton	80	80
Georgia	Glynn	58	58
Georgia	Gwinnett	77	77
Georgia	Henry	80	80
Georgia	Murray	68	68
Georgia	Muscogee	64	64
Georgia	Paulding	69	69
Georgia	Pike	72	72
Georgia	Richmond	69	69
Georgia	Rockdale	77	77
Georgia	Sumter	63	63
Hawaii	Honolulu	49	49
Idaho	Ada	68	69
Idaho	Butte	63	63
Illinois	Adams	68	68
Illinois	Champaign	72	72
Illinois	Clark	67	67
Illinois	Cook	80	80
Illinois	Du Page	68	68
Illinois	Effingham	67	67

Illinois	Hamilton	74	74
Illinois	Jersey	77	77
Illinois	Jo Daviess	68	68
Illinois	Kane	69	69
Illinois	Lake	80	80
Illinois	Macon	71	71
Illinois	Macoupin	71	71
Illinois	Madison	80	80
Illinois	McHenry	71	71
Illinois	Mclean	72	72
Illinois	Peoria	71	71
Illinois	Randolph	70	70
Illinois	Rock Island	60	60
Illinois	Sangamon	72	72
Illinois	St Clair	75	75
Illinois	Will	64	64
Illinois	Winnebago	68	68
Indiana	Allen	69	69
Indiana	Boone	73	73
Indiana	Carroll	69	69
Indiana	Clark	78	78
Indiana	Delaware	68	68
Indiana	Elkhart	67	67
Indiana	Floyd	78	78
Indiana	Greene	76	76
Indiana	Hamilton	70	70
Indiana	Hancock	64	64
Indiana	Hendricks	65	65
Indiana	Huntington	65	65
Indiana	Jackson	65	65
Indiana	Johnson	68	68
Indiana	Knox	73	73
Indiana	La Porte	83	83
Indiana	Lake	70	70
Indiana	Madison	69	69
Indiana	Marion	74	74
Indiana	Morgan	70	70
Indiana	Perry	73	73
Indiana	Porter	72	72
Indiana	Posey	70	70
Indiana	Shelby	75	75
Indiana	St Joseph	73	73
Indiana	Vanderburgh	74	74
Indiana	Vigo	67	67
Indiana	Wabash	73	73
Indiana	Warrick	73	73
Iowa	Bremer	64	64

Iowa	Clinton	68	68
Iowa	Harrison	69	69
Iowa	Linn	65	65
Iowa	Montgomery	65	65
Iowa	Palo Alto	67	67
Iowa	Polk	61	61
Iowa	Scott	66	66
Iowa	Story	62	62
Iowa	Van Buren	66	66
Iowa	Warren	64	64
Kansas	Johnson	73	73
Kansas	Leavenworth	73	73
Kansas	Linn	71	71
Kansas	Riley	70	70
Kansas	Sedgwick	77	77
Kansas	Shawnee	73	73
Kansas	Sumner	76	76
Kansas	Trego	72	72
Kansas	Wyandotte	70	70
Kentucky	Bell	62	62
Kentucky	Boone	67	67
Kentucky	Boyd	69	69
Kentucky	Bullitt	72	72
Kentucky	Campbell	78	78
Kentucky	Carter	66	66
Kentucky	Christian	69	69
Kentucky	Daviess	77	77
Kentucky	Edmonson	71	71
Kentucky	Fayette	71	71
Kentucky	Greenup	69	69
Kentucky	Hancock	73	73
Kentucky	Hardin	70	70
Kentucky	Henderson	76	76
Kentucky	Jefferson	79	79
Kentucky	Jessamine	70	70
Kentucky	Livingston	74	74
Kentucky	McCracken	74	74
Kentucky	Morgan	66	66
Kentucky	Oldham	82	82
Kentucky	Perry	63	63
Kentucky	Pike	63	63
Kentucky	Pulaski	67	67
Kentucky	Simpson	67	67
Kentucky	Trigg	70	70
Kentucky	Washington	69	69
Louisiana	Ascension	71	71
Louisiana	Bossier	74	74

Louisiana	Caddo	73	73
Louisiana	Calcasieu	70	70
Louisiana	East Baton Rouge	75	75
Louisiana	Iberville	75	75
Louisiana	Jefferson	70	70
Louisiana	Lafayette	69	69
Louisiana	Lafourche	71	71
Louisiana	Livingston	72	72
Louisiana	Orleans	68	68
Louisiana	Ouachita	61	61
Louisiana	Pointe Coupee	74	74
Louisiana	St Bernard	69	69
Louisiana	St Charles	67	67
Louisiana	St James	66	66
Louisiana	St John The Baptist	72	72
Louisiana	St Tammany	72	72
Louisiana	West Baton Rouge	68	68
Maine	Androscoggin	61	61
Maine	Aroostook	51	51
Maine	Cumberland	69	70
Maine	Hancock	69	69
Maine	Kennebec	64	64
Maine	Knox	68	68
Maine	Oxford	54	54
Maine	Penobscot	59	59
Maine	Sagadahoc	61	61
Maine	Washington	58	58
Maine	York	75	75
Maryland	Anne Arundel	81	81
Maryland	Baltimore	78	78
Maryland	Baltimore City	72	72
Maryland	Calvert	77	77
Maryland	Carroll	74	74
Maryland	Cecil	82	82
Maryland	Charles	77	78
Maryland	Dorchester	75	75
Maryland	Frederick	74	74
Maryland	Garrett	71	71
Maryland	Harford	85	85
Maryland	Kent	80	80
Maryland	Montgomery	74	74
Maryland	Prince Georges	81	81
Maryland	Washington	71	71
Massachusetts	Barnstable	72	72
Massachusetts	Berkshire	68	69
Massachusetts	Dukes	75	75
Massachusetts	Essex	71	71

Massachusetts	Hampden	73	73
Massachusetts	Hampshire	70	70
Massachusetts	Middlesex	67	67
Massachusetts	Norfolk	72	72
Massachusetts	Suffolk	68	68
Massachusetts	Worcester	68	68
Michigan	Allegan	86	86
Michigan	Benzie	74	74
Michigan	Berrien	82	82
Michigan	Cass	78	78
Michigan	Chippewa	64	64
Michigan	Clinton	71	71
Michigan	Genesee	74	74
Michigan	Huron	72	72
Michigan	Ingham	72	72
Michigan	Kalamazoo	75	75
Michigan	Kent	74	74
Michigan	Lenawee	75	75
Michigan	Macomb	77	77
Michigan	Manistee	74	74
Michigan	Mason	75	75
Michigan	Missaukee	70	70
Michigan	Muskegon	81	81
Michigan	Oakland	76	76
Michigan	Ottawa	77	77
Michigan	Schoolcraft	72	72
Michigan	St Clair	75	75
Michigan	Tuscola	70	70
Michigan	Washtenaw	75	75
Michigan	Wayne	77	77
Michigan	Wexford	66	66
Minnesota	Anoka	67	67
Minnesota	Becker	61	61
Minnesota	Carlton	56	56
Minnesota	Crow Wing	62	62
Minnesota	Goodhue	63	63
Minnesota	Lake	58	58
Minnesota	Lyon	65	65
Minnesota	Mille Lacs	60	60
Minnesota	Olmsted	64	64
Minnesota	Scott	65	65
Minnesota	St Louis	59	59
Minnesota	Stearns	62	62
Minnesota	Wright	63	63
Mississippi	Bolivar	71	71
Mississippi	De Soto	70	70
Mississippi	Hancock	66	66

Mississippi	Harrison	69	69
Mississippi	Hinds	66	66
Mississippi	Jackson	70	70
Mississippi	Lauderdale	63	63
Mississippi	Lee	64	64
Mississippi	Yalobusha	63	63
Missouri	Andrew	73	73
Missouri	Boone	69	69
Missouri	Callaway	68	68
Missouri	Cass	71	71
Missouri	Cedar	73	73
Missouri	Clay	78	78
Missouri	Clinton	78	78
Missouri	Greene	72	72
Missouri	Jasper	77	77
Missouri	Jefferson	76	76
Missouri	Lincoln	78	78
Missouri	Monroe	68	68
Missouri	Perry	73	73
Missouri	St Charles	82	82
Missouri	St Louis	80	80
Missouri	St Louis City	77	77
Missouri	Ste Genevieve	72	72
Missouri	Taney	68	68
Montana	Flathead	54	54
Montana	Lewis and Clark	54	54
Montana	Missoula	55	55
Montana	Powder River	55	55
Montana	Rosebud	55	55
Nebraska	Douglas	67	67
Nebraska	Knox	68	68
Nebraska	Lancaster	55	55
Nevada	Churchill	56	56
Nevada	Clark	77	77
Nevada	Lyon	69	69
Nevada	Washoe	68	68
Nevada	White Pine	74	74
New Hampshire	Belknap	62	62
New Hampshire	Cheshire	62	62
New Hampshire	Coos	69	69
New Hampshire	Grafton	60	60
New Hampshire	Hillsborough	67	67
New Hampshire	Merrimack	64	64
New Hampshire	Rockingham	68	68
New Jersey	Atlantic	73	73
New Jersey	Bergen	77	77
New Jersey	Camden	81	81

New Jersey	Cumberland	70	70
New Jersey	Essex	76	76
New Jersey	Gloucester	84	84
New Jersey	Hudson	72	72
New Jersey	Hunterdon	77	77
New Jersey	Mercer	76	76
New Jersey	Middlesex	79	79
New Jersey	Monmouth	78	78
New Jersey	Morris	76	76
New Jersey	Ocean	80	80
New Jersey	Passaic	72	72
New Jersey	Warren	66	66
New Mexico	Bernalillo	72	72
New Mexico	Dona Ana	75	75
New Mexico	Eddy	71	71
New Mexico	Grant	63	63
New Mexico	Lea	66	66
New Mexico	Luna	67	67
New Mexico	San Juan	71	71
New Mexico	Sandoval	63	63
New Mexico	Santa Fe	66	66
New Mexico	Valencia	70	70
New York	Albany	67	67
New York	Bronx	74	74
New York	Chautauqua	72	72
New York	Dutchess	70	70
New York	Erie	72	72
New York	Essex	70	70
New York	Franklin	39	39
New York	Hamilton	66	66
New York	Herkimer	61	63
New York	Jefferson	70	70
New York	Monroe	68	68
New York	New York	72	72
New York	Niagara	73	73
New York	Onondaga	69	69
New York	Orange	63	63
New York	Oswego	67	67
New York	Putnam	68	68
New York	Queens	79	79
New York	Richmond	78	78
New York	Rockland	74	74
New York	Saratoga	65	65
New York	Steuben	64	64
New York	Suffolk	81	81
New York	Tompkins	67	67
New York	Wayne	65	65

New York	Westchester	75	75
North Carolina	Alexander	65	65
North Carolina	Avery	63	63
North Carolina	Buncombe	65	65
North Carolina	Caldwell	64	64
North Carolina	Carteret	61	61
North Carolina	Caswell	69	69
North Carolina	Chatham	61	61
North Carolina	Cumberland	69	69
North Carolina	Davie	69	69
North Carolina	Durham	68	68
North Carolina	Edgecombe	69	69
North Carolina	Forsyth	73	73
North Carolina	Franklin	68	68
North Carolina	Graham	68	68
North Carolina	Granville	69	69
North Carolina	Guilford	72	72
North Carolina	Haywood	69	69
North Carolina	Johnston	70	70
North Carolina	Lenoir	67	67
North Carolina	Lincoln	72	72
North Carolina	Macon	63	63
North Carolina	Martin	66	66
North Carolina	Mecklenburg	78	78
North Carolina	Montgomery	66	66
North Carolina	New Hanover	64	64
North Carolina	Person	69	69
North Carolina	Pitt	69	69
North Carolina	Rockingham	69	69
North Carolina	Rowan	73	73
North Carolina	Swain	58	58
North Carolina	Union	70	70
North Carolina	Wake	71	71
North Carolina	Yancey	68	68
North Dakota	Billings	57	57
North Dakota	Burke	58	58
North Dakota	Burleigh	58	58
North Dakota	Cass	59	59
North Dakota	Dunn	56	56
North Dakota	Mckenzie	58	58
North Dakota	Mercer	59	59
North Dakota	Oliver	58	58
Ohio	Allen	73	73
Ohio	Ashtabula	75	75
Ohio	Butler	78	78
Ohio	Clark	75	75
Ohio	Clermont	79	79

Ohio	Clinton	78	78
Ohio	Cuyahoga	78	78
Ohio	Delaware	73	73
Ohio	Fayette	72	72
Ohio	Franklin	80	80
Ohio	Geauga	73	73
Ohio	Greene	73	73
Ohio	Hamilton	81	81
Ohio	Jefferson	71	71
Ohio	Knox	73	73
Ohio	Lake	80	80
Ohio	Lawrence	68	68
Ohio	Licking	73	73
Ohio	Lorain	71	71
Ohio	Lucas	74	74
Ohio	Madison	74	74
Ohio	Mahoning	70	70
Ohio	Medina	69	69
Ohio	Miami	74	74
Ohio	Montgomery	76	76
Ohio	Noble	66	66
Ohio	Portage	67	67
Ohio	Preble	72	72
Ohio	Stark	76	76
Ohio	Summit	68	68
Ohio	Trumbull	76	76
Ohio	Warren	76	76
Ohio	Washington	69	69
Ohio	Wood	71	71
Oklahoma	Adair	75	75
Oklahoma	Caddo	75	76
Oklahoma	Canadian	76	76
Oklahoma	Cherokee	74	74
Oklahoma	Cleveland	76	76
Oklahoma	Comanche	77	77
Oklahoma	Creek	78	78
Oklahoma	Dewey	74	74
Oklahoma	Kay	77	77
Oklahoma	Mayes	78	78
Oklahoma	Mcclain	74	74
Oklahoma	Oklahoma	79	79
Oklahoma	Ottawa	76	76
Oklahoma	Pittsburg	75	75
Oklahoma	Sequoyah	72	72
Oklahoma	Tulsa	80	80
Oregon	Clackamas	62	62
Oregon	Columbia	50	50

Oregon	Deschutes	58	58
Oregon	Jackson	63	63
Oregon	Lane	59	59
Oregon	Marion	58	58
Oregon	Multnomah	56	56
Oregon	Umatilla	62	62
Oregon	Washington	56	56
Pennsylvania	Adams	70	70
Pennsylvania	Allegheny	76	76
Pennsylvania	Armstrong	75	75
Pennsylvania	Beaver	75	75
Pennsylvania	Berks	73	73
Pennsylvania	Blair	73	73
Pennsylvania	Bucks	78	78
Pennsylvania	Cambria	70	70
Pennsylvania	Centre	72	72
Pennsylvania	Chester	76	76
Pennsylvania	Clearfield	71	71
Pennsylvania	Dauphin	74	74
Pennsylvania	Delaware	76	76
Pennsylvania	Elk	66	66
Pennsylvania	Erie	74	74
Pennsylvania	Franklin	68	68
Pennsylvania	Greene	67	67
Pennsylvania	Indiana	75	75
Pennsylvania	Lackawanna	70	70
Pennsylvania	Lancaster	75	75
Pennsylvania	Lawrence	73	73
Pennsylvania	Lebanon	76	76
Pennsylvania	Lehigh	74	74
Pennsylvania	Luzerne	65	65
Pennsylvania	Lycoming	66	66
Pennsylvania	Mercer	77	77
Pennsylvania	Monroe	64	64
Pennsylvania	Montgomery	74	74
Pennsylvania	Northampton	71	71
Pennsylvania	Perry	68	68
Pennsylvania	Philadelphia	80	80
Pennsylvania	Somerset	65	65
Pennsylvania	Tioga	69	69
Pennsylvania	Washington	71	71
Pennsylvania	Westmoreland	73	73
Pennsylvania	York	74	74
Rhode Island	Kent	74	74
Rhode Island	Providence	76	76
Rhode Island	Washington	78	78
South Carolina	Abbeville	60	60

South Carolina	Aiken	62	62
South Carolina	Anderson	68	68
South Carolina	Berkeley	61	61
South Carolina	Charleston	63	63
South Carolina	Chesterfield	62	62
South Carolina	Colleton	56	56
South Carolina	Darlington	66	66
South Carolina	Edgefield	58	58
South Carolina	Greenville	67	67
South Carolina	Pickens	67	67
South Carolina	Richland	69	70
South Carolina	Spartanburg	72	72
South Carolina	York	63	63
South Dakota	Brookings	64	64
South Dakota	Custer	63	63
South Dakota	Jackson	59	59
South Dakota	Meade	62	62
South Dakota	Minnehaha	68	68
Tennessee	Anderson	69	69
Tennessee	Blount	74	74
Tennessee	Claiborne	62	62
Tennessee	Davidson	70	70
Tennessee	Dekalb	67	67
Tennessee	Hamilton	71	71
Tennessee	Jefferson	73	73
Tennessee	Knox	70	70
Tennessee	Loudon	70	70
Tennessee	Meigs	69	69
Tennessee	Sevier	72	72
Tennessee	Shelby	78	78
Tennessee	Sullivan	71	71
Tennessee	Sumner	76	76
Tennessee	Williamson	69	69
Tennessee	Wilson	70	70
Texas	Bell	74	74
Texas	Bexar	81	81
Texas	Brazoria	87	87
Texas	Brewster	71	71
Texas	Cameron	60	60
Texas	Collin	84	84
Texas	Dallas	84	84
Texas	Denton	87	87
Texas	El Paso	72	72
Texas	Ellis	77	77
Texas	Galveston	74	74
Texas	Gregg	77	77
Texas	Harris	82	82

Texas	Harrison	72	72
Texas	Hidalgo	59	59
Texas	Hood	77	77
Texas	Hunt	74	74
Texas	Jefferson	75	75
Texas	Johnson	79	79
Texas	Kaufman	74	74
Texas	McLennan	74	74
Texas	Montgomery	79	79
Texas	Navarro	72	72
Texas	Nueces	70	70
Texas	Orange	69	69
Texas	Parker	79	79
Texas	Polk	68	68
Texas	Randall	73	73
Texas	Rockwall	77	77
Texas	Smith	75	75
Texas	Tarrant	86	86
Texas	Travis	73	73
Texas	Victoria	67	67
Texas	Webb	64	64
Utah	Box Elder	69	69
Utah	Cache	67	67
Utah	Carbon	69	69
Utah	Davis	68	68
Utah	Duchesne	68	68
Utah	Garfield	57	57
Utah	Salt Lake	76	76
Utah	San Juan	69	69
Utah	Tooele	72	72
Utah	Utah	73	73
Utah	Washington	72	72
Utah	Weber	74	74
Vermont	Bennington	62	63
Vermont	Chittenden	61	61
Virginia	Albemarle	65	65
Virginia	Arlington	79	79
Virginia	Caroline	71	71
Virginia	Charles City	73	73
Virginia	Chesterfield	69	69
Virginia	Fairfax	79	79
Virginia	Fauquier	61	61
Virginia	Frederick	65	65
Virginia	Giles	63	63
Virginia	Hampton City	72	72
Virginia	Hanover	72	72
Virginia	Henrico	73	73

Virginia	Loudoun	71	71
Virginia	Madison	69	69
Virginia	Page	65	65
Virginia	Prince Edward	62	62
Virginia	Prince William	69	69
Virginia	Roanoke	64	64
Virginia	Rockbridge	60	60
Virginia	Rockingham	65	65
Virginia	Stafford	71	71
Virginia	Suffolk City	70	70
Virginia	Wythe	63	63
Washington	Clallam	52	52
Washington	Clark	55	55
Washington	King	62	62
Washington	Pierce	58	58
Washington	Skagit	44	44
Washington	Spokane	60	60
Washington	Thurston	55	55
Washington	Whatcom	44	44
West Virginia	Berkeley	66	66
West Virginia	Cabell	69	70
West Virginia	Gilmer	60	60
West Virginia	Greenbrier	63	63
West Virginia	Hancock	72	72
West Virginia	Kanawha	73	73
West Virginia	Monongalia	68	69
West Virginia	Ohio	70	70
West Virginia	Tucker	65	65
West Virginia	Wood	68	68
Wisconsin	Ashland	59	59
Wisconsin	Brown	70	70
Wisconsin	Columbia	69	69
Wisconsin	Dane	69	69
Wisconsin	Dodge	72	72
Wisconsin	Door	75	75
Wisconsin	Eau Claire	62	62
Wisconsin	Fond Du Lac	72	72
Wisconsin	Forest	66	66
Wisconsin	Kenosha	82	82
Wisconsin	Kewaunee	74	74
Wisconsin	La Crosse	64	64
Wisconsin	Manitowoc	79	79
Wisconsin	Marathon	65	65
Wisconsin	Milwaukee	78	78
Wisconsin	Outagamie	72	72
Wisconsin	Ozaukee	77	77
Wisconsin	Racine	77	77

Wisconsin	Rock	72	72
Wisconsin	Sauk	67	67
Wisconsin	Sheboygan	85	85
Wisconsin	Taylor	63	63
Wisconsin	Vilas	62	62
Wisconsin	Walworth	71	71
Wisconsin	Waukesha	67	67
Wyoming	Albany	69	69
Wyoming	Campbell	64	64
Wyoming	Carbon	62	62
Wyoming	Fremont	66	66
Wyoming	Laramie	68	68
Wyoming	Natrona	60	60
Wyoming	Sublette	76	76
Wyoming	Sweetwater	66	66
Wyoming	Teton	65	65
Wyoming	Uinta	65	65
		358 violating counties	**200 additional violating counties**

*This chart shows two columns of air quality levels because the calculation of the 3-year concentration is dependent on the level of the proposed standard level. For information on that calculation, please see 40 CFR Part 50 Appendix P.